BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three months ended March 31, 2017 and 2016
Dated May 4, 2017

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

	Three Months Ended March 31		
($ thousands)	**2017**	2016	Change
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)	—	(1.99)	(2.50)	(0.13)
Per common share - diluted	**0.05**	(1.66)	(0.19)	(0.41)	—	(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
Net blending expense ($/boe)		—	—	—	—	—	—	—
Operating netback ($/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.