BAYTEX
ENERGY CORP.

Q1 REPORT 2017

SUMMARY

- Generated production of 69,298 boe/d (79% oil and NGL) during Q1/2017, an increase of 6% from Q4/2016;
- Delivered funds from operations ("FFO") of $81.4 million ($0.35 per basic share) in Q1/2017;
- Produced 36,081 boe/d in the Eagle Ford, an increase of 8% from Q4/2016, and 33,217 boe/d in Canada, an increase of 5% from Q4/2016;
- Realized an operating netback (sales price less royalties, operating and transportation expenses) in Q1/2017 of $19.42/boe ($19.46/boe including financial derivatives gain);
- Increased pace of development in the Eagle Ford to five drilling rigs and two completion crews with record low well costs of approximately US$4.5 million despite increasing frac stages and proppant usage during Q1/2017;
- Executed our Q1/2017 drilling program in Canada drilling 17 net heavy oil wells with strong initial results at Peace River and Lloydminster; and
- Integrated the Peace River acquisition which closed on January 20, 2017. From the time of closing, production on these assets has increased by approximately 13% as we initiated phase one of our plan to bring shut-in production back on-line.

	Three Months Ended		
	March 31, 2017	December 31, 2016	March 31, 2016
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*			
Petroleum and natural gas sales	$ 260,549	$ 233,116	$ 153,598
Funds from operations[1]	81,369	77,239	45,645
Per share – basic	0.35	0.36	0.22
Per share – diluted	0.34	0.36	0.22
Net income (loss)	11,096	(359,424)	607
Per share – basic	0.05	(1.66)	0.00
Per share – diluted	0.05	(1.66)	0.00
Exploration and development	96,559	68,029	81,685
Acquisitions, net of divestitures	66,004	(322)	(9)
Total oil and natural gas capital expenditures	$ 162,563	$ 55,556	$ 81,676
Bank loan[2]	$ 259,966	$ 191,286	$ 290,465
Long-term notes[2]	1,574,116	1,584,158	1,540,546
Long-term debt	1,834,082	1,775,444	1,831,011
Working capital deficiency (surplus)	16,827	(1,903)	150,332
Net debt[3]	$ 1,850,909	$ 1,773,541	$ 1,981,343

	Three Months Ended		
	March 31, 2017	December 31, 2016	March 31, 2016
OPERATING			
Daily production			
Heavy oil (bbl/d)	**24,625**	22,982	24,807
Light oil and condensate (bbl/d)	**21,617**	20,163	24,489
NGL (bbl/d)	**8,306**	8,319	10,109
Total oil and NGL (bbl/d)	**54,548**	51,464	59,405
Natural gas (mcf/d)	**88,502**	82,032	98,220
Oil equivalent (boe/d @ 6:1)[4]	**69,298**	65,136	75,776
Benchmark prices			
WTI oil (US$/bbl)	**51.91**	49.29	33.45
WCS heavy oil (US$/bbl)	**37.34**	34.97	19.22
Edmonton par oil ($/bbl)	**63.98**	61.58	40.80
LLS oil (US$/bbl)	**52.50**	49.95	33.24
Baytex average prices (before hedging)			
Heavy oil ($/bbl)[5]	**35.96**	34.33	12.54
Light oil and condensate ($/bbl)	**63.26**	60.12	37.97
NGL ($/bbl)	**26.35**	22.64	18.38
Total oil and NGL ($/bbl)	**45.31**	42.55	24.02
Natural gas ($/mcf)	**3.52**	3.61	2.40
Oil equivalent ($/boe)	**40.16**	38.16	21.93
CAD/USD noon rate at period end	**1.3322**	1.3427	1.2971
CAD/USD average rate for period	**1.3229**	1.3339	1.3748
COMMON SHARE INFORMATION			
TSX			
Share price (Cdn$)			
High	**6.97**	7.35	5.39
Low	**4.02**	4.85	1.57
Close	**4.54**	6.56	5.13
Volume traded (thousands)	**255,645**	351,040	483,311
NYSE			
Share price (US$)			
High	**5.19**	5.61	4.15
Low	**3.01**	3.60	1.08
Close	**3.65**	4.48	3.97
Volume traded (thousands)	**136,666**	186,423	154,052
Common shares outstanding (thousands)	**234,203**	233,449	210,689

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 three months ended March 31, 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 exclude condensate blending.*

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2017 production and capital expenditure guidance; our 2016-2017 exit production organic growth rate; our Eagle Ford assets, including our assessment that it is a premier oil resource play, that development is shifting to the northern oil window; our inventory of development prospects (in years based on 2017 activity levels), the cost to drill, complete and equip a well, initial production rates from new wells drilled in Q1/2017, 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, that our recently completed acquisition will drive efficiencies and synergies in our operations and significantly enhances our drilling inventory, our total inventory of potential drilling locations (both in number and years (based on 2017 activity levels)), our plan for bringing shut-in production volumes back on-line, our expectation that we will achieve meaningful operating cost improvements in 2017, 2018 and beyond, the cost to drill, complete and equip a well, initial production rates from wells drilled in Q1/2017 and the number of multi-lateral wells to be drilled in 2017; our Lloydminster assets, including our expectation that multi-lateral drilling will improve individual well capital efficiencies, the cost to drill, complete and equip a multi-lateral horizontal well, initial production rates from multi-lateral horizontal wells, 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 belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; our target for capital expenditures to approximate funds from operations; 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; and the percentage of our anticipated 2017 oil and natural gas production that is hedged. 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. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

Advisory Regarding Oil and Gas Information

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.

This report 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 our 2016 reserves report). At Lloydminster, our net drilling locations include 279 proved, 103 probable and 252 unbooked locations.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on 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.

CEO APPOINTMENT

As previously announced in December 2016, Ed LaFehr has been appointed Chief Executive Officer, succeeding James Bowzer. Mr. Bowzer, who has been in the role since September 2012, has worked with Mr. LaFehr to ensure a seamless leadership transition and will remain on the Board of Directors. Mr. LaFehr has been nominated for election as a Director at our Annual Meeting of Shareholders to be held on May 4, 2017.

Mr. LaFehr joined Baytex in July 2016 as President and has been an integral member of the executive leadership team, holding responsibility for the Canadian and U.S. business operations and corporate development. Mr. LaFehr has a long track record of success in the oil and gas industry leading organizations, growing assets and joint ventures, and driving capital and cost efficiencies.

MESSAGE TO SHAREHOLDERS

Operating Results

Our operating results for the first quarter reflect an increased pace of drilling activity in the Eagle Ford that began late in Q4/2016, the resumption of drilling activity in Canada and an initial contribution from our Peace River acquisition.

Production increased 6% to average 69,298 boe/d (79% oil and NGL) in Q1/2017, as compared to 65,136 boe/d (79% oil and NGL) in Q4/2016. Capital expenditures for exploration and development activities totaled $96.6 million in Q1/2017 and included the drilling of 67 (35.5 net) wells with a 100% success rate.

Reflective of our strong first quarter operating results and planned activity level for the balance of the year, we are tightening our 2017 production guidance range to 68,000 to 70,000 boe/d (previously 66,000 to 70,000 boe/d). At the mid-point of our guidance range, this reflects an increase of 1.5%. Our expected exit production rate for 2017 now reflects an organic growth rate of approximately 5-6% over our 2016 exit production rate, as compared to our prior expectation of 3-4%. We are now forecasting full-year 2017 exploration and development capital expenditures of $325 to $350 million (previously $300 to $350 million).

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 Q1/2017, we directed 60% of our exploration and development expenditures toward these assets.

Production increased 8% during the first quarter to average 36,081 boe/d (76% liquids), as compared to 33,432 boe/d in Q4/2016. During the first quarter, we averaged 5 drilling rigs and 2 completion crews on our lands.

In Q1/2017, we participated in the drilling of 36 (8.4 net) wells and commenced production from 33 (9.4 net) wells. The wells that commenced production during the quarter have established 30-day initial production rates of approximately 1,250 boe/d. A recently completed pad within the oil window of our Longhorn acreage established 30-day initial production rates of approximately 1,450 boe/d. At quarter end, we had 44 (10.7 net) wells waiting on completion.

We continued to see record low well costs during the first 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 Q1/2017, we increased the effective number of frac stages per well to 28 (from 22 in Q1/2016) and the amount of proppant per completed foot to 1,800 pounds (from 1,000 pounds in Q1/2016).

Our pace of development in the Eagle Ford is expected to remain stable throughout 2017 with 4-5 drilling rigs and 2 completion crews working on our lands. At this pace, we expect to bring approximately 34 net wells on production in 2017.

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 first quarter averaged approximately 17,000 boe/d (93% heavy oil).

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 $66 million. At the time of closing, the assets were producing approximately 3,000 boe/d.

Since closing the acquisition, production has increased by approximately 13% as we initiated phase one of our plan to bring approximately 3,000 boe/d of shut-in production back on-line. During the first quarter, we restarted 29 wells at a total cost of approximately $0.5 million, which resulted in an incremental 400 boe/d of production and capital efficiencies of approximately $1,250 per boe/d. Phase two will include additional gas conservation and vapour recovery systems that are expected to be implemented over the next 6-18 months. We are also undertaking an extensive review of the operations to ensure regulatory compliance and identify opportunities to reduce operating costs. We expect to achieve a 15-20% reduction in operating costs on the acquired assets in 2017 with further improvements anticipated in 2018 and beyond.

During the first quarter, we drilled 4 (4.0 net) multi-lateral horizontal wells (average of 12 laterals per well), two of which have been producing for more than 30 days and have established 30-day initial production rates of 614 bbl/d and 489 bbl/d. The cost to drill, complete and equip a multi-lateral well at Peace River is approximately $2.5 million, representing an 11% improvement from the wells we drilled in Q3/2015.

We plan to drill a total of 11 net multi-lateral horizontal wells at Peace River in 2017.

Lloydminster

Our Lloydminster region, which straddles the Alberta and Saskatchewan border, produced approximately 9,100 boe/d (98% heavy oil) during the first quarter, unchanged from Q4/2016. This area is characterized by multiple stacked pay formations at relatively shallow depths, which we have successfully developed through vertical and horizontal drilling, waterflood and SAGD operations.

During the first quarter, we drilled 17 (13.1 net) wells, including 12 (12.0 net) operated wells. 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 drilled 8 (8.0 net) multi-lateral horizontal wells in 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 average 30-day initial production rates of 90-150 bbl/d. Through efficient operational execution and lower service costs, the cost to drill, complete and equip our first eight multi-lateral wells have come in approximately 15% below budget with 30-day initial production rates meeting expectations.

We plan to drill a total of 52 net wells at Lloydminster in 2017. At this pace of development, we have a drilling inventory of over 10 years on these lands.

Financial Review

We generated FFO of $81.4 million ($0.35 per share) in Q1/2017, compared to $77.2 million ($0.36 per share) in Q4/2016. The increase in FFO is largely due to higher production and commodity prices, offset by lower realized hedging gains.

Financial Liquidity

Our net debt totaled $1.85 billion at March 31, 2017, as compared to $1.78 billion at December 31, 2016. The increase in net debt primarily relates to the Peace River acquisition that closed in January 2017 and was funded with a $115 million equity issue that closed in December 2016.

We continue to maintain strong financial liquidity with our US$575 million revolving credit facilities one-third drawn and our first meaningful long-term note maturity is not until 2021. With our strategy to spend within funds from operations, we expect this liquidity position to be stable going forward.

Our revolving credit facilities, which currently mature 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 March 31, 2017 was 0.7:1.00, compared to a maximum permitted ratio of 5.00:1.00, and our interest coverage ratio was 4.0:1.00, compared to a minimum required ratio of 1.25:1.00.

Operating Netback

During the first quarter, our operating netback improved as compared to Q4/2016. In Q1/2017, the price for West Texas Intermediate light oil ("WTI") averaged US$51.91/bbl, as compared to US$49.29/bbl in Q4/2016. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, increased slightly during Q1/2017, averaging US$14.58/bbl, as compared to US$14.32/bbl in Q4/2016.

We generated an operating netback in Q1/2017 of $19.42/boe ($19.46/boe including financial derivatives gain), as compared to $17.62/boe ($19.24/boe including financial derivatives gain) in Q4/2016 and $5.82/boe ($12.29/boe including financial derivatives gain) in Q1/2016. The Eagle Ford generated an operating netback of $26.83/boe during Q1/2017 while our Canadian operations generated an operating netback of $11.37/boe.

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

	Three Months Ended March 31					
	2017			2016		
($ per boe except for sales volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	33,217	36,081	69,298	34,709	41,067	75,776
Realized sales price	$ 32.81	$ 46.93	$ 40.16	$ 13.55	$ 29.02	$ 21.93
Less:						
Royalty	4.23	13.72	9.17	1.21	8.23	5.02
Operating expense	14.52	6.38	10.28	10.97	9.38	10.11
Transportation expense	2.69	–	1.29	2.14	–	0.98
Operating netback	$ 11.37	$ 26.83	$ 19.42	$ (0.77)	$ 11.41	$ 5.82
Realized financial derivatives gain	–	–	0.04	–	–	6.47
Operating netback after financial derivatives gain	$ 11.37	$ 26.83	$ 19.46	$ (0.77)	$ 11.41	$ 12.29

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 $0.3 million in Q1/2017.

For the remainder 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 approximately US$47/bbl and upside participation to approximately US$59/bbl. We have also entered into hedges on approximately 38% of our net WCS differential exposure and 60% of our net natural gas exposure.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q1/2017 financial statements.

Conclusion

We are extremely pleased with our sequential quarterly growth in production and funds from operations. The combination of increased activity levels and operational execution are generating impressive results across our portfolio. Our acquisition in Peace River is being successfully integrated, with production on these assets increasing and operating cost improvements underway. And I am pleased to see our organic growth rate increasing – now targeted at 5-6% exit rate 2017 to exit rate 2016, up from a 3-4% growth rate at the time our budget was announced last December. These first quarter results demonstrate our ability to generate strong funds from operations and grow production in today's crude oil pricing environment.

We look forward to executing our plans for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,

Edward D. LaFehr
President & Chief Executive Officer
May 4, 2017

MANAGEMENT'S DISCUSSIONS AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2017. This information is provided as of May 4, 2017. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months ended March 31, 2017 ("Q1/2017") have been compared with the results for the three months ended March 31, 2016 ("Q1/2016"). This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three months ended March 31, 2017, its audited comparative consolidated financial statements for the years ended December 31, 2016 and 2015, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2016. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, 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, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by GAAP. While funds from operations, net debt, operating netback and EBITDA are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers. We believe that the presentation of these non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze against prior periods on a comparable basis.

Funds from Operations

We consider funds from operations ("FFO") a key measure that provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investments, debt repayment and potential future dividends. We believe that this measure provides a meaningful assessment of our operations by eliminating certain non-cash charges. However, funds from operations should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income (loss).

The following table reconciles cash flow from operating activities to funds from operations.

	Three Months Ended March 31	
($ thousands)	2017	2016
Cash flow from operating activities	$ 80,732	$ 64,353
Change in non-cash working capital	(4,790)	(20,409)
Asset retirement expenditures	5,427	1,701
Funds from operations	$ 81,369	$ 45,645

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity.

The following table summarizes our calculation of net debt.

($ thousands)		March 31, 2017		December 31, 2016
Bank loan[1]	$	259,966	$	191,286
Long-term notes[1]		1,574,116		1,584,158
Working capital deficiency (surplus)[2]		16,827		(1,903)
Net debt	$	1,850,909	$	1,773,541

(1) Principal amount of instruments expressed in Canadian dollars.

(2) Working capital is current assets less current liabilities (excluding current financial derivatives and onerous contracts).

Operating Netback

We define operating netback as petroleum and natural gas revenue, less blending expense, royalties, operating expense and transportation expense. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in assessing our ability to generate cash margin on a unit of production basis. Our heavy oil operations require us to purchase diluent for blending that is recovered in the sales price of the blended product. Our purchases and sales of blending diluent are recorded as heavy oil blending expense and revenue. We reduce the petroleum and natural gas revenues by the blending expense in order to calculate our heavy oil sales to compare our realized price to the benchmark price.

	Three Months Ended March 31			
($ thousands)		2017		2016
Petroleum and natural gas revenues	$	260,549	$	153,598
Less: Blending expense		(10,057)		(2,359)
Petroleum and natural gas revenues, net of blending expense		250,492		151,239
Royalties		57,177		34,582
Operating expense		64,130		69,680
Transportation expense		8,042		6,775
Operating netback		121,143		40,202
Realized financial derivatives gain		274		44,626
Operating netback after realized financial derivatives gain	$	121,417	$	84,828

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants. The following table reconciles net income to Bank EBITDA.

	Three Months Ended March 31	
($ thousands)	2017	2016
Net income	$ 11,096	$ 607
Plus:		
Financing and interest	28,506	29,053
Unrealized foreign exchange gain	(11,338)	(86,801)
Unrealized financial derivatives loss	(35,614)	30,123
Current income tax recovery	(736)	(1,442)
Deferred income tax recovery	(12,445)	(48,122)
Depletion and depreciation	122,331	141,671
Disposition of oil and gas properties loss	–	22
Non-cash items(1)	5,871	5,903
Bank EBITDA	$ 107,671	$ 71,014

(1) Non-cash items include share-based compensation, exploration and evaluation expense and non-cash other expense.

FIRST QUARTER HIGHLIGHTS

During Q1/2017, we closed a $66 million asset acquisition in Peace River, initiated an active Canadian drilling program and increased the pace of development on our Eagle Ford properties. Production for Q1/2017 averaged 69,298 boe/d up 6% from Q4/2016 as a result of the acquisition and increased capital activity. In Canada, our capital activities were focused on our Peace River and Lloydminster properties where we drilled 17 net operated wells during Q1/2017 after having limited activity on these lands in 2015 and 2016. In the Eagle Ford, we increased our rig activity at the end of 2016 and kept this development pace through Q1/2017, averaging five drilling rigs and two frac crews on our lands, resulting in 36 (8.4 net) wells drilled.

Production of 69,298 boe/d for Q1/2017 is on the high end of our original 2017 annual guidance of 66,000 - 70,000 boe/d. Strong well results in the Eagle Ford and initial new well production from our Canadian capital program, combined with reactivations on the acquired Peace River properties contributed to higher Q1/2017 production. In the U.S., production increased 8% from Q4/2016 to average 36,081 boe/d in Q1/2017. The increased pace of development at the end of Q4/2016 and strong Q1/2017 well results from completion programs with increased frac stages and higher proppant usage contributed to the Q1/2017 increase in production from Q4/2016. In Canada, production averaged 33,217 boe/d for Q1/2017, an increase of 5% from 31,704 boe/d in Q4/2016. We have had strong drilling results in both Peace River and Lloydminster during the quarter. We also closed the Peace River asset acquisition on January 20, 2017 and were able to reactivate a portion of wells during the quarter which contributed to the increase in production.

Oil prices improved following the Organization of the Petroleum Exporting Countries (“OPEC”) announcement on November 30, 2016 which resulted in WTI oil prices rising above US$50/bbl. WTI averaged US$51.91/bbl during Q1/2017 compared to US$33.45/bbl in Q1/2016, an increase of 55% from the previous period. Natural gas prices also increased compared to Q1/2016 with AECO increasing 39% to $2.94/mcf in Q1/2017 from $2.11/mcf in Q1/2016 and NYMEX increasing 59% to US$3.32/mmbtu in Q1/2017 from US$2.09/mmbtu in Q1/2016. The improvement in commodity prices during Q1/2017 increased our realized sales price to $40.16/boe from $21.93/boe in Q1/2016.

We have placed an added emphasis on lowering our overall cost structure due to the challenging commodity prices in recent years. In the Eagle Ford, expenditures to drill, complete and equip our wells continue to decrease and we averaged approximately US$4.5 million per well in Q1/2017, as compared to US$5.6 million per well in Q1/2016. We are also experiencing cost savings on our Canadian capital program with costs to drill and equip wells in Peace

River down approximately 11% to $2.5 million compared to wells we drilled in Q3/2015. Similarly, in Lloydminster we are seeing cost savings with average well costs down 21% in Q1/2017 to $0.8 million compared to wells we drilled in Q3/2015. We are also achieving greater efficiencies in Lloydminster by applying our multi-lateral drilling and production techniques adopted from our Peace River area with initial results indicating a 25% improvement in individual well capital efficiencies as compared to single lateral horizontal wells.

For Q1/2017, our FFO totaled $81.4 million with capital expenditures of $96.6 million. We generated FFO of $81.4 million ($0.35 per basic share) during Q1/2017 compared to $45.6 million ($0.22 per basic share) in Q1/2016. The increase in FFO is due to higher realized pricing partially offset by lower production volumes and lower realized hedging gains. For 2017, we continue to target annual capital expenditures that approximate FFO in order to minimize additional bank borrowings.

As at March 31, 2017 our net debt was $1.85 billion, as compared to $1.78 billion at December 31, 2016. The net debt increased as we closed the Peace River acquisition in January 2017, which was funded by the $115 million equity issuance in December 2016. At March 31, 2017, we were in compliance with all of our financial covenants with approximately $506 million of undrawn credit capacity.

RESULTS OF OPERATIONS

The Canadian division includes the heavy oil assets in Peace River and Lloydminster and the conventional oil and natural gas assets in Western Canada. The U.S. division includes the Eagle Ford assets in Texas.

Production

	Three Months Ended March 31					
	2017			2016		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**24,625**	**–**	**24,625**	24,807	–	24,807
Light oil and condensate	**1,252**	**20,365**	**21,617**	1,566	22,923	24,489
NGL	**1,099**	**7,207**	**8,306**	1,335	8,774	10,109
Total liquids (bbl/d)	**26,976**	**27,572**	**54,548**	27,708	31,697	59,405
Natural gas (mcf/d)	**37,447**	**51,055**	**88,502**	42,003	56,217	98,220
Total production (boe/d)	**33,217**	**36,081**	**69,298**	34,709	41,067	75,776
Production Mix						
Heavy oil	**74%**	**–%**	**36%**	71%	–%	33%
Light oil and condensate	**4%**	**56%**	**31%**	5%	56%	32%
NGL	**3%**	**20%**	**12%**	4%	21%	13%
Natural gas	**19%**	**24%**	**21%**	20%	23%	22%

Production for Q1/2017 averaged 69,298 boe/d which is on the high end of our original annual guidance range of 66,000 - 70,000 boe/d. Production decreased 9% from Q1/2016 as we had limited capital activity in Canada in 2016 and a slower pace of development on our U.S. assets in 2016. U.S. production averaged 36,081 boe/d in Q1/2017, a 12% decrease from Q1/2016. Despite the year over year decrease, activity in late Q4/2016 increased resulting in five drilling rigs and two frac crews on our lands throughout Q1/2017. This increased activity along with larger fracs and wider spacing of operations increased our Q1/2017 production by 2,649 boe/d from Q4/2016. Canadian production of 33,217 boe/d decreased 4%, or 1,492 boe/d, from Q1/2016. In Q1/2016, we had 7,500 boe/d of low or negative margin heavy oil production shut-in which reduced Q1/2016 production by approximately 5,000 boe/d. In Q1/2017, we closed the Peace River acquisition which contributed approximately 2,700 boe/d to Q1/2017 average production. Without the impact of the shut-in production and the acquisition, Canadian production declined from Q1/2016 to Q1/2017 as we had limited capital activity in Canada throughout 2016.

Commodity Prices

The prices received for our crude oil and natural gas production directly impact our earnings, FFO and our financial position.

Crude Oil

Oil prices were at multi-year lows in 2016 with continued over supply and high inventory levels. In Q1/2016, the price of West Texas Intermediate light oil ("WTI") averaged US$33.45/bbl. Prices stabilized in Q2/2016 and Q3/2016 at approximately US$45/bbl before the OPEC announcement on November 30, 2016 which resulted in WTI oil prices rising above US$50/bbl for the last part of 2016. For Q1/2017, WTI averaged US$51.91/bbl, representing a 55% increase from US$33.45/bbl for Q1/2016.

The discount for Canadian heavy oil is measured by the Western Canadian Select ("WCS") price differential to WTI. For Q1/2017, the WCS heavy oil differential averaged US$14.58/bbl, as compared to US$14.23/bbl for Q1/2016. Over the past year, increased pipeline capacity from Canada to the U.S. Gulf Coast combined with lower overall production levels has helped to stabilize the WCS heavy oil differential.

Natural Gas

Natural gas prices have been driven higher during Q1/2017 compared to Q1/2016, mainly due to higher demand, increased exports to Mexico and increased LNG sales. For Q1/2017, the AECO natural gas price averaged $2.94/mcf, an increase of $0.83/mcf or 39% compared to $2.11/mcf in Q1/2016. The NYMEX natural gas price averaged US$3.32/mmbtu during Q1/2017, representing an increase of US$1.23/mmbtu or 59% compared to US$2.09/mmbtu in Q1/2016. AECO continues to trade at a significant discount to NYMEX due to the oversupply in Western Canada combined with pipeline constraints.

The following tables compare selected benchmark prices and our average realized selling prices for the three months ended March 31, 2017 and 2016.

	Three Months Ended March 31		
	2017	**2016**	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**51.91**	33.45	55%
WTI oil (CAD$/bbl)	**68.68**	45.99	49%
WCS heavy oil (US$/bbl)(2)	**37.34**	19.22	94%
WCS heavy oil (CAD$/bbl)	**49.39**	26.42	87%
LLS oil (US$/bbl)(3)	**52.50**	33.24	58%
LLS oil (CAD$/bbl)	**69.45**	45.70	52%
CAD/USD average exchange rate	**1.3229**	1.3748	(4%)
Edmonton par oil ($/bbl)	**63.98**	40.80	57%
AECO natural gas price ($/mcf)(4)	**2.94**	2.11	39%
NYMEX natural gas price (US$/mmbtu)(5)	**3.32**	2.09	59%

(1) *WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.*
(2) *WCS refers to the average posting price for the benchmark WCS heavy oil.*
(3) *LLS refers to the Argus trade month average for Louisiana Light Sweet oil.*
(4) *AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").*
(5) *NYMEX refers to the NYMEX last day average index price as published by the CGPR.*

	Three Months Ended March 31					
	2017			2016		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Canadian heavy oil ($/bbl)(2)	**$ 35.96**	**$ –**	**$ 35.96**	$ 12.54	$ –	$ 12.54
Light oil and condensate ($/bbl)	**58.05**	**63.58**	**63.26**	35.89	38.11	37.97
NGL ($/bbl)	**30.06**	**25.78**	**26.35**	16.91	18.60	18.38
Natural gas ($/mcf)	**2.64**	**4.17**	**3.52**	1.91	2.76	2.40
Weighted average ($/boe)(2)	**$ 32.81**	**$ 46.93**	**$ 40.16**	$ 13.55	$ 29.02	$ 21.93

(1) *Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.*
(2) *Realized heavy oil prices are calculated based on sales volumes, net of blending costs.*

Average Realized Sales Prices

During Q1/2017, we realized $63.58/bbl for our U.S. light oil and condensate. This was up 67% from $38.11/bbl in Q1/2016 compared to the 52% increase in the LLS benchmark (expressed in Canadian dollars) over the same period. Reduced supply along with increased pipeline capacity has tightened the pricing differential on our U.S. light oil and condensate price to LLS during Q1/2017 compared to Q1/2016 which has increased our realized price more than the benchmark price.

Our realized Canadian light oil and condensate price averaged $58.05/bbl for Q1/2017, as compared to $35.89/bbl for Q1/2016. This represents a $22.16/bbl increase in Q1/2017, and was consistent with the $23.18/bbl increase in the benchmark Edmonton par price over the same period.

In Q1/2017, our realized heavy oil price was $35.96/bbl, a $23.42/bbl increase from Q1/2016. The increase in our realized heavy oil price during Q1/2017 is generally consistent with the increase in the WCS benchmark price (expressed in Canadian dollars) of $22.97/bbl over the same period. Our heavy oil is predominately sold at a fixed dollar differential to the benchmark price. Our realized price increased slightly more than the benchmark due to favourable marketing arrangements in place during Q1/2017.

Our Canadian average realized natural gas price was $2.64/mcf for Q1/2017, up 38% from Q1/2016. The increase in our realized prices during Q1/2017 was consistent with the increase in the AECO benchmark of 39% over the same period.

Our U.S. realized natural gas price was $4.17/mcf for Q1/2017, up 51% from Q1/2016 which is consistent with the increase in the NYMEX benchmark (expressed in Canadian dollars) of 53% over the same period.

For Q1/2017, our realized NGL price was $26.35/bbl or 38% of WTI (expressed in Canadian dollars) compared to $18.38/bbl or 40% of WTI in Q1/2016. The change in our realized price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes.

Gross Revenues

	Three Months Ended March 31					
	2017			2016		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil[(1)]	$ 89,746	$ –	$ 89,746	$ 30,667	$ –	$ 30,667
Light oil and condensate	6,542	116,535	123,077	5,114	79,505	84,619
NGL	2,972	16,724	19,696	2,055	14,849	16,904
Total liquids revenue	99,260	133,259	232,519	37,836	94,354	132,190
Natural gas revenue	8,891	19,139	28,030	7,312	14,096	21,408
Petroleum and natural gas revenue	$ 108,151	$ 152,398	$ 260,549	$ 45,148	$ 108,450	$ 153,598

(1) Heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. The cost of blending diluent is recovered in the sale price of the blended product. Heavy oil revenue includes heavy oil blending revenue.

Total petroleum and natural gas revenues for Q1/2017 of $260.5 million increased $107.0 million or 70% from Q1/2016, due to higher commodity prices being offset by lower production volumes in Q1/2017. Our realized price increased 83% in Q1/2017 to $40.16/boe compared to $21.93 in Q1/2016. This increased petroleum and natural gas revenues by $125.8 million, which was offset by a decrease in production volumes that lowered revenues by $26.5 million. The remainder of the increase is due to higher heavy oil blending revenue associated with the acquisition of the Peace River assets. Petroleum and natural gas revenues of $152.4 million in the U.S. increased $43.9 million from Q1/2016, due to a 62% increase in realized price which was partially offset by a 12% decrease in production. In Canada, petroleum and natural gas revenues for Q1/2017 totaled $108.2 million, a $63.0 million increase compared to Q1/2016 due to a 142% increase in realized price and higher heavy oil blending revenue partially offset by a 4% decrease in production.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues, or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three months ended March 31, 2017 and 2016.

	Three Months Ended March 31					
	2017			2016		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 12,633	$ 44,544	$ 57,177	$ 3,835	$ 30,747	$ 34,582
Average royalty rate[1]	12.9%	29.2%	22.8%	9.0%	28.4%	22.9%
Royalty rate per boe	$ 4.23	$ 13.72	$ 9.17	$ 1.21	$ 8.23	$ 5.02

(1) Average royalty rate excludes sales of heavy oil blending diluents and financial derivatives gain (loss).

The Q1/2017 royalty rate was 22.8% of revenue which was in line with our annual guidance of approximately 23% of revenue. Total royalties for Q1/2017 of $57.2 million increased by $22.6 million or 65%, from Q1/2016, consistent with the 66% increase in oil and natural gas revenues. Overall, the royalty rate has remained relatively unchanged and was 22.8% in Q1/2017 compared to 22.9% in Q1/2016. Canadian royalties, which vary with price, increased to 12.9% of oil and natural gas revenue for Q1/2017 compared to 9.0% of revenue in Q1/2016, primarily due to higher commodity prices. The royalty percentage on our U.S. assets does not vary with price and, as a result, the Q1/2017 U.S. royalty rate of 29.2% has remained fairly consistent with the Q1/2016 rate of 28.4%.

Operating Expense

	Three Months Ended March 31					
	2017			2016		
($ thousands except for per boe)	Canada	U.S.[1]	Total	Canada	U.S.[1]	Total
Operating expense	$ 43,403	$ 20,727	$ 64,130	$ 34,645	$ 35,035	$ 69,680
Operating expense per boe	$ 14.52	$ 6.38	$ 10.28	$ 10.97	$ 9.38	$ 10.11

(1) Operating expense related to the Eagle Ford assets includes transportation expense.

Operating expense was $64.1 million, or $10.28/boe, in Q1/2017 as compared to $69.7 million, or $10.11/boe, in Q1/2016. Operating costs decreased by $5.6 million or 8% in Q1/2017 compared to Q1/2016 due to lower production volumes. Operating expense per boe was $10.28 in Q1/2017 which was below the low end of our guidance range of $11 to $12 per boe. We were below guidance for Q1/2017 as production came in at the high end of our guidance range and we had anticipated closing the Peace River acquisition, which has higher operating costs, prior to January 20, 2017.

In Canada, operating expense increased to $43.4 million or $14.52/boe in Q1/2017. We anticipated costs to increase from Q1/2016 as the acquired Peace River properties have higher operating costs per boe than our other properties. In addition, Q1/2016 operating expense per boe was lower as 7,500 boe/d of high cost, low or negative margin heavy oil production was shut-in for two months in Q1/2016.

U.S. operating expense of $20.7 million for Q1/2017 decreased by $14.3 million compared to Q1/2016. On a per boe basis, operating expense decreased to $6.38/boe in Q1/2017 from $9.38/boe in Q1/2016. In Q1/2016, the operator of the Eagle Ford property changed certain post-production processing arrangements which increased operating expense in the U.S; this was subsequently reversed in Q2/2016. In addition, Q1/2016 included our operated properties in the U.S., which had higher operating costs and were subsequently sold in Q3/2016.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of heavy oil in Canada to pipeline and rail terminals. The following table compares our transportation expense for the three months ended March 31, 2017 and 2016.

	Three Months Ended March 31					
	2017			2016		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Transportation expense	$ 8,042	$ –	$ 8,042	$ 6,775	$ –	$ 6,775
Transportation expense per boe	$ 2.69	$ –	$ 1.29	$ 2.14	$ –	$ 0.98

(1) Transportation expense related to the Eagle Ford assets have been included in operating expenses.

Transportation expense of $1.29/boe for Q1/2017 was in-line with our annual guidance of $1.20 to $1.30 per boe and totaled $8.0 million. Transportation expense increased $1.2 million from Q1/2016 as we had shut-in production in Q1/2016 that had high transportation costs which reduced transportation expense in total and on a per boe basis. This production was brought back online later in 2016 and contributed to the increase in absolute and per boe costs in Q1/2017 compared to Q1/2016.

Blending Expense

Our heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. We purchased blending diluent to reduce the viscosity and record a blending expense. The blending diluent is recovered in the sale of heavy oil. Blending expense for Q1/2017 of $10.1 million increased $7.7 million compared to $2.4 million for Q1/2016. Blending expense increased due to higher volumes of blending diluent being used on the acquired Peace River properties combined with the increase in diluent prices in Q1/2017 compared to Q1/2016. To compare our realized heavy oil sales price against benchmark pricing, we net our heavy oil blending revenue and expense against our heavy oil sales.

Financial Derivatives

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. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price. Changes in the fair value of contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three months ended March 31, 2017 and 2016.

	Three Months Ended March 31		
($ thousands)	2017	2016	Change
Realized financial derivatives gain (loss)			
Crude oil	$ 1,084	$ 41,492	$ (40,408)
Natural gas	(810)	3,134	(3,944)
Total	$ 274	$ 44,626	$ (44,352)
Unrealized financial derivatives gain (loss)			
Crude oil	$ 25,890	$ (34,987)	$ 60,877
Natural gas	9,724	4,864	4,860
Total	$ 35,614	$ (30,123)	$ 65,737
Total financial derivatives gain (loss)			
Crude oil	$ 26,974	$ 6,505	$ 20,469
Natural gas	8,914	7,998	916
Total	$ 35,888	$ 14,503	$ 21,385

The unrealized financial derivatives gain of $35.6 million for Q1/2017 is mainly due to the decrease in commodity price futures at March 31, 2017 as compared to December 31, 2016. At March 31, 2017, the fair value of our financial derivative contracts represent a net asset of $6.5 million compared to a net liability of $29.1 million at December 31, 2016.

For the remainder 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 approximately US$47/bbl and upside participation to approximately US$59/bbl. We have also entered into hedges on approximately 38% of our net WCS differential exposure and 60% of our net natural gas exposure.

Baytex had the following commodity financial derivative contracts as at May 4, 2017.

	Period	Volume	Price/Unit[1]	Index
Oil				
Basis swap	Apr 2017 to Jun 2017	3,000 bbl/d	WTI less US$13.77	WCS
3-way option[2]	Apr 2017 to Dec 2017	14,500 bbl/d	US$58.60/US$47.17/US$37.24	WTI
Basis swap	Apr 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42	WCS
Fixed – Sell	Apr 2017 to Dec 2017	3,500 bbl/d	US$54.46	WTI
Basis swap	Jul 2017 to Sep 2017	4,000 bbl/d	WTI less US$13.98	WCS
3-way option[2]	Jan 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI
Basis swap[3]	Jul 2017 to Sep 2017	2,000 bbl/d	WTI less US$12.63	WCS
Natural Gas				
Fixed – Sell	Apr 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX
Fixed – Sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX
Fixed – Sell	Apr 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO
Fixed – Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO

(1) Based on the weighted average price/unit for the remainder of the contract.

(2) 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$50/US$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives the market price when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.

(3) Contracts entered subsequent to March 31, 2017.

A full description of our financial derivatives can be found in note 17 to the consolidated financial statements.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the periods indicated:

	Three Months Ended March 31					
	2017			2016		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	33,217	36,081	69,298	34,709	41,067	75,776
Operating netback:						
Realized sales price	$ 32.81	$ 46.93	$ 40.16	$ 13.55	$ 29.02	$ 21.93
Less:						
Royalty	4.23	13.72	9.17	1.21	8.23	5.02
Operating expense	14.52	6.38	10.28	10.97	9.38	10.11
Transportation expense	2.69	–	1.29	2.14	–	0.98
Operating netback	$ 11.37	$ 26.83	$ 19.42	$ (0.77)	$ 11.41	$ 5.82
Realized financial derivatives gain	–	–	0.04	–	–	6.47
Operating netback after financial derivatives gain	$ 11.37	$ 26.83	$ 19.46	$ (0.77)	$ 11.41	$ 12.29

Exploration and Evaluation Expense

Exploration and evaluation expense are recorded on the expiry of leases and assessment of our exploration programs and assets and will vary from period to period. Exploration and evaluation expense of $1.3 million for Q1/2017 is consistent with $1.5 million recorded for Q1/2016.

Depletion and Depreciation

	Three Months Ended March 31					
	2017			2016		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation[1]	$ 49,831	$ 71,353	$ 122,331	$ 54,785	$ 86,139	$ 141,671
Depletion and depreciation per boe	$ 16.67	$ 21.97	$ 19.61	$ 17.35	$ 23.05	$ 20.55

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $122.3 million for Q1/2017 decreased by $19.3 million or 14% from Q1/2016 mainly due to lower production volumes in both Canada and the U.S. On a per boe basis, depletion and depreciation expense for Q1/2017 also decreased to $19.61/boe, compared to $20.55/boe for Q1/2016. The depletion rate for Canada has decreased in Q1/2017 compared to Q1/2016 as we recorded $256.6 million of impairments on Canadian oil and gas properties in 2016 which reduced the depletable asset base along with the depletion rate per boe for 2017. In the U.S., the depletion rate has also decreased mainly due to the strengthening of the Canadian dollar against the U.S. dollar from Q1/2016 to Q1/2017 which reduced the Canadian dollar equivalent depletion rate in Q1/2017.

General and Administrative Expense

	Three Months Ended March 31		
($ thousands except for % and per boe)	2017	2016	Change
General and administrative expense	$ 12,583	$ 14,169	(11%)
General and administrative expense per boe	$ 2.02	$ 2.05	(1%)

General and administrative ("G&A") expense for Q1/2017 of $12.6 million or $2.02/boe, was in line with our guidance of approximately $2.00/boe and was $1.6 million or 11% lower than $14.2 million recorded in Q1/2016. The decrease is attributable to cost saving efforts and higher capital recoveries due to increased capital activity in Canada. On a per boe basis, G&A expense of $2.02/boe for Q1/2017 was consistent with $2.05/boe for Q1/2016 as production volumes decreased at a similar rate as G&A expense.

Share-Based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized in net income (loss) over the vesting period of the share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus.

Compensation expense related to the Share Award Incentive Plan was $4.5 million for Q1/2017 and was consistent with $4.4 million recorded in Q1/2016.

Financing and Interest Expense

Financing and interest expense includes interest on our bank loan and long-term notes, non-cash financing costs and the accretion on our asset retirement obligations.

Financing and interest expense decreased to $28.5 million for Q1/2017, compared to $29.1 million in Q1/2016. This decrease relates to lower interest on both our bank loan and U.S. dollar denominated long-term notes. Interest on the bank loan was lower in Q1/2017 as the average bank loan balance was lower during Q1/2017 as compared to Q1/2016. This was largely attributed to the $115 million equity issue completed in December 2016. The Canadian dollar was stronger against the U.S. dollar during Q1/2017 averaging 1.3229 CAD/USD, compared to Q1/2016 when the exchange rate averaged 1.3748 CAD/USD, resulting in a decrease in interest on our long-term notes during Q1/2017.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan are translated to Canadian dollars on the balance sheet date. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in the Canadian operations.

	Three Months Ended March 31		
($ thousands except for % and exchange rates)	**2017**	2016	Change
Unrealized foreign exchange gain	**$ (11,338)**	$ (86,801)	(87%)
Realized foreign exchange loss (gain)	**750**	(542)	(238%)
Foreign exchange gain	**$ (10,588)**	$ (87,343)	(88%)
CAD/USD exchange rates:			
At beginning of period	**1.3427**	1.3840	
At end of period	**1.3322**	1.2971	

We recorded an unrealized foreign exchange gain of $11.3 million for Q1/2017 as the Canadian dollar strengthened against the U.S. dollar with a CAD/USD exchange rate of 1.3322 at March 31, 2017 compared to the exchange rate of 1.3427 at December 31, 2016.

We realized foreign exchange gains from day-to-day U.S. dollar denominated transactions on our Canadian operations of $0.8 million during Q1/2017 compared to gains of $0.5 million for Q1/2016.

Income Taxes

($ thousands)	2017	2016	Change
	Three Months Ended March 31		
Current income tax recovery	$ (736)	$ (1,442)	$ 706
Deferred income tax recovery	(12,445)	(48,122)	35,677
Total income tax recovery	$ (13,181)	$ (49,564)	$ 36,383

Current income tax recovery was $0.7 million for Q1/2017 as compared to $1.4 million for Q1/2016. The recoveries relate to the "carry-back" of losses to prior periods of current income tax expense.

The Q1/2017 deferred income tax recovery of $12.4 million decreased $35.7 million from a recovery of $48.1 million in Q1/2016. The decreased recovery is due to an increase in the value of our financial derivative contracts at Q1/2017 compared to Q1/2016 and an increase in the amount of tax pool claims required to shelter the higher taxable income earned during Q1/2017 compared to Q1/2016.

As previously disclosed in note 15 to the December 31, 2016 consolidated financial statements, we received several reassessments from the Canada Revenue Agency ("CRA") in June 2016. Those reassessments denied $591 million of non-capital loss deductions that we had previously claimed. In September 2016 we filed notices of objection with the CRA appealing each reassessment received and we are now waiting for an appeals officer to be assigned to our file. We remain confident that our original tax filings are correct and we intend to defend those tax filings through the appeals process available to us.

Net Income and Funds from Operations

Net income for Q1/2017 totaled $11.1 million ($0.05 per basic and diluted share) compared to net income of $0.6 million ($0.00 per basic and diluted share) for Q1/2016. Funds from operations for Q1/2017 totaled $81.4 million ($0.35 per basic and $0.34 per diluted share) as compared to $45.6 million ($0.22 per basic and diluted share) for Q1/2016. The components relating to the change in net income and funds from operations from Q1/2016 to Q1/2017 are detailed in the following table:

	Three Months Ended March 31	
($ thousands)	**Net income**	**Funds from operations**
2016	$ **607**	$ **45,645**
Increase (decrease) in revenues		
Revenue, net of royalties	84,356	84,356
(Increase) decrease in expenses		
Operating	5,550	5,550
Transportation	(1,267)	(1,267)
Blending	(7,698)	(7,698)
General and administrative	1,586	1,586
Exploration and evaluation	141	–
Depletion and depreciation	19,340	–
Impairment	–	–
Share-based compensation	(109)	–
Financing and interest	547	1,619
Financial derivatives	21,385	(44,352)
Foreign exchange	(76,755)	(1,292)
Other[(1)(2)]	(204)	(2,072)
Current income tax	(706)	(706)
Deferred income tax	(35,677)	–
2017	$ **11,096**	$ **81,369**

(1) For net income, "other" includes gain (loss) on disposition and other income/expense.

(2) For funds from operations, "other" includes the cash component of other income/expense and payments on onerous contracts.

Other Comprehensive Income (Loss)

Other comprehensive income (loss) is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $18.2 million foreign currency translation loss for Q1/2017 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the strengthening of the Canadian dollar against the U.S. dollar at March 31, 2017 (1.3322 CAD/USD) as compared to December 31, 2016 (1.3427 CAD/USD).

Capital Expenditures

Capital expenditures for the three months ended March 31, 2017 and 2016 are summarized as follows:

	Three Months Ended March 31					
	2017			2016		
($ thousands except for # of wells drilled)	Canada	U.S.	Total	Canada	U.S.	Total
Land	$ 1,277	$ –	$ 1,277	$ 862	$ –	$ 862
Seismic	340	–	340	55	–	55
Drilling, completion and equipping	35,278	55,357	90,635	3,432	69,684	73,116
Facilities	1,589	2,718	4,307	506	7,146	7,652
Total exploration and development	$ 38,484	$ 58,075	$ 96,559	$ 4,855	$ 76,830	$ 81,685
Total acquisitions, net of proceeds from divestitures	66,004	–	66,004	(9)	–	(9)
Total oil and natural gas expenditures	$ 104,488	$ 58,075	$ 162,563	$ 4,846	$ 76,830	$ 81,676
Wells drilled (net)	27.1	8.4	35.5	1.0	12.5	13.5

Q1/2017 capital expenditures totaled $96.6 million as compared to $81.7 million in Q1/2016. We initiated an active drilling program in Canada after deferring all operated heavy oil drilling in 2016. For Q1/2017, we drilled 31 (27.1 net) wells and spent $38.5 million compared to Q1/2016 when we drilled one (1.0 net) wells and spent $4.9 million. In Peace River, we have seen the cost of wells drilled come down approximately 11% compared to wells drilled in Q3/2015. In Lloydminster, we are also seeing cost savings with average well costs down 21% in Q1/2017 to $0.8 million compared to wells drilled in Q3/2015. In addition, in Lloydminster we are achieving greater efficiencies by applying our multi-lateral drilling and production techniques adopted from our Peace River area, with initial results indicating a 25% improvement in individual well capital efficiencies compared to single lateral horizontal wells.

In the U.S., capital spending decreased to $58.1 million in Q1/2017 from $76.8 million in Q1/2016. We drilled 36 (8.4 net) wells in the Eagle Ford in Q1/2017 compared to 44 (12.5 net) wells in Q1/2016. Total costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$4.5 million per well, down 20% from approximately US$5.6 million per well in Q1/2016.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

We regularly review our capital structure and liquidity sources to ensure that our capital resources will be sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures.

We regularly review our exposure to counterparties to ensure they have the financial capacity to honor outstanding obligations to us in the normal course of business and, in certain circumstances, we will seek enhanced credit protection from these counterparties.

The current commodity price environment has reduced our internally generated funds from operations. As a result, we target annual capital expenditures to approximate FFO in order to minimize additional bank borrowings. In 2016, we worked with our lending syndicate to secure our bank credit facilities and restructured the financial covenants applicable to such facilities, which reduced the cost of borrowings and increased our financial flexibility.

If commodity prices decline from current levels, we may need to make changes to our capital program. A sustained low price environment could lead to a default of certain financial covenants, which could impact our ability to borrow under existing credit facilities or obtain new financing. It could also restrict our ability to pay future dividends or sell assets and may result in our debt becoming immediately due and payable. Should our internally generated funds from operations be insufficient to fund the capital expenditures required to maintain operations, we may draw additional funds from our current credit facilities or we may consider seeking additional capital in the form of debt or equity. There is also no certainty that any of the additional sources of capital would be available when required.

At March 31, 2017, net debt was $1,850.9 million, as compared to $1,773.5 million at December 31, 2016, representing an increase of $77.4 million. The increase largely reflects the timing of the Peace River acquisition for $66 million, which was funded by a $115 million equity issuance that closed in December 2016. This was partially offset by the strengthening Canadian dollar against the U.S. dollar at March 31, 2017 compared to December 31, 2016 which reduced the carrying value of our U.S. dollar denominated long-term notes and bank loans.

Bank Loan

Our revolving extendible secured credit facilities are comprised of a US$25 million operating loan and a US$350 million syndicated loan and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants as detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. We may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). The agreement relating to the Revolving Facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts – Credit agreements" on April 13, 2016).

The weighted average interest rate on the credit facilities for Q1/2017 was 3.9%, as compared to 3.5% for Q1/2016.

The following table summarizes the financial covenants contained in our Revolving Facilities and our compliance therewith as at March 31, 2017.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at March 31, 2017**	**March 31, 2017 to March 31, 2018**	**June 30, 2018 to September 30, 2018**	**December 31, 2018**	**Thereafter**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.7:1.00**	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**4.0:1.00**	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at March 31, 2017, our Senior Secured Debt totaled $273 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended March 31, 2017 was $409 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended March 31, 2017 were $102 million.

If we exceed or breach any of the covenants under the Revolving Facilities or our long-term notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to our shareholders.

Long-Term Notes

We have five series of long-term notes outstanding that total $1.57 billion as at March 31, 2017. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at March 31, 2017, the fixed charge coverage ratio was 4.0:1.00.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. As of February 17, 2016, these notes are redeemable at our option, in whole or in part, at specified redemption prices.

On July 19, 2012, we issued $300 million principal amount of senior unsecured notes bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. These notes are redeemable at our option, in whole or in part, commencing on July 19, 2017 at specified redemption prices.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the “2021 Notes”) and US$400 million of 5.625% notes due June 1, 2024 (the “2024 Notes”). The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at our option, in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at specified redemption prices.

Pursuant to the acquisition of Aurora Oil & Gas Limited (“Aurora”), on June 11, 2014, we assumed all of Aurora’s existing senior unsecured notes and then purchased and cancelled approximately 98% of the outstanding notes. As of April 1, 2016, the remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, at specified redemption prices.

Financial Instruments

As part of our normal operations, we are exposed to a number of financial risks, including liquidity risk, credit risk and market risk. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. We manage liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default, resulting in the Company incurring a loss. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is partially mitigated through a series of derivative contracts intended to particularly reduce the volatility in our funds from operations.

A summary of the risk management contracts in place as at March 31, 2017 and the accounting treatment thereof is disclosed in note 17 to the consolidated financial statements.

Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. During the three months ended March 31, 2017, we issued 755,100 common shares pursuant to our share-based compensation program. As at May 4, 2017, we had 234,204,090 common shares and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our funds from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of March 31, 2017 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 142,091**	$ 142,091	$ –	$ –	$ –
Bank loan[(1)(2)]	**259,966**	–	259,966	–	–
Long-term notes[(2)]	**1,574,116**	–	–	741,236	832,880
Interest on long-term notes[(3)]	**390,333**	63,977	127,955	127,316	71,085
Operating leases	**36,888**	8,136	15,097	12,604	1,051
Processing agreements	**47,687**	10,542	10,199	9,032	17,914
Transportation agreements	**57,364**	11,616	24,237	21,511	–
Total	**$ 2,508,445**	$ 236,362	$ 437,454	$ 911,699	$ 922,930

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be repaid on such date.

(2) Principal amount of instruments.

(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at March 31, 2017, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the three months ended March 31, 2017. Further information on our critical accounting policies and estimates can be found in the notes to the annual consolidated financial statements and MD&A for the year ended December 31, 2016.

CHANGES IN ACCOUNTING STANDARDS

We did not adopt any new accounting standards for the three months ended March 31, 2017. A description of accounting standards that will be effective in the future is included in the notes to the audited consolidated financial statements and MD&A for the year ended December 31, 2016.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 “Certification of Disclosure in Issuers’ Annual and Interim Filings”. This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended March 31, 2017.

2017 GUIDANCE

Reflective of our strong first quarter operating results and planned activity level for the balance of the year, we are tightening our 2017 production guidance range to 68,000 to 70,000 boe/d (previously 66,000 to 70,000 boe/d). We are now forecasting full-year 2017 exploration and development capital expenditures of $325 to $350 million (previously $300 to $350 million).

The following table summarizes our 2017 annual guidance and compares it to our Q1/2017 actual results.

	2017 Guidance			
	Original	Revised	Q1/2017	Variance
Exploration and development capital ($ millions)	300 - 350	325 - 350	96.6	N/A
Production (boe/d)	66,000 - 70,000	68,000 - 70,000	69,298	–%
Expenses:				
Royalty rate (%)	~23.0	~23.0	22.8	(1%)
Operating ($/boe)	11.00 - 12.00	11.00 - 12.00	10.28	(7%)
Transportation ($/boe)	1.10 - 1.30	1.10 - 1.30	1.29	–%
General and administrative ($/boe)	~2.00	~2.00	2.02	1%
Interest ($/boe)	~4.00	~4.00	4.04	1%

QUARTERLY FINANCIAL INFORMATION

	2017	2016				2015		
($ thousands, except per common share amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**260,549**	233,116	197,648	195,733	153,598	229,361	265,876	342,802
Net income (loss)	**11,096**	(359,424)	(39,430)	(86,937)	607	(419,175)	(519,247)	(27,096)
Per common share – basic	**0.05**	(1.66)	(0.19)	(0.41)	0.00	(1.99)	(2.50)	(0.13)
Per common share – diluted	**0.05**	(1.66)	(0.19)	(0.41)	0.00	(1.99)	(2.50)	(0.13)
Funds from operations	**81,369**	77,239	72,106	81,261	45,645	93,095	105,052	158,049
Per common share – basic	**0.35**	0.36	0.34	0.39	0.22	0.44	0.51	0.77
Per common share – diluted	**0.34**	0.36	0.34	0.39	0.22	0.44	0.51	0.77
Exploration and development	**96,559**	68,029	39,579	35,490	81,685	140,796	126,804	106,010
Canada	**38,484**	12,151	6,120	2,747	4,855	8,804	33,484	7,690
U.S.	**58,075**	55,878	33,459	32,743	76,830	131,992	93,320	98,320
Acquisitions, net of divestitures	**66,004**	(322)	(62,752)	(37)	(9)	(574)	(498)	1,170
Net debt	**1,850,909**	1,773,541	1,864,022	1,942,538	1,981,343	2,049,905	1,949,736	1,822,511
Total assets	**4,702,423**	4,594,085	4,995,876	5,089,280	5,197,913	5,488,498	5,893,759	6,189,417
Common shares outstanding	**234,203**	233,449	211,542	210,715	210,689	210,583	210,225	206,193
Daily production								
Total production (boe/d)	**69,298**	65,136	67,167	70,031	75,776	81,110	82,170	84,812
Canada (boe/d)	**33,217**	31,704	33,615	31,722	34,709	40,826	43,229	45,264
U.S. (boe/d)	**36,081**	33,432	33,552	38,309	41,067	40,284	38,941	39,548
Benchmark prices								
WTI oil (US$/bbl)	**51.91**	49.29	44.94	45.60	33.45	42.18	46.43	57.94
WCS heavy (US$/bbl)	**37.34**	34.97	31.44	32.29	19.22	27.69	33.13	46.35
CAD/USD avg exchange rate	**1.3229**	1.3339	1.3051	1.2885	1.3748	1.3353	1.3094	1.2294
AECO gas ($/mcf)	**2.94**	2.81	2.20	1.25	2.11	2.65	2.70	2.67
NYMEX gas (US$/mmbtu)	**3.32**	2.98	2.81	1.95	2.09	2.27	2.77	2.64
Sales price ($/boe)	**40.16**	38.16	31.73	30.52	21.93	30.03	34.59	43.34
Royalties ($/boe)	**9.17**	9.28	7.37	6.65	5.02	6.61	7.61	10.10
Operating expense ($/boe)	**10.28**	9.96	9.07	8.67	10.11	9.76	10.25	10.64
Transportation expense ($/boe)	**1.29**	1.30	1.38	0.81	0.98	1.45	1.52	1.94
Operating netback ($/boe)	**19.42**	17.62	13.91	14.39	5.82	12.21	15.21	20.66
Financial derivatives gain ($/boe)	**0.04**	1.62	3.04	3.74	6.47	4.09	3.33	5.19
Operating netback after financial derivatives gain ($/boe)	**19.46**	19.24	16.95	18.13	12.29	16.30	18.54	25.85

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document 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", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; the cost to drill, complete and equip a well in the Eagle Ford, at Peace River and at Lloydminster; our expectation that multi-lateral drilling at Lloydminster will improve individual well capital efficiencies; our target of funding our capital expenditures with funds from operations to minimize additional bank borrowings; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2017; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the percentage of our net exposure to WTI, the WCS differential and natural gas that is hedged for 2017; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the existence, operation and strategy of our risk management program; and our 2017 production and capital expenditure guidance. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves 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.

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash	$ 3,051	$ 2,705
Trade and other receivables	122,213	112,171
Financial derivatives (note 17)	9,529	2,219
	134,793	117,095
Non-current assets		
Financial derivatives (note 17)	2,281	–
Exploration and evaluation assets (note 6)	308,438	308,462
Oil and gas properties (note 7)	4,241,605	4,152,169
Other plant and equipment	15,306	16,359
	$ 4,702,423	$ 4,594,085
LIABILITIES		
Current liabilities		
Trade and other payables	$ 142,091	$ 112,973
Financial derivatives (note 17)	5,343	28,532
Onerous contracts	7,595	9,504
	155,029	151,009
Non-current liabilities		
Bank loan (note 8)	257,156	187,954
Long-term notes (note 9)	1,556,804	1,566,116
Asset retirement obligations (note 10)	395,827	331,517
Deferred income tax liability	361,164	375,695
Financial derivatives (note 17)	–	2,833
	2,725,980	2,615,124
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 11)	4,432,194	4,422,661
Contributed surplus	16,421	21,405
Accumulated other comprehensive income	611,700	629,863
Deficit	(3,083,872)	(3,094,968)
	1,976,443	1,978,961
	$ 4,702,423	$ 4,594,085

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per common share amounts) *(unaudited)*	Three Months Ended March 31 2017	Three Months Ended March 31 2016
Revenue, net of royalties		
Petroleum and natural gas sales	$ 260,549	$ 153,598
Royalties	(57,177)	(34,582)
	203,372	119,016
Expenses		
Operating	64,130	69,680
Transportation	8,042	6,775
Blending	10,057	2,359
General and administrative	12,583	14,169
Exploration and evaluation (note 6)	1,322	1,463
Depletion and depreciation	122,331	141,671
Share-based compensation (note 12)	4,549	4,440
Financing and interest (note 15)	28,506	29,053
Financial derivatives gain (note 17)	(35,888)	(14,503)
Foreign exchange gain (note 16)	(10,588)	(87,343)
Disposition of oil and gas properties loss	–	22
Other expense	413	187
	205,457	167,973
Net income (loss) before income taxes	(2,085)	(48,957)
Income tax (recovery) expense (note 14)		
Current income tax (recovery)	(736)	(1,442)
Deferred income tax (recovery)	(12,445)	(48,122)
	(13,181)	(49,564)
Net income attributable to shareholders	$ 11,096	$ 607
Other comprehensive income (loss)		
Foreign currency translation adjustment	(18,163)	(158,709)
Comprehensive income (loss)	$ (7,067)	$ (158,102)
Net income per common share (note 13)		
Basic	$ 0.05	$ 0.00
Diluted	$ 0.05	$ 0.00
Weighted average common shares (note 13)		
Basic	234,020	210,662
Diluted	236,023	211,606

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2015	$ 4,296,831	$ 22,045	$ 705,382	$ (2,609,784)	**$ 2,414,474**
Vesting of share awards	2,125	(2,125)	–	–	**–**
Share-based compensation	–	4,440	–	–	**4,440**
Comprehensive income (loss) for the period	–	–	(158,709)	607	**(158,102)**
Balance at March 31, 2016	$ 4,298,956	$ 24,360	$ 546,673	$ (2,609,177)	**$ 2,260,812**
Balance at December 31, 2016	$ 4,422,661	$ 21,405	$ 629,863	$ (3,094,968)	**$ 1,978,961**
Vesting of share awards	9,533	(9,533)	–	–	**–**
Share-based compensation	–	4,549	–	–	**4,549**
Comprehensive income (loss) for the period	–	–	(18,163)	11,096	**(7,067)**
Balance at March 31, 2017	$ 4,432,194	$ 16,421	$ 611,700	$ (3,083,872)	**$ 1,976,443**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of Canadian dollars) *(unaudited)*	Three Months Ended March 31 2017	 2016
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income for the period	$ 11,096	$ 607
Adjustments for:		
Share-based compensation (note 12)	4,549	4,440
Unrealized foreign exchange gain (note 16)	(11,338)	(86,801)
Exploration and evaluation (note 6)	1,322	1,463
Depletion and depreciation	122,331	141,671
Non-cash financing and accretion (note 15)	3,314	2,242
Unrealized financial derivatives (gain) loss (note 17)	(35,614)	30,123
Disposition of oil and gas properties loss	–	22
Deferred income tax recovery	(12,445)	(48,122)
Payments on onerous contracts	(1,846)	–
Change in non-cash working capital	4,790	20,409
Asset retirement obligations settled (note 10)	(5,427)	(1,701)
	80,732	64,353
Financing activities		
Increase in bank loan	71,935	50,743
	71,935	50,743
Investing activities		
Additions to exploration and evaluation assets (note 6)	(3,785)	(1,065)
Additions to oil and gas properties (note 7)	(92,774)	(80,620)
Divestitures	80	9
Property acquisition (note 4)	(66,084)	–
Dispositions to other plant and equipment, net of additions	(104)	(322)
Change in non-cash working capital	9,539	(31,235)
	(153,128)	(113,233)
Impact of foreign currency translation on cash balances	807	(1,658)
Change in cash	346	205
Cash, beginning of period	2,705	247
Cash, end of period	$ 3,051	$ 452
Supplementary information		
Interest paid	$ 19,419	$ 21,654
Income taxes paid	$ 486	$ 5,138

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS

For the periods ended March 31, 2017 and 2016

(all tabular amounts in thousands of Canadian dollars, except per common share amounts) (unaudited)

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2016 are available through our filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

2. BASIS OF PRESENTATION

The condensed consolidated interim unaudited financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards and should be read in conjunction with the annual audited consolidated financial statements as at and for the year ended December 31, 2016. The Company's accounting policies are unchanged compared to December 31, 2016. The use of estimates and judgments is also consistent with the December 31, 2016 consolidated financial statements.

The condensed consolidated interim unaudited financial statements were approved by the Board of Directors of Baytex on May 4, 2017.

The consolidated financial statements have been prepared on a historical cost basis, except for derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated. Prior period financial statement amounts have been reclassified to conform with current period presentation.

3. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Revenue from Contracts with Customers

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which will replace IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The standard also requires extensive new disclosures, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 15 will be applied by Baytex on January 1, 2018. The Company is currently in the process of identifying and reviewing its various revenue streams and underlying contracts and assessing the impact on the consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9 *Financial Instruments* which is intended to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. The Company currently does not apply hedge accounting to its derivative contracts nor does it intend to apply hedge accounting upon adoption of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 9 will be applied by Baytex on January 1, 2018. The Company is currently evaluating its impact on the consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income (loss). The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. IFRS 16 will be applied by Baytex on January 1, 2019. The Company is currently evaluating the impact of the standard on the consolidated financial statements.

4. PROPERTY ACQUISITION

On January 20, 2017, Baytex acquired heavy oil properties in the Peace River area of Alberta for total consideration of $66.1 million. The acquisition provides additional development opportunities and the acquired properties are located immediately adjacent to Baytex's existing Peace River lands. The estimated fair value of the oil and gas properties acquired was determined using internal estimates. The asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment, restoration and reclamation of the wells and facilities acquired using a market discount rate of 12%. The property acquisition has been preliminarily accounted for as a business combination under IFRS, as Baytex met the criteria of acquiring inputs and processes to convert those inputs into beneficial outputs. The fair value of the assets acquired and liabilities assumed at the date of acquisition are summarized below:

Consideration for the acquisition:	
Cash paid	$ 66,084
Total consideration	**$ 66,084**
Allocation of purchase price:	
Oil and gas properties	$ 89,526
Crude oil inventory(1)	988
Trade and other payables	(5,400)
Asset retirement obligations	(19,030)
Total net assets acquired	**$ 66,084**

(1) Crude oil inventory is included as part of trade and other receivables.

For the period from January 20, 2017 to March 31, 2017, the acquired properties contributed revenues, net of royalties, of $10.4 million and operating income (revenues, net of royalties, less operating, transportation and blending expenses) of $2.8 million.

The fair value of identifiable assets acquired and liabilities assumed are preliminary, pending finalization of reserve evaluation.

5. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the Company's geographic locations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended March 31	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 108,151**	$ 45,148	**$ 152,398**	$ 108,450	**$ –**	$ –	**$ 260,549**	$ 153,598
Royalties	**(12,633)**	(3,835)	**(44,544)**	(30,747)	**–**	–	**(57,177)**	(34,582)
	95,518	41,313	**107,854**	77,703	**–**	–	**203,372**	119,016
Expenses								
Operating	**43,403**	34,645	**20,727**	35,035	**–**	–	**64,130**	69,680
Transportation	**8,042**	6,775	**–**	–	**–**	–	**8,042**	6,775
Blending	**10,057**	2,359	**–**	–	**–**	–	**10,057**	2,359
General and administrative	**–**	–	**–**	–	**12,583**	14,169	**12,583**	14,169
Exploration and evaluation	**1,322**	1,463	**–**	–	**–**	–	**1,322**	1,463
Depletion and depreciation	**49,831**	54,785	**71,353**	86,139	**1,147**	747	**122,331**	141,671
Share-based compensation	**–**	–	**–**	–	**4,549**	4,440	**4,549**	4,440
Financing and interest	**–**	–	**–**	–	**28,506**	29,053	**28,506**	29,053
Financial derivatives gain	**–**	–	**–**	–	**(35,888)**	(14,503)	**(35,888)**	(14,503)
Foreign exchange gain	**–**	–	**–**	–	**(10,588)**	(87,343)	**(10,588)**	(87,343)
Disposition of oil and gas properties loss	**–**	22	**–**	–	**–**	–	**–**	22
Other expense	**–**	–	**–**	–	**413**	187	**413**	187
	112,655	100,049	**92,080**	121,174	**722**	(53,250)	**205,457**	167,973
Net income (loss) before income taxes	**(17,137)**	(58,736)	**15,774**	(43,471)	**(722)**	53,250	**(2,085)**	(48,957)
Income tax (recovery) expense								
Current income tax (recovery) expense	**–**	(1,442)	**(736)**	–	**–**	–	**(736)**	(1,442)
Deferred income tax (recovery) expense	**(4,628)**	(14,734)	**(7,520)**	(28,400)	**(297)**	(4,988)	**(12,445)**	(48,122)
	(4,628)	(16,176)	**(8,256)**	(28,400)	**(297)**	(4,988)	**(13,181)**	(49,564)
Net income (loss)	**$ (12,509)**	$ (42,560)	**$ 24,030**	$ (15,071)	**$ (425)**	$ 58,238	**$ 11,096**	$ 607
Total oil and natural gas capital expenditures[(1)]	**$ 104,488**	$ 4,846	**$ 58,075**	$ 76,830	**$ –**	$ –	**$ 162,563**	$ 81,676

(1) *Includes acquisitions, net of proceeds from divestitures.*

As at	March 31, 2017	December 31, 2016
Canadian assets	**$ 1,758,115**	$ 1,625,546
U.S. assets	**2,923,137**	2,955,965
Corporate assets	**21,171**	12,574
Total consolidated assets	**$ 4,702,423**	$ 4,594,085

6. EXPLORATION AND EVALUATION ASSETS

	March 31, 2017	December 31, 2016
Balance, beginning of period	$ 308,462	$ 578,969
Capital expenditures	3,785	4,716
Property acquisitions	–	102
Impairment	–	(166,617)
Exploration and evaluation expense	(1,322)	(5,976)
Transfer to oil and gas properties	(1,000)	(85,069)
Divestitures	–	(2,455)
Foreign currency translation	(1,487)	(15,208)
Balance, end of period	$ 308,438	$ 308,462

7. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2015	$ 7,584,281	$ (2,910,106)	$ 4,674,175
Capital expenditures	220,067	–	220,067
Property acquisitions	54	–	54
Transferred from exploration and evaluation assets	85,069	–	85,069
Change in asset retirement obligations	35,714	–	35,714
Divestitures	(59,874)	42,959	(16,915)
Impairment	–	(256,559)	(256,559)
Foreign currency translation	(101,274)	15,616	(85,658)
Depletion	–	(503,778)	(503,778)
Balance, December 31, 2016	$ 7,764,037	$ (3,611,868)	$ 4,152,169
Capital expenditures	92,774	–	92,774
Property acquisition (note 4)	89,526	–	89,526
Transferred from exploration and evaluation assets	1,000	–	1,000
Change in asset retirement obligations (note 10)	48,843	–	48,843
Divestitures	(80)	–	(80)
Foreign currency translation	(27,804)	6,361	(21,443)
Depletion	–	(121,184)	(121,184)
Balance, March 31, 2017	$ 7,968,296	$ (3,726,691)	$ 4,241,605

8. BANK LOAN

	March 31, 2017	December 31, 2016
Bank loan – U.S. dollar denominated(1)	$ 227,565	$ 191,286
Bank loan – Canadian dollar denominated	32,401	–
Bank loan – principal	259,966	191,286
Unamortized debt issuance costs	(2,810)	(3,332)
Bank loan	$ 257,156	$ 187,954

(1) U.S. dollar denominated bank loan balance as at March 31, 2017 was US$170.8 million (US$142.5 million at December 31, 2016)

The revolving extendible secured credit facilities are comprised of a US$25 million operating loan and a US$350 million syndicated loan for Baytex and a US$200 million syndicated loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants as detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension of the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year period at any time). Advances (including letters of credit) under the Revolving Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex breaches any of the covenants under the Revolving Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At March 31, 2017, Baytex had $12.8 million of outstanding letters of credit (December 31, 2016 – $12.6 million) under the Revolving Facilities.

At March 31, 2017, Baytex was in compliance with all of the covenants contained in the Revolving Facilities. The following table summarizes the financial covenants contained in the Revolving Facilities and Baytex's compliance therewith as at March 31, 2017.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at March 31, 2017**	**March 31, 2017 to March 31, 2018**	**June 30, 2018 to September 30, 2018**	**December 31, 2018**	**Thereafter**
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**0.7:1.00**	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	**4.0:1.00**	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) *"Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at March 31, 2017, the Company's Senior Secured Debt totaled $273 million.*

(2) *Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended March 31, 2017 was $409 million.*

(3) *Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended March 31, 2017 were $102 million.*

9. LONG-TERM NOTES

	March 31, 2017	December 31, 2016
7.5% notes (US$6,400 – principal) due April 1, 2020	**$ 8,526**	$ 8,593
6.75% notes (US$150,000 – principal) due February 17, 2021	**199,830**	201,405
5.125% notes (US$400,000 – principal) due June 1, 2021	**532,880**	537,080
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**532,880**	537,080
Total long-term notes – principal	**1,574,116**	1,584,158
Unamortized debt issuance costs	**(17,312)**	(18,042)
Total long-term notes – net of unamortized debt issuance costs	**$ 1,556,804**	$ 1,566,116

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Revolving Facilities and long-term notes unless the Company maintains a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 8) to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at March 31, 2017, the fixed charge coverage ratio was 4.0:1.00.

10. ASSET RETIREMENT OBLIGATIONS

	March 31, 2017	December 31, 2016
Balance, beginning of period	$ 331,517	$ 296,002
Liabilities incurred	1,946	5,642
Liabilities settled	(5,427)	(5,616)
Liabilities divested	(1,053)	(10,590)
Property acquisition (note 4)	19,030	–
Accretion	2,184	6,174
Change in estimate(1)	2,681	20,402
Change in discount rate and inflation rate(2)	45,268	20,260
Foreign currency translation	(319)	(757)
Balance, end of period	$ 395,827	$ 331,517

(1) Changes in the estimated costs, the timing of abandonment and reclamation and the status of wells are factors resulting in a change in estimate.

(2) The discount rate and inflation rate at March 31, 2017 are 2.25% and 1.5%, respectively, compared to 2.25% and 1.75% at December 31, 2016. The change in discount rate also reflects a $64 million adjustment related to the business combination in note 4. On acquisition the obligation was discounted at the market rate the adjustment reflects the change to the obligation discounted at the risk free rate.

11. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at March 31, 2017, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meetings of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2015	210,583	$ 4,296,831
Transfer from contributed surplus on vesting and conversion of share awards	958	14,522
Issued for cash	21,908	115,014
Issuance costs, net of tax	–	(3,706)
Balance, December 31, 2016	233,449	$ 4,422,661
Transfer from contributed surplus on vesting and conversion of share awards	754	9,533
Balance, March 31, 2017	234,203	$ 4,432,194

12. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $4.5 million for the three months ended March 31, 2017 ($4.4 million for the three months ended March 31, 2016).

The weighted average fair value of share awards granted during the three months ended March 31, 2017 was $5.77 per restricted and performance award (for the three months ended March 31, 2016, $2.75 per restricted and performance award).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[(1)]	Total number of share awards
Balance, December 31, 2015	**729**	**613**	**1,342**
Granted	1,313	1,583	2,896
Vested and converted to common shares	(450)	(409)	(859)
Forfeited	(84)	(50)	(134)
Balance, December 31, 2016	**1,508**	**1,737**	**3,245**
Granted	1,587	1,524	3,111
Vested and converted to common shares	(346)	(383)	(729)
Forfeited	(14)	(9)	(23)
Balance, March 31, 2017	**2,735**	**2,869**	**5,604**

(1) Based on underlying awards before applying the payout multiplier which can range from 0x to 2x.

13. NET INCOME PER SHARE

Baytex calculates basic income per share based on the net income attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the year.

	Three Months Ended March 31					
	2017			2016		
	Net income	**Common shares *(000s)***	**Net income per share**	Net income	Common shares *(000s)*	Net income per share
Net income – basic	**$ 11,096**	**234,020**	**$ 0.05**	$ 607	210,662	$ 0.00
Dilutive effect of share awards	**–**	**2,003**	**–**	–	944	–
Net income – diluted	**$ 11,096**	**236,023**	**$ 0.05**	$ 607	211,606	$ 0.00

For the three months ended March 31, 2017, 1.2 million share awards were anti-dilutive (March 31, 2016 – 1.1 million share awards).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2017	2016
Net income (loss) before income taxes	**$ (2,085)**	$ (48,957)
Expected income taxes at the statutory rate of 27.00% (2016 – 27.00%)	**(563)**	(13,218)
Increase (decrease) in income tax recovery resulting from:		
Share-based compensation	**1,228**	1,199
Non-taxable portion of foreign exchange (gain) loss	**(1,334)**	(11,143)
Effect of rate adjustments for foreign jurisdictions	**(11,088)**	(15,879)
Effect of change in deferred tax benefit not recognized	**(1,334)**	(11,143)
Other	**(90)**	620
Income tax (recovery)	**$ (13,181)**	$ (49,564)

As disclosed in the December 31, 2016 consolidated financial statements, Baytex received several reassessments from the Canada Revenue Agency ("CRA") in June 2016. Those reassessments denied $591 million of non-capital loss deductions that Baytex had previously claimed. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received and is now waiting for an appeals officer to be assigned to our file. Baytex remains confident that its original tax filings are correct and intend to defend those tax filings through the appeals process available.

15. FINANCING AND INTEREST

	Three Months Ended March 31	
	2017	2016
Interest on bank loan	$ 2,552	$ 3,611
Interest on long-term notes	22,640	23,200
Non-cash financing	1,130	580
Accretion on asset retirement obligations	2,184	1,662
Financing and interest	$ 28,506	$ 29,053

16. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2017	2016
Unrealized foreign exchange gain	$ (11,338)	$ (86,801)
Realized foreign exchange loss (gain)	750	(542)
Foreign exchange gain	$ (10,588)	$ (87,343)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	March 31, 2017	December 31, 2016	March 31, 2017	December 31, 2016
U.S. dollar denominated	US$72,833	US$66,950	US$1,187,707	US$1,197,732

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

	Period	Volume	Price/Unit[1]	Index	Fair Value[3] *($ millions)*
Oil					
Basis swap	Apr 2017 to Jun 2017	3,000 bbl/d	WTI less US$13.77	WCS	$ (0.5)
3-way option[2]	Apr 2017 to Dec 2017	14,500 bbl/d	US$58.60/US$47.17/US$37.24	WTI	$ 2.2
Basis swap	Apr 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42	WCS	$ –
Fixed – Sell	Apr 2017 to Dec 2017	3,500 bbl/d	US$54.46	WTI	$ 3.8
Basis swap	Jul 2017 to Sep 2017	4,000 bbl/d	WTI less US$13.98	WCS	$ (0.2)
3-way option[2]	Jan 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI	$ 2.7
Basis swap[4]	Jul 2017 to Sep 2017	2,000 bbl/d	WTI less US$12.63	WCS	N/A
Natural Gas					
Fixed – Sell	Apr 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX	$ (2.9)
Fixed – Sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX	$ (0.1)
Fixed – Sell	Apr 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO	$ 1.1
Fixed – Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO	$ 0.3
Total					**$ 6.5**
Current asset					$ 9.5
Non-current asset					$ 2.3
Current liability					$ (5.3)

(1) Based on the weighted average price/unit for the remainder of the contract.

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$50/US$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives the market price when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.

(3) Fair values as at March 31, 2017. For the purposes of the table, contracts entered subsequent to March 31, 2017 will have no fair value assigned.

(4) Contracts entered subsequent to March 31, 2017.

Financial derivatives are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income (loss) and comprehensive income (loss):

	Three Months Ended March 31	
	2017	2016
Realized financial derivatives gain	**$ (274)**	$ (44,626)
Unrealized financial derivatives (gain) loss – commodity	**(35,614)**	30,123
Financial derivatives gain	**$ (35,888)**	$ (14,503)

Physical Delivery Contracts

As at March 31, 2017, Baytex had 7,000 bbl/d of physical delivery contracts that were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

Raymond T. Chan
Chairman of the Board
Baytex Energy Corp.

James L. Bowzer[3]
Independent Businessman

John A. Brussa[3][4]
Vice Chairman
Burnet, Duckworth & Palmer LLP

Edward Chwyl[2][3]
Lead Independent Director
Baytex Energy Corp.
Independent Businessman

Trudy M. Curran[1][4]
Independent Businesswoman

Naveen Dargan[1][2]
Independent Businessman

R. E. T. (Rusty) Goepel[4]
Senior Vice President
Raymond James Ltd.

Edward D. LaFehr
President and Chief Executive Officer
Baytex Energy Corp.

Gregory K. Melchin[1][4]
Independent Businessman

Mary Ellen Peters[1][2]
Independent Businesswoman

Dale O. Shwed[3]
President & Chief Executive Officer
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

HEAD OFFICE

Baytex Energy Corp.
Centennial Place, East Tower
2800, 520 – 3rd Avenue SW
Calgary, Alberta T2P 0R3
Toll-free: 1-800-524-5521
T: 587-952-3000
F: 587-952-3001

www.baytexenergy.com

BANKERS

Bank of Nova Scotia
Alberta Treasury Branches
Bank of America
Bank of Montreal
Barclays Bank plc
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
National Bank of Canada
Royal Bank of Canada
Société Générale
The Toronto-Dominion Bank
Union Bank
Wells Fargo Bank

OFFICERS

Edward D. LaFehr
President and Chief Executive Officer

Rodney D. Gray
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

Brian G. Ector
Senior Vice President, Capital Markets
and Public Affairs

Kendall D. Arthur
Vice President, Lloydminster
and Conventional Business Units

Murray J. Desrosiers
Vice President, General Counsel
and Corporate Secretary

Cameron A. Hercus
Vice President, Corporate Development

Ryan M. Johnson
Vice President, Peace River Business Unit

Chad L. Kalmakoff
Vice President, Finance

Gregory A. Sawchenko
Vice President, Land

Gregory M. Zimmerman
Vice President, U.S. Business Unit

AUDITORS

KPMG LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company L.P.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE