BAYTEX
ENERGY CORP.

Q1 REPORT / 2018

PRESS RELEASE

CALGARY, ALBERTA (May 3, 2018) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months ended March 31, 2018 (all amounts are in Canadian dollars unless otherwise noted).

"We successfully executed our first quarter plan which puts us on track to deliver our 2018 guidance. In the Eagle Ford, we achieved record production rates from new wells and our strongest operating netback since 2014. In Canada, we continued to focus on cost and capital efficiency while managing WCS pricing volatility through active hedging, crude-by-rail and operational optimization. With our excellent asset quality and current commodity prices, we are poised to generate significant free cash flow going forward," commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Generated production of 69,522 boe/d (79% oil and NGL) during Q1/2018 and delivered adjusted funds flow of $84 million ($0.36 per basic share).
- Realized an operating netback of $32.48/boe in the Eagle Ford, the strongest since 2014. Our light oil and condensate production in the Eagle Ford received a premium sales price of US$63.16/bbl (WTI plus US$0.29/bbl) given its proximity to Gulf Coast markets.
- Established average 30-day initial gross production rates of approximately 1,750 boe/d per well from 27 (5.5 net) wells in the Eagle Ford that commenced production in the first quarter. This represents an approximate 20% improvement over wells brought on production in 2017.
- Executed our Q1/2018 drilling program in Canada while optimizing operations in the face of volatile heavy oil prices. Our crude by rail volumes expanded by 25% to 6,500 bbl/d in Q1/2018 and to 8,000 bbl/d currently.
- Extended the maturity of our US$575 million revolving credit facilities by one year to June 2020. We maintain strong financial liquidity with the revolving credit facilities approximately 70% undrawn.

	Three Months Ended		
	March 31, 2018	December 31, 2017	March 31, 2017
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*			
Petroleum and natural gas sales	$ **286,067**	$ 303,163	$ 260,549
Adjusted funds flow (1)	**84,255**	105,796	81,369
Per share – basic	**0.36**	0.45	0.35
Per share – diluted	**0.36**	0.44	0.34
Net income (loss)	**(62,722)**	76,038	11,096
Per share – basic	**(0.27)**	0.32	0.05
Per share – diluted	**(0.27)**	0.32	0.05
Exploration and development	**93,534**	90,156	96,559
Acquisitions, net of divestitures	**(2,026)**	(3,937)	66,004
Total oil and natural gas capital expenditures	$ **91,508**	$ 86,219	$ 162,563
Bank loan (2)	$ **212,571**	$ 213,376	$ 259,966
Long-term notes (2)	**1,525,595**	1,489,210	1,574,116
Long-term debt	**1,738,166**	1,702,586	1,834,082
Working capital (surplus) deficiency	**45,213**	31,698	16,827
Net debt (3)	$ **1,783,379**	$ 1,734,284	$ 1,850,909

	Three Months Ended		
	March 31, 2018	December 31, 2017	March 31, 2017
OPERATING			
Daily production			
Heavy oil (bbl/d)	**24,868**	24,945	24,625
Light oil and condensate (bbl/d)	**20,967**	21,229	21,617
NGL (bbl/d)	**9,143**	9,872	8,306
Total oil and NGL (bbl/d)	**54,978**	56,046	54,548
Natural gas (mcf/d)	**87,261**	81,063	88,502
Oil equivalent (boe/d @ 6:1) (4)	**69,522**	69,556	69,298
Benchmark prices			
WTI oil (US$/bbl)	**62.87**	55.40	51.91
WCS heavy oil (US$/bbl)	**38.59**	43.14	37.34
Edmonton par oil ($/bbl)	**72.06**	69.02	63.98
LLS oil (US$/bbl)	**67.07**	60.50	52.50
Baytex average prices (before hedging)			
Heavy oil ($/bbl) (5)	**33.33**	42.03	35.96
Light oil and condensate ($/bbl)	**79.20**	72.64	63.26
NGL ($/bbl)	**26.17**	29.14	26.35
Total oil and NGL ($/bbl)	**49.63**	51.35	45.31
Natural gas ($/mcf)	**2.95**	2.89	3.52
Oil equivalent ($/boe)	**42.96**	44.75	40.16
CAD/USD noon rate at period end	**1.2901**	1.2518	1.3322
CAD/USD average rate for period	**1.2651**	1.2717	1.3229
COMMON SHARE INFORMATION			
TSX			
Share price (Cdn$)			
High	**4.35**	4.59	6.97
Low	**3.01**	2.95	4.02
Close	**3.53**	3.77	4.54
Volume traded (thousands)	**177,572**	195,013	255,645
NYSE			
Share price (US$)			
High	**3.54**	3.61	5.19
Low	**2.37**	2.30	3.01
Close	**2.74**	3.00	3.65
Volume traded (thousands)	**118,236**	113,647	136,666
Common shares outstanding (thousands)	**236,578**	235,451	234,203

Notes:

(1) Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months ended March 31, 2018.

(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) We include the cost of blending diluent when calculating our realized heavy oil price.

Operating Results

Our operating results for the first quarter of 2018 were consistent with our expectations as we continued to deliver on our operational and financial targets. We successfully executed our first quarter drilling program and continued to drive cost and capital efficiency in our business. In addition, we optimized our heavy oil operations in the face of volatile heavy oil prices by curtailing production where appropriate, building crude inventory and deferring several completions until after spring break-up.

Production averaged 69,522 boe/d (79% oil and NGL) in Q1/2018, as compared to 69,556 boe/d (81% oil and NGL) in Q4/2017. Capital expenditures for exploration and development activities totaled $94 million in Q1/2018 and included the drilling of 55 (29.8 net) crude oil wells, one (1.0 net) natural gas well and six (6.0 net) stratigraphic and service wells with a 100% success rate. During the first quarter, our operating, transportation and general and administrative expenses totaled $13.65/boe, 3% below the mid-point of our annual guidance.

Our 2018 production guidance range is unchanged at 68,000 to 72,000 boe/d with budgeted exploration and development capital expenditures of $325 to $375 million.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The asset generates the highest cash netbacks in our portfolio and contains a significant inventory of development prospects. In Q1/2018, we allocated 45% of our exploration and development expenditures to this asset.

Production averaged 36,017 boe/d (78% oil and NGL) during the first quarter, as compared to 37,362 boe/d in Q4/2017. The reduced volumes reflect the timing of completion activity.

We continue to see strong well performance driven by enhanced completions in Karnes County. In addition, early results from Atascosa County are encouraging as we exploit the oil window on the western portion of our lands. In Q1/2018, we participated in the drilling of 25 (6.9 net) wells and commenced production from 27 (5.5 net) wells. The wells that have been on production for more than 30 days established 30-day initial production rates of approximately 1,750 boe/d, which represents an approximate 20% improvement over wells brought on production in 2017. These wells were completed with approximately 29 effective frac stages per well (compared to 23 in 2015) and proppant per completed foot of approximately 2,100 pounds (compared to 1,100 pounds in 2015).

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, we are able to generate some of the strongest capital efficiencies in the oil and gas industry.

Production averaged 16,500 boe/d (90% heavy oil) during the first quarter, as compared to 16,700 boe/d in Q4/2017. We drilled three (3.0 net) wells in Q1/2018. Our two multi-lateral horizontal wells at Reno averaged 19,255 metres of horizontal length and our first multi-lateral horizontal well on our northern Seal acreage (acquired in January 2017) was successfully drilled at 15,867 metres of horizontal length. These wells are expected to be brought on-stream during the second quarter.

Lloydminster

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

Production averaged 10,000 boe/d (99% heavy oil) during the first quarter as compared to 9,600 boe/d in Q4/2017. We drilled 27 (19.9 net) crude oil wells and six (6.0) stratigraphic and service wells in Q1/2018. During the first quarter, four operated wells drilled in late 2017 established an average 30-day initial production rate of approximately 200 bbl/d per well. In addition, we completed the drilling of three (3.0 net) SAGD well pairs at our Kerrobert thermal project. Production at Kerrobert averaged 700 boe/d in Q1/2018 and we expect to exit 2018 producing approximately 2,000 boe/d.

Financial Review

We generated adjusted funds flow of $84 million ($0.36 per basic share) in Q1/2018, compared to $106 million ($0.45 per basic share) in Q4/2017 and $81 million ($0.35 per basic share) in Q1/2017. The reduction in adjusted funds flow relative to the fourth quarter is largely attributable to wider heavy oil differentials, which resulted in lower price realizations for our Canadian production, and realized financial derivatives losses.

Excluding realized financial derivatives gains and losses, adjusted funds flow in Q1/2018 was $94 million, compared to $104 million in Q4/2017. Despite the wide heavy oil differentials experienced during the first quarter, this represents the second highest quarterly adjusted funds flow (unhedged) since mid-2015 and demonstrates the benefit of our diversified asset portfolio.

Financial Liquidity

We maintain strong financial liquidity with our US$575 million revolving credit facilities approximately 70% undrawn and our first long-term note maturity not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our adjusted funds flow, we expect this liquidity position to be stable going forward.

On April 25, 2018, we extended the maturity of our revolving credit facilities by one year to June 2020. These facilities are covenant-based and do not require annual or semi-annual reviews. We have also elected to end the covenant relief period that was set to expire on December 31, 2018 to benefit from reduced borrowing costs. We are well within the revised financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at March 31, 2018 was 0.5:1.0, compared to a maximum permitted ratio of 3.5:1.0, and our interest coverage ratio was 4.6:1.0, compared to a minimum required ratio of 2.0:1.0.

Our net debt totaled $1.78 billion at March 31, 2018, which is down from $1.85 billion at March 31, 2017.

Operating Netback

Our Q1/2018 operating netback of $20.71/boe (excluding financial derivatives) demonstrates the strength of our diversified asset portfolio. During the first quarter, we benefited from continued strong liquids pricing in the Eagle Ford, which was offset by the recent volatility in heavy oil price realizations in Canada. The Eagle Ford generated an operating netback of $32.48/boe during Q1/2018 while our Canadian operations generated an operating netback of $8.04/boe.

In Q1/2018, the price for West Texas Intermediate light oil ("WTI") averaged US$62.87/bbl, as compared to US$51.91/bbl in Q1/2017. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, widened during Q1/2018 to US$24.28/bbl, as compared to US$14.57/bbl in Q1/2017. Subsequent to quarter-end, the WCS price differential has improved with the May Index averaging US$16.92/bbl.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the Louisiana Light Sweet ("LLS") crude oil benchmark, which is a function of the Brent price. As a result, we benefit from a widening of the Brent-WTI spread. In addition, increased competition for physical field supplies has resulted in improved price realizations relative to LLS. During the first quarter, our light oil and condensate price in the Eagle Ford of US$63.16/bbl (or $79.90/bbl) represented a US$0.29/bbl premium to WTI and a US$3.91/bbl discount to LLS.

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

	Three Months Ended March 31					
	2018			2017		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Sales volume (boe/d)	**33,505**	**36,017**	**69,522**	33,217	36,081	69,298
Realized sales price	**$ 29.69**	**$ 55.30**	**$ 42.96**	$ 32.81	$ 46.93	$ 40.16
Less:						
Royalties	**3.76**	**16.51**	**10.36**	4.23	13.72	9.17
Operating expense	**15.06**	**6.31**	**10.53**	14.52	6.38	10.28
Transportation expense	**2.83**	**—**	**1.36**	2.69	—	1.29
Operating netback	**$ 8.04**	**$ 32.48**	**$ 20.71**	$ 11.37	$ 26.83	$ 19.42
Realized financial derivatives (loss) gain	**—**	**—**	**(1.57)**	—	—	0.04
Operating netback after financial derivatives gain	**$ 8.04**	**$ 32.48**	**$ 19.14**	$ 11.37	$ 26.83	$ 19.46

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 adjusted funds flow. We realized a financial derivatives loss of $10 million in Q1/2018 due to the increased price of crude oil relative to the prices set in our contracts.

For the balance of 2018, we have entered into hedges on approximately 55% of our net crude oil exposure. This includes 45% of our net WTI exposure with 39% fixed at US$52.31/bbl and 6% hedged utilizing a 3-way option structure that provides us with downside price protection at US$54.40/bbl and upside participation to US$60.00/bbl. In addition, we have entered into a Brent-based hedge for 4,000 bbl/d at US$61.31/bbl. We have also entered into hedges on approximately 36% of our net WCS differential exposure at a price differential to WTI of US$14.43/bbl and 30% of our net natural gas exposure through a combination of AECO swaps at C$2.82/mcf and NYMEX swaps at US$3.01/mmbtu.

For 2019, we have entered into hedges on approximately 15% of our net crude oil exposure. This includes 13% of our net WTI exposure with 8% fixed at US$61.99/bbl and 5% hedged utilizing a 3-way option structure that provides us with downside price protection at US$60.00/bbl and upside participation to US$70.00/bbl. In addition, we have entered into a Brent-based 3-way option structure for 1,000 bbl/d that provides us with downside price protection at US$65.50/bbl and upside participation to US$75.50/bbl.

As part of our risk management program, we also transport crude oil to markets by rail when economics warrant. In Q1/2018, we delivered 6,500 bbl/d (approximately 25%) of our heavy oil volumes to market by rail, up from 5,000 bbl/d in 2017. We have secured additional rail capacity, which will see our crude oil volumes delivered to market by rail increase to approximately 8,000 bbl/d in Q2/2018.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q1/2018 financial statements.

2018 Guidance

The following table summarizes our 2018 annual guidance and compares it to our Q1/2018 actual results.

	Guidance (1)	Q1/2018	Variance
Exploration and development capital ($ millions)	325 - 375	93.5	-%
Production (boe/d)	68,000 - 72,000	69,522	-%
Expenses:			
Royalty rate (%)	~ 23.0	24.1	1%
Operating ($/boe)	10.50 - 11.25	10.53	-%
Transportation ($/boe)	1.35 - 1.45	1.36	-%
General and administrative ($ millions)	~ 44 (1.72/boe)	11.0 (1.76/boe)	-%
Interest ($ millions)	~ 100 (3.95/boe)	24.5 (3.92/boe)	(2)%

Note:

(1) As announced on December 7, 2017.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we expect to generate significant free cash flow going forward; our 2018 production and capital expenditure guidance; our Eagle Ford assets, including our assessment that: it is a premier oil resource play, generates our highest cash netbacks and has a significant development inventory; that we can generate some of the strongest capital efficiencies in the oil and gas industry at our Peace River assets; initial production rates from new wells; our expected exit production for 2018 at our Kerrobert thermal project; our strategy to target capital expenditures at a level that approximates our adjusted funds flow; our belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our anticipated 2018 and 2019 oil and natural gas production that is hedged; the volume of oil that we expect to deliver to market by railways in Q2/2018; and our expected royalty rate and operating, transportation, general and administration and interest expenses for 2018. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials; the availability and 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; availability and cost of gathering, processing and pipeline systems; public perception and its influence on the regulatory regime; 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; 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 oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2017, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

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

Non-GAAP Financial and Capital Management Measures

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2017.

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 petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

Advisory Regarding Oil and Gas Information

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

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

MANAGEMENT'S DISCUSSION 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, 2018. This information is provided as of May 3, 2018. 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, 2018 ("Q1/2018") have been compared with the results for the three months ended March 31, 2017 ("Q1/2017"). This MD&A should be read in conjunction with the Company's condensed consolidated interim unaudited financial statements ("consolidated financial statements") for the three months ended March 31, 2018, its audited comparative consolidated financial statements for the years ended December 31, 2017 and 2016, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2017. 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, 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 along with certain measures which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). We refer you to the end of the MD&A for our advisory on forward-looking information and statements and a summary of our non-GAAP measures.

FIRST QUARTER HIGHLIGHTS

Baytex delivered solid operating and financial results for Q1/2018, generating adjusted funds flow of $84.3 million while investing $93.5 million on exploration and development expenditures. Strong well performance in the U.S. and Canada resulted in average production of 69,522 boe/d which approximates the mid-point of our annual guidance range of 68,000 - 72,000 boe/d.

Daily production of 69,522 boe/d for Q1/2018 was consistent with Q4/2017 production of 69,556 boe/d and was slightly higher than 69,298 boe/d reported for Q1/2017. In the U.S., enhanced completion techniques continue to drive strong well performance while the timing of completion activity resulted in U.S. daily production that was slightly lower during Q1/2018 relative to Q4/2017. In Canada, our capital programs at Lloydminster and Peace River continue to deliver strong initial production results and contributed to slightly higher daily production for our Canadian operations in Q1/2018 as compared to Q4/2017.

Our capital program in Canada was focused on our Peace River and Lloydminster properties with a total of $51.5 million invested on exploration and development during Q1/2018. We drilled three (3.0 net) wells at Peace River and 33 (25.9 net) wells at Lloydminster during Q1/2018. Drilling activity at Lloydminster included three (3.0 net) well pairs and facility construction costs for steam-assisted gravity drainage ("SAGD") operations at our Kerrobert thermal project. Our Canadian capital program for Q1/2018 included $9.4 million for the construction of a gas plant and strategic infrastructure to support growth at Peace River.

In the U.S., we invested $42.0 million on development activity during Q1/2018 and drilled 25 (6.9 net) wells and commenced production from 27 (5.5 net) wells. Drilling and completion activity was lower in Q1/2018 relative to Q1/2017 as the operator of our Eagle Ford properties focused development activity on lands where we have a lower working interest. Despite the lower activity in Q1/2018, strong well performance from enhanced completions techniques utilizing higher proppant loading and increased frac stages resulted in U.S. production of 36,017 boe/d for Q1/2018 which is consistent with Q1/2017. U.S. production for Q1/2018 was lower than 37,362 boe/d reported for Q4/2017 due to the timing of completion activity on our lands.

During Q1/2018, strengthening global oil demand along with ongoing compliance with production curtailments by the Organization of Petroleum Exporting Countries ("OPEC") resulted in further reductions in global crude oil inventories. The West Texas Intermediate ("WTI") benchmark oil price averaged US$62.87/bbl for Q1/2018 which is an increase of 21% from US$51.91/bbl for Q1/2017. Pipeline outages in late 2017 compounded existing transportation bottlenecks for heavy grades of Canadian crude oil and resulted in a widening of the price differential for Canadian heavy oil relative to WTI from US$14.57/bbl in Q1/2017 to US$24.28/bbl in Q1/2018. The improvement in light oil market prices has been largely offset by wider heavy oil differentials in Canada resulting in an increase in our realized sales price to $42.96/boe in Q1/2018 from $40.16/boe in Q1/2017.

We generated adjusted funds flow of $84.3 million for the first quarter of 2018, an increase of $2.9 million from adjusted funds flow of $81.4 million reported for Q1/2017. The increase in adjusted funds flow in Q1/2018 was primarily due to higher realized prices which increased $2.80/boe and resulted in a $25.5 million increase in petroleum and natural gas sales relative to Q1/2017. The increase in realized prices for Q1/2018 was partially offset by higher royalties and higher operating, transportation and blending and other expenses, which were $17.1 million higher than Q1/2017. The $8.4 million increase in operating netback was offset by a $10.1 million increase in hedging losses recorded in Q1/2018 as benchmark prices were higher relative to our contract prices in the first quarter of 2018. Corporate costs, including general and administrative expenses and payments on onerous contracts, were $4.6 million lower in Q1/2018 relative to Q1/2017 and contributed to the $2.9 million increase in adjusted funds flow.

At March 31, 2018, net debt was $1,783.4 million, an increase of $49.1 million from $1,734.3 million at December 31, 2017. The increase in net debt is primarily due to the weakening of the Canadian dollar which resulted in a $36.0 million increase in the reported amount of our U.S. dollar denominated debt at March 31, 2018.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended March 31					
	2018			2017		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**24,868**	**—**	**24,868**	24,625	—	24,625
Light oil and condensate	**859**	**20,108**	**20,967**	1,252	20,365	21,617
Natural Gas Liquids ("NGL")	**1,299**	**7,844**	**9,143**	1,099	7,207	8,306
Total liquids (bbl/d)	**27,026**	**27,952**	**54,978**	26,976	27,572	54,548
Natural gas (mcf/d)	**38,873**	**48,388**	**87,261**	37,447	51,055	88,502
Total production (boe/d)	**33,505**	**36,017**	**69,522**	33,217	36,081	69,298
Production Mix						
Heavy oil	**74%**	**—%**	**36%**	74%	—%	36%
Light oil and condensate	**3%**	**56%**	**30%**	4%	56%	31%
NGL	**4%**	**22%**	**13%**	3%	20%	12%
Natural gas	**19%**	**22%**	**21%**	19%	24%	21%

Average production for Q1/2018 was 69,522 boe/d which approximates the mid-point of our annual guidance range of 68,000 - 72,000 boe/d. Our average daily production for Q1/2018 was slightly higher than 69,298 boe/d reported for Q1/2017 due to our successful 2017 capital development program combined with strong well performance in the U.S. and Canada. Higher production in Canada due to strong well performance offset lower production in the U.S. due to the timing of completion activity resulting in production for Q1/2018 that was consistent with 69,556 boe/d reported for Q4/2017. We expect our 2018 production to be within our annual guidance range of 68,000 - 72,000 boe/d.

Production in Canada averaged 33,505 boe/d for Q1/2018 which is slightly higher than average production of 33,217 boe/d reported for Q1/2017 and an increase of 4% from 32,194 boe/d reported for Q4/2017. Strong production results from operated wells brought online at Lloydminster during Q1/2018 contributed to the increase in average daily production from Q4/2017. Positive results from our 2017 Canadian development program have offset natural decline and resulted in slightly higher production for Q1/2018 relative to the comparative period of 2017.

In the U.S., production averaged 36,017 boe/d in Q1/2018 which is consistent with 36,081 boe/d reported for Q1/2017 and down 4% from 37,362 boe/d for Q4/2017. The timing of completion activity during the last two quarters resulted in a decline in average daily production for Q1/2018 relative to Q4/2017. During Q1/2018, we commenced production from 27 (5.5 net) wells as compared to 33 (9.4 net) during Q1/2017. Despite lower completion activity, average daily production for Q1/2018 was consistent with the comparative period of 2017 as a result of strong initial production rates for wells brought online during the first quarter of 2018 due to increased frac stages and higher proppant loading.

Commodity Prices

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

Crude Oil

Global benchmark prices for crude oil have continued to improve in 2018 as global demand growth and sustained compliance with OPEC production curtailments continue to reduce elevated inventory levels. The WTI benchmark oil price is the representative index for inland North American light oil at Cushing, Oklahoma. During Q1/2018, the WTI benchmark price averaged US$62.87/bbl, an increase of 21% from US$51.91/bbl during the first quarter of 2017 and an increase of 13% from US$55.40/bbl during Q4/2017.

Our U.S. crude oil production is primarily priced off the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is the representative benchmark for light oil pricing at the U.S. Gulf coast. Increases in U.S. crude oil exports combined with an increase in global benchmark pricing have increased the premium received for LLS relative to WTI. The LLS benchmark price was US$67.07/bbl representing a US$4.20/bbl premium to WTI for Q1/2018 compared to US$52.50/bbl or a US$0.59/bbl premium to WTI for the same period of 2017.

The price received for our heavy oil sales in Canada is based on the Western Canadian Select ("WCS") benchmark price which trades at a discount to WTI due to the quality and lack of egress for Canadian grades of crude oil. Pipeline outages in late 2017 have compounded existing transportation constraints and have resulted in increased crude inventories in Western Canada and a widening of the WCS heavy oil differential during Q1/2018. The WCS heavy oil differential averaged US$24.28/bbl in Q1/2018 as compared to US$14.57/bbl in Q1/2017. Increased crude by rail volumes will help to mitigate this recent widening of the WCS differential which is now estimated to average approximately US$20/bbl for the remainder of 2018.

Natural Gas

Natural gas prices were lower in Q1/2018 relative to the same period of 2017 as maintenance downtime on pipeline systems in Western Canada during the second half of 2017 created transportation bottlenecks and a lower AECO benchmark relative to Q1/2017. Supply levels in the U.S. increased throughout 2017 which has resulted in a decline in U.S. natural gas benchmark prices in Q1/2018 as compared to early 2017.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. During the first quarter of 2018, the NYMEX natural gas benchmark averaged US$3.00/mmbtu, a decrease of 9% from US$3.32/mmbtu for the same period of 2017.

In Canada, we receive natural gas pricing based on the AECO benchmark which averaged $1.85/mcf during Q1/2018 which is 37% lower than $2.94/mcf during Q1/2017. The AECO benchmark continues to trade at a significant discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production.

The following tables compare selected benchmark prices and our average realized selling prices for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31		
	2018	2017	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	**62.87**	51.91	21 %
WTI oil (CAD$/bbl)	**79.54**	68.68	16 %
WCS heavy oil (US$/bbl)[2]	**38.59**	37.34	3 %
WCS heavy oil (CAD$/bbl)	**48.83**	49.39	(1)%
LLS oil (US$/bbl)[3]	**67.07**	52.50	28 %
LLS oil (CAD$/bbl)	**84.85**	69.45	22 %
CAD/USD average exchange rate	**1.2651**	1.3229	(4)%
Edmonton par oil ($/bbl)	**72.06**	63.98	13 %
AECO natural gas price ($/mcf)[4]	**1.85**	2.94	(37)%
NYMEX natural gas price (US$/mmbtu)[5]	**3.00**	3.32	(9)%

(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					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Heavy oil ($/bbl)(2)	**$ 33.33**	**$ —**	**$ 33.33**	$ 35.96	$ —	$ 35.96
Light oil and condensate ($/bbl)	**62.78**	**79.90**	**79.20**	58.05	63.58	63.26
NGL ($/bbl)	**28.72**	**25.75**	**26.17**	30.06	25.78	26.35
Natural gas ($/mcf)	**1.92**	**3.78**	**2.95**	2.64	4.17	3.52
Weighted average ($/boe)(2)	**$ 29.69**	**$ 55.30**	**$ 42.96**	$ 32.81	$ 46.93	$ 40.16

(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 this table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on sales volumes and sales dollars, net of blending and other expense.

Average Realized Sales Prices

Our weighted average sales price was $42.96/boe for Q1/2018, up $2.80/boe from $40.16/boe reported for the first quarter of 2017. Higher crude oil pricing helped to increase the weighted average sales price for our U.S. production which was partially offset by a lower weighted average sales price received for our production in Canada due to a widening of the WCS heavy oil differential.

In Canada, our realized heavy oil sales price, net of blending and other expense averaged $33.33/bbl which is $2.63/bbl lower than realized pricing of $35.96/bbl for Q1/2017. The decrease in our realized heavy oil sales price for Q1/2018 is primarily a result of an increase in the cost and quantity of blending diluent required for pipeline transportation relative to Q1/2017. Our realized heavy oil price for Q1/2018 was also impacted by a decrease in WCS benchmark pricing (expressed in Canadian dollars) which was $0.56/bbl lower relative to the same period of 2017. Our Canadian heavy oil production requires blending with diluent in order to meet pipeline transportation specifications. The price received for the blended product is recorded as heavy oil sales revenue. We include the cost of blending diluent in our realized heavy oil sales price in order to compare our realized pricing on our produced volumes to the WCS benchmark.

Our realized Canadian light oil and condensate price averaged $62.78/bbl for Q1/2018, an increase of $4.73/bbl from $58.05/bbl for Q1/2017. The price received for Canadian light oil and condensate sales is discounted to benchmark oil prices with adjustments for quality and is net of fees and differentials that do not fluctuate with prices. During Q3/2017, we disposed of certain oil and natural gas properties in our Conventional business unit which produced a higher quality light oil than our remaining Canadian properties. As a result, our realized light oil and condensate price only increased $4.73/bbl relative to an $8.08/bbl increase in Edmonton par pricing for Q1/2018 relative to the same period of 2017.

In the U.S., our realized light oil and condensate price was $79.90/bbl for the first quarter of 2018. This represents an increase of $16.32/bbl from $63.58/bbl reported for Q1/2017, as compared to a $15.40/bbl increase in LLS benchmark (expressed in Canadian dollars) pricing over the same period. Improved contract pricing following the re-negotiation of certain marketing arrangements along with increased pipeline capacity has reduced the pricing differential on our U.S. light oil and condensate realized price relative to the LLS benchmark. These factors more than offset the impact that a stronger Canadian dollar had on the LLS benchmark expressed in Canadian dollars and our realized pricing in Q1/2018 relative to Q1/2017.

For Q1/2018, our realized NGL price was $26.17/bbl or 33% of WTI (expressed in Canadian dollars) compared to $26.35/bbl or 38% of WTI in Q1/2017. Our realized price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products. The decrease in our realized price is consistent with the decrease in the market prices for propane and butane which were lower relative to WTI in Q1/2018 as compared to Q1/2017.

Our realized natural gas price in Canada was $1.92/mcf for Q1/2018 compared to realized pricing of $2.64/mcf in Q1/2017. The decrease is primarily due to lower AECO benchmark pricing in Q1/2018 relative to the comparative period. A portion of our Canadian natural gas sales are referenced to the AECO daily index which was higher throughout Q1/2018 relative to the AECO monthly average index. Accordingly, our realized sales price for Q1/2018 decreased by $0.72/mcf from Q1/2017 relative to a $1.09/mcf decrease in the AECO monthly average over the same periods.

Our U.S. realized natural gas price was $3.78/mcf in Q1/2018, down from $4.17/mcf reported for the first three months of 2017. This represents a decrease of $0.39/mcf which is consistent with the decrease in the NYMEX natural gas benchmark (expressed in Canadian dollars) in Q1/2018 relative to Q1/2017.

Petroleum and Natural Gas Sales

	Three Months Ended March 31					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Heavy oil	**$ 91,883**	**$ —**	**$ 91,883**	$ 89,746	$ —	$ 89,746
Light oil and condensate	**4,851**	**144,607**	**149,458**	6,542	116,535	123,077
NGL	**3,356**	**18,178**	**21,534**	2,972	16,724	19,696
Total liquids sales	**100,090**	**162,785**	**262,875**	99,260	133,259	232,519
Natural gas sales	**6,724**	**16,468**	**23,192**	8,891	19,139	28,030
Total petroleum and natural gas sales	**106,814**	**179,253**	**286,067**	108,151	152,398	260,549
Blending and other expense	**(17,290)**	**—**	**(17,290)**	(10,057)	—	(10,057)
Total sales, net of blending and other expense	**$ 89,524**	**$ 179,253**	**$ 268,777**	$ 98,094	$ 152,398	$ 250,492

Total petroleum and natural gas sales were $286.1 million for Q1/2018, an increase of $25.5 million from $260.5 million reported for Q1/2017. The increase was primarily driven by higher realized pricing in Q1/2018 as production was fairly consistent during Q1/2018 and Q1/2017.

In Canada, petroleum and natural gas sales were $106.8 million for the first quarter of 2018, down 1% from $108.2 million in the same period of 2017. Total sales, net of blending and other expense, decreased as a result of a decline in Canadian benchmark prices which reduced our weighted average realized price by 10% from $32.81/boe in Q1/2017 to $29.69/boe in Q1/2018 combined with an increase in blending and other expense which was $7.2 million higher than Q1/2017. The impact of a lower weighted average realized price was partially offset by higher average daily production of 33,505 boe/d for the first quarter of 2018, which is slightly higher than 33,217 boe/d for the same period of 2017.

Petroleum and natural gas sales of $179.3 million in the U.S. increased 18% or $26.9 million from $152.4 million reported for the first quarter of 2017. The increase was driven by an 18% increase in our weighted average realized price of $55.30/boe for Q1/2018 as compared to $46.93/boe in Q1/2017. Average daily production in the U.S. was 36,017 boe/d in the first quarter of 2018 which is consistent with 36,081 boe/d reported for the comparative period of 2017.

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, 2018 and 2017.

	Three Months Ended March 31					
	2018			2017		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 11,334**	**$ 53,505**	**$ 64,839**	$ 12,633	$ 44,544	$ 57,177
Average royalty rate[1]	**12.7%**	**29.8%**	**24.1%**	12.9%	29.2%	22.8%
Royalty rate per boe	**$ 3.76**	**$ 16.51**	**$ 10.36**	$ 4.23	$ 13.72	$ 9.17

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.

Total royalties for Q1/2018 were $64.8 million and averaged 24.1% of total sales, net of blending and other expense, which is consistent with our 2018 annual guidance of approximately 23%. A higher portion of our petroleum and natural gas sales were from our U.S. operations during Q1/2018, which increases our corporate average royalty rate due to the higher royalty rate on our U.S. acreage relative to our Canadian properties. We have maintained our guidance for our royalty rate of approximately 23%. Our Canadian royalty rate averaged 12.7% of total sales, net of blending and other expense, for Q1/2018 which is consistent with 12.9% for the same period of 2017. In the U.S., royalties for the first quarter of 2018 averaged 29.8% of total sales, net of blending and other expense, which is slightly higher than 29.2% for Q1/2017 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage. Total royalties of $64.8 million for Q1/2018 increased $7.7 million as compared to Q1/2017 due to higher realized pricing in combination with an increase in the portion of total petroleum and natural gas sales coming from our U.S operations.

Operating Expense

	Three Months Ended March 31					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.[(1)]**	**Total**	Canada	U.S.[(1)]	Total
Operating expense	**$ 45,420**	**$ 20,468**	**$ 65,888**	$ 43,403	$ 20,727	$ 64,130
Operating expense per boe	**$ 15.06**	**$ 6.31**	**$ 10.53**	$ 14.52	$ 6.38	$ 10.28

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

Total operating expense was $65.9 million ($10.53/boe) for Q1/2018 as compared to $64.1 million ($10.28/boe) for Q1/2017 and is on the low end of our annual guidance for 2018. We expect operating expense to be within our annual guidance range of $10.50-$11.25/boe for the remainder of 2018.

In Canada, operating expense was $45.4 million ($15.06/boe) for Q1/2018, up $2.0 million or $0.54/boe from $43.4 million ($14.52/boe) for the same period of 2017. Operating expense per boe was slightly higher in Q1/2018 as a result of a slight increase in fuel and electricity costs relative to Q1/2017 in addition to planned repair and maintenance activity completed during the first three months of 2018.

U.S. operating expense of $20.5 million ($6.31/boe) for Q1/2018 was relatively consistent with $20.7 million ($6.38/boe) reported for Q1/2017. The Canadian dollar was stronger relative to the U.S. dollar in Q1/2018 which resulted in a slight decrease in our U.S. operating expense expressed in Canadian dollars compared to the first quarter of 2017.

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, 2018 and 2017.

	Three Months Ended March 31					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.[(1)]**	**Total**	Canada	U.S.[(1)]	Total
Transportation expense	**$ 8,519**	**$ —**	**$ 8,519**	$ 8,042	$ —	$ 8,042
Transportation expense per boe	**$ 2.83**	**$ —**	**$ 1.36**	$ 2.69	$ —	$ 1.29

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

Transportation expense was $8.5 million ($1.36/boe) for Q1/2018 which is consistent with $8.0 million ($1.29/boe) for the comparative quarter of 2017 and on the low end of our annual guidance range of $1.35-$1.45/boe for 2018. Transportation expense will vary from period to period depending on hauling distances to optimize sales prices and trucking rates. We expect transportation expense to be in line with guidance for the remainder of 2018.

Blending and Other Expense

Blending and other expense primarily includes the cost of blending diluent purchased in order to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. We purchase blending diluent to reduce the viscosity and record a blending and other expense. The sales price received for the blended product is recorded as heavy oil sales. Our heavy oil blending and other expense is netted against our heavy oil sales to compare the realized price on our produced volumes to benchmark pricing. Accordingly, our heavy oil sales price realization can fluctuate depending on the quantities and price of blending diluent required to meet pipeline specifications.

Blending and other expense for Q1/2018 was $17.3 million compared to $10.1 million for the first three months of 2017. The $7.2 million increase in blending and other expense during the first quarter of 2018 is due to higher diluent prices combined with an increase in the quantities of diluent required to meet pipeline specifications relative to the same period of 2017. The density of blending diluent available in Q1/2018 was higher relative to Q1/2017 which resulted in higher quantities being used to meet pipeline specifications.

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 adjusted funds flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled 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, 2018 and 2017.

	Three Months Ended March 31		
($ thousands)	**2018**	2017	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (10,265)**	$ 1,084	$ (11,349)
Natural gas	**424**	(810)	1,234
Total	**$ (9,841)**	$ 274	$ (10,115)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (17,659)**	$ 25,890	$ (43,549)
Natural gas	**(50)**	9,724	(9,774)
Total	**$ (17,709)**	$ 35,614	$ (53,323)
Total financial derivatives gain (loss)			
Crude oil	**$ (27,924)**	$ 26,974	$ (54,898)
Natural gas	**374**	8,914	(8,540)
Total	**$ (27,550)**	$ 35,888	$ (63,438)

The realized financial derivatives loss of $9.8 million for Q1/2018 is primarily a result of crude oil market price indexes settling at levels above those set in our fixed price contracts. Realized losses of $10.3 million related to our crude oil financial derivatives in place for Q1/2018 were driven by $16.7 million of losses on 14,000 bbl/d of WTI swap contracts with an average fixed price of US$52.31/bbl and $2.7 million of losses on 4,000 bbl/d of Brent swap contracts with an average fixed price of US$61.31/bbl where the market price of WTI and Brent settled above our contract prices. We also recorded $0.7 million of realized losses on our 3-way option contract as the market price of WTI settled above the sold call price during Q1/2018. Losses on WTI and Brent contracts were partially offset by gains of $9.7 million on 8,000 bbl/d of WCS differential contracts with an average fixed differential of $14.24/bbl as the index was wider than the differentials set in our contracts throughout the first quarter of 2018. During Q1/2018, we recorded realized gains of $0.4 million on our natural gas financial derivatives. These gains were primarily a result of the AECO price index for the first quarter of 2018 averaging lower than the average fixed price of $2.67/GJ on 5,000 GJ/d of AECO contracts in place for Q1/2018.

At March 31, 2018, the fair value of our financial derivative contracts represent a net liability of $49.4 million compared to a net liability of $31.6 million at December 31, 2017. The net liability of $49.4 million as at March 31, 2018 is primarily a result of futures pricing for WTI and Brent crude oil indexes being higher than the prices set in our fixed price crude oil financial derivatives in place for 2018 and 2019.

We had the following commodity financial derivative contracts as at May 3, 2018.

	Period	Volume	Price/Unit(1)	Index
Oil				
Basis swap	Apr 2018 to Jun 2018	2,000 bbl/d	WTI less US$14.23/bbl	WCS
Basis swap	Apr 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS
Basis swap	May 2018 to July 2018	2,000 bbl/d	WTI less US$17.65/bbl	WCS
Fixed - Sell	Apr 2018 to Dec 2018	14,000 bbl/d	US$52.31/bbl	WTI
3-way option (2)	Apr 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI
Fixed - Sell	Apr 2018 to Dec 2018	4,000 bbl/d	US$61.31/bbl	Brent
Fixed - Sell	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI
Swaption (3)	Jan 2019 to Dec 2019	2,000 bbl/d	US$59.60/bbl	WTI
Swaption (3)	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI
3-way option (2)	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI
3-way option (2)	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI
Natural Gas				
Fixed - Sell	Jan 2018 to Dec 2018	15,000 mmbtu/d	US$3.01	NYMEX
Fixed - Sell	Apr 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO

(1) Based on the weighted average price per unit for the period.

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$54.40/US$40 contract, Baytex receives WTI plus US$14.40/bbl when WTI is at or below US$40/bbl; Baytex receives US$54.40/bbl when WTI is between US$40/bbl and US$54.40/bbl; Baytex receives the market price when WTI is between US$54.40/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US $60/bbl.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2018, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**33,505**	**36,017**	**69,522**	33,217	36,081	69,298
Operating netback:						
Total sales, net of blending and other expense	**$ 29.69**	**$ 55.30**	**$ 42.96**	$ 32.81	$ 46.93	$ 40.16
Less:						
Royalties	**3.76**	**16.51**	**10.36**	4.23	13.72	9.17
Operating expenses	**15.06**	**6.31**	**10.53**	14.52	6.38	10.28
Transportation expenses	**2.83**	**—**	**1.36**	2.69	—	1.29
Operating netback	**$ 8.04**	**$ 32.48**	**$ 20.71**	$ 11.37	$ 26.83	$ 19.42
Realized financial derivatives (loss) gain	**—**	**—**	**(1.57)**	—	—	0.04
Operating netback after financial derivatives (loss) gain	**$ 8.04**	**$ 32.48**	**$ 19.14**	$ 11.37	$ 26.83	$ 19.46

Operating netback after financial derivatives decreased by $0.32/boe to $19.14/boe reported for Q1/2018 from $19.46/boe for Q1/2017. The increase in our realized sales price per boe during the first quarter of 2018 was partially offset by higher royalties, operating expenses and transportation expenses compared to the same period of 2017. The increase in royalty expense per boe is due to a higher portion of our petroleum and natural gas sales being generated from our U.S. operations, which has a higher royalty rate than our Canadian operations. Operating expense per boe was slightly higher in Q1/2018 due to slightly higher fuel and electricity costs relative to Q1/2017 along with planned repair and maintenance activity completed during Q1/2018. We recorded realized losses on financial derivatives of $1.57/boe in Q1/2018 as losses recorded on our WTI and Brent contracts were partially offset by gains recorded on our WCS differential and natural gas contracts.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the derecognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of lease expiries, the accumulated costs of expiring leases, and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $2.0 million for Q1/2018 compared to $1.3 million for Q1/2017.

Depletion and Depreciation

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes, and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation(1)	**$ 47,169**	**$ 61,120**	**$ 108,289**	$ 50,978	$ 71,353	$ 122,331
Depletion and depreciation per boe	**$ 15.64**	**$ 18.86**	**$ 17.31**	$ 17.05	$ 21.97	$ 19.61

(1) Canada includes corporate depreciation.

Depletion and depreciation expense was $108.3 million ($17.31/boe) for Q1/2018 compared to $122.3 million ($19.61/boe) reported for Q1/2017. In Canada, depletion expense was lower in Q1/2018 compared to Q1/2017 primarily due to a lower depletion rate from increased reserve volumes in Q1/2018 recognized in Q4/2017. The U.S. depletion rate for 2018 is also lower than the comparative period due to a lower average CAD/USD exchange rate in Q1/2018 relative to Q1/2017 and from increased reserve volumes in Q1/2018 recognized in Q4/2017.

General and Administrative Expense

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs, and administrative recoveries earned for operating capital and production activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated capital and production activity during the period.

The following table summarizes our G&A expense for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31		
($ thousands except for per boe)	**2018**	2017	Change
General and administrative expense	**$ 11,008**	$ 12,583	$ (1,575)
General and administrative expense per boe	**$ 1.76**	$ 2.02	$ (0.26)

We reported G&A expense of $11.0 million or $1.76/boe for the first three months of 2018 compared to $12.6 million or $2.02/boe for the comparative period of 2017. Reduced staffing levels and our ongoing cost savings efforts have resulted in lower G&A expense in Q1/2018 relative to Q1/2017. G&A expense for the first quarter of 2018 was consistent with our annual guidance of approximately $44 million and $1.72/boe and we are maintaining our guidance for the year.

Share-Based Compensation Expense

Share-based compensation ("SBC") expense associated with the Share Award Incentive Plan is recognized in net income or 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. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $3.9 million for Q1/2018 which is down from $4.5 million reported for Q1/2017. SBC expense is lower in 2018 due to a lower fair value assigned to share awards granted in 2018 as compared to awards granted in 2017.

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 varies depending on debt levels outstanding during the period and the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and discount rates used to present value the obligations.

Financing and interest expense was $28.0 million for Q1/2018 which is slightly lower than $28.5 million reported for the same period of 2017. Cash interest expense of $24.5 million for the first three months of 2018 was slightly lower than $25.2 million reported for the same period of 2017 due to lower interest on our long-term notes as a result of a stronger Canadian dollar in Q1/2018 which reduced the amount of U.S. dollar interest reported in Canadian dollars. We are maintaining our full year guidance for cash interest of approximately $100 million and $3.92/boe as the Q1/2018 results are consistent with our expectations.

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 using the closing CAD/USD exchange rate. 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 exchange rates)	**2018**	2017	Change
Unrealized foreign exchange loss (gain)	**$ 36,046**	$ (11,338)	47,384
Realized foreign exchange loss	**171**	750	(579)
Foreign exchange loss (gain)	**$ 36,217**	$ (10,588)	46,805
CAD/USD exchange rates:			
At beginning of period	**1.2518**	1.3427	
At end of period	**1.2901**	1.3322	

We recorded an unrealized foreign exchange loss of $36.0 million for Q1/2018 due to a weakening of the Canadian dollar relative to the U.S. dollar. The CAD/USD exchange rate was 1.2901 as at March 31, 2018 compared to 1.2518 as at December 31, 2017.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $0.2 million for the first quarter of 2018 compared to a loss of $0.8 million for the same period of 2017.

Income Taxes

	Three Months Ended March 31		
($ thousands)	**2018**	2017	Change
Current income tax recovery	**$ (73)**	$ (736)	$ 663
Deferred income tax recovery	**(22,917)**	(12,445)	(10,472)
Total income tax recovery	**$ (22,990)**	$ (13,181)	$ (9,809)

The current income tax recovery was $0.1 million for 2018, as compared to $0.7 million for 2017. Current income taxes were nominal for Q1/2018 and Q1/2017. During both periods tax pool claims were sufficient to shelter the income associated with our adjusted funds flow.

The 2018 deferred income tax recovery of $22.9 million increased $10.5 million from $12.4 million in 2017. The deferred income tax recovery for 2018 is higher compared to 2017 primarily due to higher unrealized losses recorded on our financial derivatives contracts.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments followed a previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

We remain confident that the tax filings of the affected entities are correct and are defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

In September 2016, we filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of the CRA. We are waiting for an Appeals Officer to be assigned to our file, after which we estimate that the appeals process will take up to one year. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the "Losses"). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available to recover taxes paid in the years 2012 through 2015.

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the three months ended March 31, 2018 and 2017 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2018**	2017	Change
Petroleum and natural gas sales	**$ 286,067**	$ 260,549	$ 25,518
Royalties	**(64,839)**	(57,177)	(7,662)
Revenue, net of royalties	**221,228**	203,372	17,856
Expenses			
Operating	**(65,888)**	(64,130)	(1,758)
Transportation	**(8,519)**	(8,042)	(477)
Blending and other	**(17,290)**	(10,057)	(7,233)
Operating netback	**$ 129,531**	$ 121,143	$ 8,388
General and administrative	**(11,008)**	(12,583)	1,575
Cash financing and interest	**(24,511)**	(25,192)	681
Realized financial derivatives (loss) gain	**(9,841)**	274	(10,115)
Realized foreign exchange loss	**(171)**	(750)	579
Other income (expense)	**279**	(413)	692
Current income tax recovery	**73**	736	(663)
Payments on onerous contracts	**(97)**	(1,846)	1,749
Adjusted funds flow	**$ 84,255**	$ 81,369	$ 2,886
Exploration and evaluation	**(2,019)**	(1,322)	(697)
Depletion and depreciation	**(108,289)**	(122,331)	14,042
Share based compensation	**(3,915)**	(4,549)	634
Non-cash financing and accretion	**(3,499)**	(3,314)	(185)
Unrealized financial derivatives (loss) gain	**(17,709)**	35,614	(53,323)
Unrealized foreign exchange (loss) gain	**(36,046)**	11,338	(47,384)
Gain on disposition of oil and gas properties	**1,486**	—	1,486
Deferred income tax recovery	**22,917**	12,445	10,472
Payments on onerous contracts	**97**	1,846	(1,749)
Net income (loss) for the period	**$ (62,722)**	$ 11,096	$ (73,818)

We generated adjusted funds flow of $84.3 million for Q1/2018, an increase of $2.9 million from adjusted funds flow of $81.4 million reported for Q1/2017. The increase in adjusted funds flow in the first quarter of 2018 was primarily due to a higher operating netback which increased by $8.4 million from the same period in 2017. The increase in operating netback was due to higher commodity prices which increased revenues, partially offset by higher royalties and higher operating and transportation expenses. The increase in operating netback was increased by $3.3 million due to lower general and administrative expenses and lower payments on onerous contracts and was offset by a $10.1 million increase in realized hedging losses.

In Q1/2018, we recorded a net loss of $62.7 million compared to income of $11.1 million for the same period of 2017. The net loss recorded for Q1/2018 includes an unrealized loss on financial derivatives of $17.7 million which is a $53.3 million change from an unrealized gain of $35.6 million recorded for Q1/2017. We also recorded an unrealized foreign exchange loss of $36.0 million in Q1/2018 as compared to an unrealized gain of $11.3 million in the same period of 2017. This was offset by a $14.0 million reduction in depletion and depreciation expense along with a $10.5 million increase in the deferred income tax recovery recorded for Q1/2018 relative to Q1/2017.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $72.3 million foreign currency translation gain for the three months ended March 31, 2018 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the weakening of the Canadian dollar against the U.S. dollar. The CAD/USD exchange rate was 1.2901 as at March 31, 2018 compared to 1.2518 as at December 31, 2017.

Capital Expenditures

Capital expenditures for the three months ended March 31, 2018 and 2017 are summarized as follows.

	Three Months Ended March 31					
	2018			2017		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land and seismic	**$ 2,058**	**$ —**	**$ 2,058**	$ 1,617	$ —	$ 1,617
Drilling, completion and equipping	**33,543**	**35,171**	**68,714**	35,278	55,357	90,635
Facilities	**12,991**	**6,838**	**19,829**	1,589	2,718	4,307
Other	**2,933**	**—**	**2,933**	—	—	—
Total exploration and development	**$ 51,525**	**$ 42,009**	**$ 93,534**	$ 38,484	$ 58,075	$ 96,559
Total acquisitions, net of proceeds from divestitures	**(2,026)**	**—**	**(2,026)**	66,004	—	66,004
Total oil and natural gas expenditures	**$ 49,499**	**$ 42,009**	**$ 91,508**	$ 104,488	$ 58,075	$ 162,563
Wells drilled (net)	**29.9**	**6.9**	**36.8**	27.1	8.4	35.5

We invested $93.5 million in exploration and development activities during Q1/2018 which is $3.0 million less than exploration and development expenditures of $96.6 million for Q1/2017. Our Q1/2018 capital program was focused on maintaining the pace of development on our heavy oil properties in Canada and our properties in the Eagle Ford.

Total exploration and development expenditures in Canada were $51.5 million for Q1/2018 compared to $38.5 million in Q1/2017. We drilled 37 (29.9 net) wells and spent $33.5 million on drilling, completion and equipping costs during Q1/2018 compared to drilling 31 (27.1 net) wells during Q1/2017 for $35.3 million. Drilling, completion and equipping costs for Q1/2018 included costs associated with two (4.0 net) stratigraphic exploration wells and four (4.0 net) service wells to support development activity on our Lloydminster properties. Drilling activity at Lloydminster included three (3.0 net) wells and costs for facility construction to support SAGD operations at our Kerrobert thermal project. During the first quarter of 2018, we spent $9.4 million on the construction of a gas plant and strategic infrastructure projects including pipeline expansions to support growth at Peace River.

In the U.S., capital spending of $42.0 million in Q1/2018 decreased from $58.1 million in Q1/2017. We participated in the drilling of 25 (6.9 net) wells and initiated production from 27 (5.5 net) wells during Q1/2018 compared to 36 (8.4 net) wells drilled and 33 (9.4 net) wells on production in the same period of 2017. During Q1/2018, the operator of our Eagle Ford properties was active on our lower working interest lands relative to Q1/2017 which resulted in lower exploration and development expenditures for the first quarter of 2018.

We completed minor acquisition and disposition activity in Q1/2018 for net proceeds of $2.0 million compared to Q1/2017 when our acquisition and disposition activities were primarily comprised of the Peace River acquisition which totaled of $66.1 million.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management involves maintaining a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions and the risk characteristics of our oil and gas properties. At March 31, 2018, our capital structure was comprised of shareholders' capital, long-term debt, working capital and our bank loan.

The capital intensive nature of our operations requires us to maintain adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. We believe that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures. Our adjusted funds flow is dependent on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

Management of debt levels is a priority for Baytex in order to sustain operations and support our plans for long-term growth. At March 31, 2018, net debt was $1,783.4 million, an increase of $49.1 million from $1,734.3 million at December 31, 2017. The weakening of the Canadian dollar relative to the U.S. dollar increased the reported amount of our U.S. dollar denominated debt at March 31, 2018 by $36.0 million.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio. At March 31, 2018, our net debt to adjusted funds flow ratio was 5.3 compared to a ratio of 5.0 as at December 31, 2017. The increase in the net debt to adjusted funds flow ratio relative to December 31, 2017 is attributed to lower adjusted funds flow from lower operating netbacks after derivatives along with an increase in net debt as at March 31, 2018 due to a weakening of the Canadian dollar relative to the U.S. dollar.

Bank Loan

At March 31, 2018, the principal amount of bank loan outstanding was $212.6 million and we had approximately $515 million of available capacity under the credit facility agreement.

On April 25, 2018, Baytex amended its credit facilities to extend maturity from June 4, 2019 to June 4, 2020 and elected to end the covenant relief period early to benefit from reduced borrowing costs. The amended revolving extendible secured credit facilities are comprised of a US$35 million operating loan (previously US$25 million) and a US$340 million syndicated loan (previously $350 million) 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, including the financial covenants detailed below, and do not require any mandatory principal payments prior to maturity on June 4, 2020. 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 exceeds 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.

The agreements relating to the Revolving Facilities are accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts - Credit agreements" on April 13, 2016 and May 2, 2018).

The weighted average interest rate on the credit facilities for Q1/2018 was 4.79% as compared to 3.9% for Q1/2017.

Financial Covenants

On April 25, 2018, we amended the Revolving Facilities and elected to end the covenant relief period early. The following table summarizes the financial covenants applicable the the Revolving Facilities at March 31, 2018 and at April 25, 2018 and our compliance therewith at March 31, 2018.

Covenant Description	Position as at March 31, 2018	March 31, 2018	April 25, 2018 and thereafter
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.50:1.00**	5.00:1.00	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**4.56:1.00**	1.25:1.00	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, 2018, the Company's Senior Secured Debt totaled $227.2 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, unrealized gains and losses on financial derivatives, 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, 2018 was $454.8 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, 2018 were $99.8 million.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.53 billion as at March 31, 2018. 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 2.5:1.0. As at March 31, 2018, the fixed charge coverage ratio was 4.56:1.00.

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. As of July 19, 2017, these notes are redeemable at our option, in whole or in part, 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 "5.125% Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.125% Notes and the 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. As of June 1, 2017, the 5.125% Notes are redeemable at our option, in whole or in part, at specified redemption prices. The 5.625% Notes are redeemable at our option, in whole or in part, commencing on June 1, 2019 at specified redemption prices.

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, 2018, we issued 1.1 million common shares pursuant to our share-based compensation program. As at May 3, 2018, we had 236.6 million common shares issued and outstanding 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 adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of March 31, 2018 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	**$ 155,779**	$ 155,779	$ —	$ —	$ —
Bank loan[(1) (2)]	**212,571**	—	212,571	—	—
Long-term notes[(2)]	**1,525,595**	—	193,515	816,040	516,040
Interest on long-term notes[(3)]	**386,265**	88,412	175,356	88,539	33,958
Operating leases	**26,803**	6,955	12,692	7,156	—
Processing agreements	**39,220**	5,539	9,104	9,004	15,573
Transportation agreements	**31,630**	2,383	17,025	11,350	872
Total	**$ 2,377,863**	$ 259,068	$ 620,263	$ 932,089	$ 566,443

(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, 2020, 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.

QUARTERLY FINANCIAL INFORMATION

	2018	2017				2016		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**286,067**	303,163	258,620	277,536	260,549	233,116	197,648	195,733
Net income (loss)	**(62,722)**	76,038	(9,228)	9,268	11,096	(359,424)	(39,430)	(86,937)
Per common share - basic	**(0.27)**	0.32	(0.04)	0.04	0.05	(1.66)	(0.19)	(0.41)
Per common share - diluted	**(0.27)**	0.32	(0.04)	0.04	0.05	(1.66)	(0.19)	(0.41)
Adjusted funds flow	**84,255**	105,796	77,340	83,136	81,369	77,239	72,106	81,261
Per common share - basic	**0.36**	0.45	0.33	0.35	0.35	0.36	0.34	0.39
Per common share - diluted	**0.36**	0.44	0.33	0.35	0.34	0.36	0.34	0.39
Exploration and development	**93,534**	90,156	61,544	78,007	96,559	68,029	39,579	35,490
Canada	**51,525**	41,864	14,487	18,439	38,484	12,151	6,120	2,747
U.S.	**42,009**	48,292	47,057	59,568	58,075	55,878	33,459	32,743
Acquisitions, net of divestitures	**(2,026)**	(3,937)	(7,436)	5,226	66,004	(322)	(62,752)	(37)
Net debt	**1,783,379**	1,734,284	1,748,805	1,819,387	1,850,909	1,773,541	1,864,022	1,942,538
Total assets	**4,433,074**	4,372,111	4,353,637	4,582,049	4,702,423	4,594,085	4,995,876	5,089,280
Common shares outstanding	**236,578**	235,451	235,451	234,204	234,203	233,449	211,542	210,715
Daily production								
Total production (boe/d)	**69,522**	69,556	69,310	72,812	69,298	65,136	67,167	70,031
Canada (boe/d)	**33,505**	32,194	34,560	34,284	33,217	31,704	33,615	31,722
U.S. (boe/d)	**36,017**	37,362	34,750	38,528	36,081	33,432	33,552	38,309
Benchmark prices								
WTI oil (US$/bbl)	**62.87**	55.40	48.20	48.28	51.91	49.29	44.94	45.60
WCS heavy (US$/bbl)	**38.59**	43.14	38.26	37.16	37.34	34.97	31.44	32.29
CAD/USD avg exchange rate	**1.2651**	1.2717	1.2524	1.3447	1.3229	1.3339	1.3051	1.2885
AECO gas ($/mcf)	**1.85**	1.96	2.04	2.77	2.94	2.81	2.20	1.25
NYMEX gas (US$/mmbtu)	**3.00**	2.93	3.00	3.18	3.32	2.98	2.81	1.95
Sales price ($/boe)	**42.96**	44.75	38.04	39.41	40.16	38.16	31.73	30.52
Royalties ($/boe)	**10.36**	10.86	8.65	9.06	9.17	9.28	7.37	6.65
Operating expense ($/boe)	**10.53**	10.91	10.10	10.70	10.28	9.96	9.07	8.67
Transportation expense ($/boe)	**1.36**	1.20	1.46	1.35	1.29	1.30	1.38	0.81
Operating netback ($/boe)	**20.71**	21.78	17.83	18.30	19.42	17.62	13.91	14.39
Financial derivatives (loss) gain ($/boe)	**(1.57)**	0.30	0.44	0.40	0.04	1.62	3.04	3.74
Operating netback after financial derivatives ($/boe)	**19.14**	22.08	18.27	18.70	19.46	19.24	16.95	18.13

Our operating and financial results have improved as oil prices continue to recover from the multi-year lows experienced in early 2016. Compliance with OPEC's production quotas and increased global demand for crude oil have resulted in the WTI benchmark gradually increasing from US$45.60/bbl in Q2/2016 to US$62.87/bbl in Q1/2018. We increased our capital activity in Canada and the U.S. in Q4/2016 as the outlook for oil prices improved after reducing capital activity in response to the low commodity price environment. Our exploration and development expenditures continue to be focused on our Eagle Ford properties as these assets generate our highest netbacks and rates of return. In Canada, exploration and development activity increased in 2017 after deferring operated heavy oil drilling during the first three quarters of 2016. The increased level of activity has increased production into Q1/2018, after dispositions completed in 2016 and lower capital investment resulted in declining quarterly production through the end of 2016. Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow improved in late 2017 as commodity prices recovered and our daily production increased from 2016. Net debt has decreased from $1,942.5 million at Q2/2016 to $1,783.4 million at Q1/2018 due to non-core asset sales along with the strengthening of the Canadian dollar relative to the U.S. dollar which has decreased the reported amount of our U.S. dollar denominated debt.

2018 GUIDANCE

The following table compares our 2018 annual guidance compared to our Q1/2018 results.

	Guidance (1)	Q1/2018	Variance
Exploration and development capital	$325-$375 million	$93.5 million	N/A
Production (boe/d)	68,000 to 72,000	69,522	— %
Expenses:			
Royalty rate	~ 23%	24.1%	1 %
Operating	$10.50-$11.25/boe	$10.53/boe	— %
Transportation	$1.35-$1.45/boe	$1.36/boe	— %
General and administrative	~ $44 million ($1.72/boe)	$11.0 million ($1.76/boe)	— %
Interest	~ $100 million ($3.95/boe)	$24.5 million ($3.92/boe)	— %

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at March 31, 2018, 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, 2018. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2017.

CHANGES IN ACCOUNTING STANDARDS

Revenue Recognition

Baytex adopted IFRS 15 *Revenue from Contracts with Customers* with a date of initial application of January 1, 2018. For the year ended December 31, 2017, $8.3 million of commodity purchases related to heavy oil sales have been reclassified from petroleum and natural gas sales to blending and other expense to conform with the requirements of IFRS 15. There were no adjustments made to the January 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are provided in note 11 to the consolidated financial statements.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if Baytex acts in the capacity of an agent rather than as a principal.

Revenue from the sale of heavy oil, light oil and condensate, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured.

The transaction price for variable price contracts in the Canada and U.S. segments is based on a representative commodity price index, and may be adjusted for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Financial Instruments

Baytex adopted IFRS 9 *Financial Instruments*, on January 1, 2018 using the retrospective method. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition.

IFRS 9 contains three principal classification categories for initial classification of financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. Financial assets are categorized based on the Company's objective for the asset and the subsequent cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model. Trade and other receivables are classified and measured at amortized cost.

The initial classification of financial liabilities under IFRS 9 is fundamentally unchanged from the requirements under IAS 39. A financial liability is measured at amortized cost or FVTPL. A financial liability is measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL at initial recognition. For liabilities measured at FVTPL, any change in value resulting from a change in Baytex's credit-risk is recorded through other comprehensive income or loss rather than net income or loss. Trade and other payables, bank loan and long-term notes are classified and measured as amortized cost.

Future accounting pronouncements

A description of accounting standards that will be effective in the future is included in the notes to the consolidated financial statements.

NON-GAAP MEASURES

In this MD&A, we refer to certain measures (such as adjusted funds flow, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). While adjusted funds flow, net debt, operating netback and Bank 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 presented by other reporting issuers. We believe that inclusion of these non-GAAP measures provide useful information to investors and shareholders when evaluating the financial results of the Company.

Adjusted Funds Flow

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Adjusted funds flow 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 or loss.

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

	Three Months Ended March 31	
($ thousands)	**2018**	2017
Cash flow from operating activities	**$ 87,612**	$ 80,732
Change in non-cash working capital	**(6,620)**	(4,790)
Asset retirement obligations settled	**3,263**	5,427
Adjusted funds flow	**$ 84,255**	$ 81,369

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, 2018**		December 31, 2017
Bank loan[1]	**$**	**212,571**	$	213,376
Long-term notes[1]		**1,525,595**		1,489,210
Working capital (surplus) deficiency[2]		**45,213**		31,698
Net debt	**$**	**1,783,379**	$	1,734,284

(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 sales, less blending and other 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.

	Three Months Ended March 31			
($ thousands)		**2018**		2017
Petroleum and natural gas sales	**$**	**286,067**	$	260,549
Blending and other expense		**(17,290)**		(10,057)
Total sales, net of blending and other expense		**268,777**		250,492
Less:				
Royalties		**64,839**		57,177
Operating expense		**65,888**		64,130
Transportation expense		**8,519**		8,042
Operating netback		**129,531**		121,143
Realized financial derivative gain (loss)		**(9,841)**		274
Operating netback after realized financial derivatives gain (loss)	**$**	**119,690**	$	121,417

Bank EBITDA

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

	Three Months Ended March 31			
($ thousands)		**2018**		2017
Net income (loss)	**$**	**(62,722)**	$	11,096
Plus:				
Financing and interest		**28,010**		28,506
Unrealized foreign exchange (gain) loss		**36,046**		(11,338)
Unrealized financial derivatives (gain) loss		**17,709**		(35,614)
Current income tax recovery		**(73)**		(736)
Deferred income tax recovery		**(22,917)**		(12,445)
Depletion and depreciation		**108,289**		122,331
Gain on disposition of oil and gas properties		**(1,486)**		—
Non-cash items[1]		**5,934**		5,871
Bank EBITDA	**$**	**108,790**	$	107,671

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

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, 2018.

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; our annual average production rate for 2018; that our investment in a gas plant and strategic infrastructure at Peace River will support future growth; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; that increased crude by rail volumes will mitigate the recent widening of the price differential for WCS; our ability to reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts; 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; that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures; the existence, operation and strategy of our risk management program; our capital budget for 2018; our plans for developing our properties; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2018. 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, 2017, 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

(thousands of Canadian dollars) (unaudited)

As at		March 31, 2018		December 31, 2017
ASSETS				
Current assets				
Trade and other receivables	$	110,566	$	112,844
Financial derivatives (note 17)		16,940		18,510
		127,506		131,354
Non-current assets				
Exploration and evaluation assets (note 5)		271,939		272,974
Oil and gas properties (note 6)		4,024,984		3,958,309
Other plant and equipment		8,645		9,474
	$	4,433,074	$	4,372,111
LIABILITIES				
Current liabilities				
Trade and other payables	$	155,779	$	144,542
Financial derivatives (note 17)		65,579		50,095
Onerous contracts		2,477		2,574
		223,835		197,211
Non-current liabilities				
Bank loan (note 7)		211,831		212,138
Long-term notes (note 8)		1,510,909		1,474,184
Asset retirement obligations (note 9)		371,395		368,995
Deferred income tax liability		186,049		204,698
Financial derivatives (note 17)		655		—
		2,504,674		2,457,226
SHAREHOLDERS' EQUITY				
Shareholders' capital (note 10)		4,451,901		4,443,576
Contributed surplus		11,589		15,999
Accumulated other comprehensive income		535,426		463,104
Deficit		(3,070,516)		(3,007,794)
		1,928,400		1,914,885
	$	4,433,074	$	4,372,111

Subsequent event (note 7)

See accompanying notes to the condensed consolidated interim unaudited financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
(thousands of Canadian dollars, except per common share amounts) (unaudited)

	Three Months Ended March 31	
	2018	2017
Revenue, net of royalties		
Petroleum and natural gas sales (note 11)	**$ 286,067**	$ 260,549
Royalties	**(64,839)**	(57,177)
	221,228	203,372
Expenses		
Operating	**65,888**	64,130
Transportation	**8,519**	8,042
Blending and other	**17,290**	10,057
General and administrative	**11,008**	12,583
Exploration and evaluation (note 5)	**2,019**	1,322
Depletion and depreciation	**108,289**	122,331
Share-based compensation (note 12)	**3,915**	4,549
Financing and interest (note 15)	**28,010**	28,506
Financial derivatives loss (gain) (note 17)	**27,550**	(35,888)
Foreign exchange loss (gain) (note 16)	**36,217**	(10,588)
Gain on disposition of oil and gas properties	**(1,486)**	—
Other (income) expense	**(279)**	413
	306,940	205,457
Net income (loss) before income taxes	**(85,712)**	(2,085)
Income tax recovery		
Current income tax recovery	**(73)**	(736)
Deferred income tax recovery	**(22,917)**	(12,445)
	(22,990)	(13,181)
Net income (loss) attributable to shareholders	**$ (62,722)**	$ 11,096
Other comprehensive income (loss)		
Foreign currency translation adjustment	**72,322**	(18,163)
Comprehensive income (loss)	**$ 9,600**	$ (7,067)
Net income (loss) per common share (note 13)		
Basic	**$ (0.27)**	$ 0.05
Diluted	**$ (0.27)**	$ 0.05
Weighted average common shares (note 13)		
Basic	**236,315**	234,020
Diluted	**236,315**	236,023

See accompanying notes to the condensed consolidated interim unaudited financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Changes in Equity
(thousands of Canadian dollars) (unaudited)

	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
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**
Balance at December 31, 2017	$ 4,443,576	$ 15,999	$ 463,104	$ (3,007,794)	**$ 1,914,885**
Vesting of share awards	8,325	(8,325)	—	—	**—**
Share-based compensation	—	3,915	—	—	**3,915**
Comprehensive income (loss) for the period	—	—	72,322	(62,722)	**9,600**
Balance at March 31, 2018	$ 4,451,901	$ 11,589	$ 535,426	$ (3,070,516)	**$ 1,928,400**

See accompanying notes to the condensed consolidated interim unaudited financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Cash Flows
(thousands of Canadian dollars) (unaudited)

	Three Months Ended March 31	
	2018	2017
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income (loss) for the period	**$ (62,722)**	$ 11,096
Adjustments for:		
Share-based compensation (note 12)	**3,915**	4,549
Unrealized foreign exchange loss (gain) (note 16)	**36,046**	(11,338)
Exploration and evaluation (note 5)	**2,019**	1,322
Depletion and depreciation	**108,289**	122,331
Non-cash financing and accretion (note 15)	**3,499**	3,314
Unrealized financial derivatives loss (gain) (note 17)	**17,709**	(35,614)
Gain on disposition of oil and gas properties	**(1,486)**	—
Deferred income tax recovery	**(22,917)**	(12,445)
Payments on onerous contracts	**(97)**	(1,846)
Asset retirement obligations settled (note 9)	**(3,263)**	(5,427)
Change in non-cash working capital	**6,620**	4,790
	87,612	80,732
Financing activities		
Increase (decrease) in bank loan	**(3,916)**	72,742
	(3,916)	72,742
Investing activities		
Additions to exploration and evaluation assets (note 5)	**(1,287)**	(3,785)
Additions to oil and gas properties (note 6)	**(92,247)**	(92,774)
Additions to other plant and equipment	**—**	(104)
Property acquisitions (note 6)	**(187)**	(66,084)
Proceeds from disposition of oil and gas properties (note 6)	**2,213**	80
Change in non-cash working capital	**7,812**	9,539
	(83,696)	(153,128)
Change in cash	**—**	346
Cash, beginning of period	**—**	2,705
Cash, end of period	**$ —**	$ 3,051
Supplementary information		
Interest paid	**$ 18,876**	$ 19,419
Income taxes paid	**$ 16**	$ 486

See accompanying notes to the condensed consolidated interim unaudited financial statements.

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, 2017 are available through its 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 IFRS and should be read in conjunction with the annual audited consolidated financial statements as at and for the year ended December 31, 2017.

The consolidated financial statements were approved by the Board of Directors of Baytex on May 3, 2018.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2017 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* as described below.

Changes in significant accounting policies

Revenue Recognition

Baytex adopted IFRS 15 *Revenue from Contracts with Customers* with a date of initial application of January 1, 2018. For the year ended December 31, 2017, $8.3 million of commodity purchases related to heavy oil sales have been reclassified from petroleum and natural gas sales to blending and other expense to conform with the requirements of IFRS 15. There were no adjustments made to the January 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are provided in note 11 to these consolidated financial statements.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if Baytex acts in the capacity of an agent rather than as a principal.

Revenue from the sale of heavy oil, light oil and condensate, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured.

The transaction price for variable price contracts in the Canada and U.S. segments is based on a representative commodity price index, and may be adjusted for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Financial Instruments

Baytex adopted IFRS 9 *Financial Instruments*, on January 1, 2018 using the retrospective method. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition.

IFRS 9 contains three principal classification categories for initial classification of financial assets: measured at amortized cost, fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. Financial assets are categorized based on the Company’s objective for the asset and the subsequent cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model. Trade and other receivables are classified and measured at amortized cost.

The initial classification of financial liabilities under IFRS 9 is fundamentally unchanged from the requirements under IAS 39. A financial liability is measured at amortized cost or FVTPL. A financial liability is measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL at initial recognition. For liabilities measured at FVTPL, any change in value resulting from a change in Baytex’s credit-risk is recorded through other comprehensive income or loss rather than net income or loss. Trade and other payables, bank loan and long-term notes are classified and measured as amortized cost.

Measurement Uncertainty and Judgments

Revenue - stand-alone selling price

Management is required to make estimates of the price at which the Company would sell the product separately to customers when allocating the transaction price realized in contracts using relative stand-alone selling prices. When making this estimate, management considers market prices and market conditions, as well as cash flows the Company intends to realize based on risk management policies, based on cost and margin objectives.

Future Accounting Pronouncements

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 or 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. The Company will adopt IFRS 16 on January 1, 2019. The Company has developed a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the consolidated financial statements.

4. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- 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 United States; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended March 31	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 106,814**	$ 108,151	**$ 179,253**	$ 152,398	**$ —**	$ —	**$ 286,067**	$ 260,549
Royalties	**(11,334)**	(12,633)	**(53,505)**	(44,544)	**—**	—	**(64,839)**	(57,177)
	95,480	95,518	**125,748**	107,854	**—**	—	**221,228**	203,372
Expenses								
Operating	**45,420**	43,403	**20,468**	20,727	**—**	—	**65,888**	64,130
Transportation	**8,519**	8,042	**—**	—	**—**	—	**8,519**	8,042
Blending and other	**17,290**	10,057	**—**	—	**—**	—	**17,290**	10,057
General and administrative	**—**	—	**—**	—	**11,008**	12,583	**11,008**	12,583
Exploration and evaluation	**2,019**	1,322	**—**	—	**—**	—	**2,019**	1,322
Depletion and depreciation	**46,340**	49,831	**61,120**	71,353	**829**	1,147	**108,289**	122,331
Share-based compensation	**—**	—	**—**	—	**3,915**	4,549	**3,915**	4,549
Financing and interest	**—**	—	**—**	—	**28,010**	28,506	**28,010**	28,506
Financial derivatives loss (gain)	**—**	—	**—**	—	**27,550**	(35,888)	**27,550**	(35,888)
Foreign exchange loss (gain)	**—**	—	**—**	—	**36,217**	(10,588)	**36,217**	(10,588)
Gain on disposition of oil and gas properties	**(1,486)**	—	**—**	—	**—**	—	**(1,486)**	—
Other (income) expense	**—**	—	**—**	—	**(279)**	413	**(279)**	413
	118,102	112,655	**81,588**	92,080	**107,250**	722	**306,940**	205,457
Net income (loss) before income taxes	**(22,622)**	(17,137)	**44,160**	15,774	**(107,250)**	(722)	**(85,712)**	(2,085)
Income tax recovery								
Current income tax recovery	**—**	—	**(73)**	(736)	**—**	—	**(73)**	(736)
Deferred income tax expense (recovery)	**(6,107)**	(4,628)	**2,239**	(7,520)	**(19,049)**	(297)	**(22,917)**	(12,445)
	(6,107)	(4,628)	**2,166**	(8,256)	**(19,049)**	(297)	**(22,990)**	(13,181)
Net income (loss)	**$ (16,515)**	$ (12,509)	**$ 41,994**	$ 24,030	**$ (88,201)**	$ (425)	**$ (62,722)**	$ 11,096
Total oil and natural gas capital expenditures(1)	**$ 49,499**	$ 104,488	**$ 42,009**	$ 58,075	**$ —**	$ —	**$ 91,508**	$ 162,563

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

As at	**March 31, 2018**	December 31, 2017
Canadian assets	**$ 1,682,178**	$ 1,677,821
U.S. assets	**2,742,251**	2,684,816
Corporate assets	**8,645**	9,474
Total consolidated assets	**$ 4,433,074**	$ 4,372,111

5. EXPLORATION AND EVALUATION ASSETS

		March 31, 2018		December 31, 2017
Balance, beginning of period	**$**	**272,974**	$	308,462
Capital expenditures		**1,287**		7,118
Divestitures		**(872)**		(1,276)
Exploration and evaluation expense		**(2,019)**		(8,253)
Transfer to oil and gas properties		**(4,337)**		(20,198)
Foreign currency translation		**4,906**		(12,879)
Balance, end of period	**$**	**271,939**	$	272,974

6. OIL AND GAS PROPERTIES

		Cost		Accumulated depletion		Net book value
Balance, December 31, 2016	**$**	**7,764,037**	**$**	**(3,611,868)**	**$**	**4,152,169**
Capital expenditures		319,148		—		319,148
Property acquisitions		136,007		—		136,007
Transferred from exploration and evaluation assets		20,198		—		20,198
Transferred from other assets		5,124		—		5,124
Change in asset retirement obligations		42,808		—		42,808
Divestitures		(105,272)		49,291		(55,981)
Foreign currency translation		(249,723)		68,641		(181,082)
Depletion		—		(480,082)		(480,082)
Balance, December 31, 2017	**$**	**7,932,327**	**$**	**(3,974,018)**	**$**	**3,958,309**
Capital expenditures		92,247		—		92,247
Property acquisitions		202		—		202
Transferred from exploration and evaluation assets		4,337		—		4,337
Change in asset retirement obligations		2,598		—		2,598
Divestitures		(62)		—		(62)
Foreign currency translation		107,978		(33,163)		74,815
Depletion		—		(107,462)		(107,462)
Balance, March 31, 2018	**$**	**8,139,627**	**$**	**(4,114,643)**	**$**	**4,024,984**

At the end of each reporting period, the Company performs an assessment to determine whether there is any indication of impairment or reversal of previously recorded impairments for the cash generating units ("CGU") that comprise Oil and Gas Properties. The assessment of indicators is subjective in nature and requires Management to make judgments based on the information available at the reporting date. The Company determined that there were no indicators of impairment or impairment reversals for any of the Company's CGUs as at March 31, 2018.

7. BANK LOAN

		March 31, 2018		December 31, 2017
Bank loan - U.S. dollar denominated(1)	**$**	**112,885**	$	167,159
Bank loan - Canadian dollar denominated		**99,686**		46,217
Bank loan - principal		**212,571**		213,376
Unamortized debt issuance costs		**(740)**		(1,238)
Bank loan	**$**	**211,831**	$	212,138

(1) U.S. dollar denominated bank loan balance as at March 31, 2018 was US$87.5 million (US$133.5 million as at December 31, 2017).

On April 25, 2018, Baytex amended its credit facilities to extend maturity from June 4, 2019 to June 4, 2020. The amended revolving extendible secured credit facilities are comprised of a US$35 million operating loan (previously US$25 million) and a US$340 million syndicated loan for Baytex (previously US$350 million) 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 including the financial covenants detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2020. 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 exceeds 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, 2018, Baytex had $15.0 million of outstanding letters of credit (December 31, 2017 - $14.6 million) under the Revolving Facilities.

At March 31, 2018, 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 in place as at March 31, 2018 and as amended on April 25, 2018.

Covenant Description	**Position as at March 31, 2018**	**March 31, 2018**	**April 25, 2018 and thereafter**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.50:1.00**	5.00:1.00	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**4.56:1.00**	1.25:1.00	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, 2018, the Company's Senior Secured Debt totaled $227.2 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, unrealized gains and losses on financial derivatives, 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, 2018 was $454.8 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, 2018 were $99.8 million.

8. LONG-TERM NOTES

	March 31, 2018	December 31, 2017
6.75% notes (US$150,000 – principal) due February 17, 2021	**193,515**	187,770
5.125% notes (US$400,000 – principal) due June 1, 2021	**516,040**	500,720
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**516,040**	500,720
Total long-term notes - principal	**1,525,595**	1,489,210
Unamortized debt issuance costs	**(14,686)**	(15,026)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,510,909**	$ 1,474,184

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 7) to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at March 31, 2018, the fixed charge coverage ratio was 4.56:1.00.

9. ASSET RETIREMENT OBLIGATIONS

		March 31, 2018		December 31, 2017
Balance, beginning of period	**$**	**368,995**	$	331,517
Liabilities incurred		**1,899**		5,825
Liabilities settled		**(3,263)**		(13,471)
Liabilities acquired		**132**		22,264
Liabilities divested		**(324)**		(19,940)
Accretion (note 15)		**2,308**		8,682
Change in estimate		**699**		(24,028)
Changes in discount rates and inflation rates		**—**		61,011
Foreign currency translation		**949**		(2,865)
Balance, end of period	**$**	**371,395**	$	368,995

10. 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, 2018, 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, 2016	**233,449**	**$**	**4,422,661**
Transfer from contributed surplus on vesting and conversion of share awards	2,002		20,915
Balance, December 31, 2017	**235,451**	**$**	**4,443,576**
Transfer from contributed surplus on vesting and conversion of share awards	1,127		8,325
Balance, March 31, 2018	**236,578**	**$**	**4,451,901**

11. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales primarily consists of revenues earned from the sale of produced oil and natural gas volumes pursuant to fixed or variable price contracts including the physical delivery contracts for fixed volumes outlined in note 17. The activities that generate petroleum and natural gas sales for our Canadian and U.S. operating segments are described below.

Canada Segment

Petroleum and natural gas sales for Baytex's Canada segment primarily consists of revenues generated from the Company's interest in operated oil and natural gas properties and production taken in-kind related to its interest in non-operated oil and natural gas properties. The Company enters contracts with customers for the sale of production volumes with terms ranging from a period of one month to one year.

Under its contracts with customers, Baytex is required to deliver volumes of heavy oil, light oil and condensate, natural gas liquids and natural gas to agreed upon locations where control over the delivered volumes is transferred to the customer. Revenue is recognized when control of each unit of product is transferred to the customer with revenues due on the 25th day of the month following delivery.

Baytex's customers are primarily oil and natural gas marketers and partners in joint operations in the oil and natural gas industry. Concentration of credit risk is mitigated by marketing production to several oil and natural gas marketers under customary industry and payment terms. Baytex reviews the credit worthiness and obtains certain financial assurances from customers prior to entering sales contracts. The financial strength of the Company's customers is reviewed on a routine basis.

U.S. Segment

Petroleum and natural gas sales for Baytex's U.S. segment primarily consists of revenues generated from the Company's interest in non-operated oil and natural gas properties where the Company has not elected its right to take its production in-kind. The operator of the oil and natural gas properties that comprise the U.S. segment enters contracts with customers, conducts the activities required to transfer control of light oil and condensate, natural gas liquids and natural gas volumes to the customer, and collects and remits payments from the customer to Baytex.

The Company's petroleum and natural gas sales from contracts with customers for each reportable segment is set forth in the following table.

	Three Months Ended March 31					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Heavy oil	**$ 91,883**	**$ —**	**$ 91,883**	$ 89,746	$ —	$ 89,746
Light oil and condensate	**4,851**	**144,607**	**149,458**	6,542	116,535	123,077
NGL	**3,356**	**18,178**	**21,534**	2,972	16,724	19,696
Natural gas sales	**6,724**	**16,468**	**23,192**	8,891	19,139	28,030
Total petroleum and natural gas sales	**$ 106,814**	**$ 179,253**	**$ 286,067**	$ 108,151	$ 152,398	$ 260,549

Included in accounts receivable at March 31, 2018 is $88.7 million (December 31, 2017 - $91.6 million) of accrued production revenue related to deliveries for periods ended prior to the reporting date.

12. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $3.9 million for the three months ended March 31, 2018 ($4.5 million for the three months ended March 31, 2017).

The weighted average fair value of share awards granted during the three months ended March 31, 2018 was $4.17 per restricted and performance award and $5.77 per restricted and performance award for the three months ended March 31, 2017.

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, 2016	**1,508**	**1,737**	**3,245**
Granted	1,636	1,584	3,220
Vested and converted to common shares	(959)	(1,043)	(2,002)
Forfeited	(157)	(25)	(182)
Balance, December 31, 2017	**2,028**	**2,253**	**4,281**
Granted	1,941	1,849	3,790
Vested and converted to common shares	(527)	(600)	(1,127)
Forfeited	(113)	(94)	(207)
Balance, March 31, 2018	**3,329**	**3,408**	**6,737**

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

13. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income per share based on the net income or loss 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								
	2018				2017				
		Net loss	**Weighted average common shares (000s)**		**Net loss per share**	Net income	Weighted average common shares (000s)		Net income per share
Net income (loss) - basic	**$**	**(62,722)**	**236,315**	**$**	**(0.27)**	$ 11,096	234,020	$	0.05
Dilutive effect of share awards		**—**	**—**		**—**	—	2,003		—
Net income (loss) - diluted	**$**	**(62,722)**	**236,315**	**$**	**(0.27)**	$ 11,096	236,023	$	0.05

For the three months ended March 31, 2018 and 2017, the effect of 6.7 million share awards and 1.2 million share awards, respectively, were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive.

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31		
		2018	2017
Net loss before income taxes	**$**	**(85,712)**	$ (2,085)
Expected income taxes at the statutory rate of 27.00% (2017 – 26.93%)(1)		**(23,142)**	(563)
Increase (decrease) in income tax recovery resulting from:			
Share-based compensation		**967**	1,228
Non-taxable portion of foreign exchange loss (gain)		**4,912**	(1,334)
Effect of rate adjustments for foreign jurisdictions		**(9,245)**	(11,088)
Effect of change in deferred tax benefit not recognized(2)		**4,912**	(1,334)
Adjustments and assessments		**(1,394)**	(90)
Income tax recovery	**$**	**(22,990)**	$ (13,181)

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Saskatchewan (from 11.75% to 12.00%).
(2) A deferred income tax asset has not been recognized for allowable capital losses of $104 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes ($86 million as at December 31, 2017).

As disclosed in the 2017 annual financial statements, Baytex received several reassessments from the Canada Revenue Agency (the "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 its file. Baytex remains confident that its original tax filings are correct and intends to defend those tax filings through the appeals process.

15. FINANCING AND INTEREST

	Three Months Ended March 31		
		2018	2017
Interest on bank loan	**$**	**2,929**	$ 2,552
Interest on long-term notes		**21,582**	22,640
Non-cash financing		**1,191**	1,130
Accretion on asset retirement obligations (note 9)		**2,308**	2,184
Financing and interest	**$**	**28,010**	$ 28,506

16. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2018	2017
Unrealized foreign exchange loss (gain)	**$ 36,046**	$ (11,338)
Realized foreign exchange loss	**171**	750
Foreign exchange loss (gain)	**$ 36,217**	$ (10,588)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, bank loan and long-term notes.

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. To estimate fair values of its financial instruments, Baytex uses quoted market prices when available, or third-party models and valuation methodologies that use observable market data. Baytex aims to maximize the use of observable inputs, where practical. The fair values of financial instruments, other than financial derivatives, bank loan and long-term notes, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of financial derivatives are based on mark-to-market values of the underlying financial derivative contracts. The fair value of the bank loan is based on the principal amount of borrowings outstanding. The fair value of the long-term notes are based on the trading value of the notes.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	March 31, 2018		December 31, 2017		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL[1]					
Derivatives	**$ 16,940**	**$ 16,940**	$ 18,510	$ 18,510	Level 2
Total	**$ 16,940**	**$ 16,940**	$ 18,510	$ 18,510	
Assets at amortized cost					
Trade and other receivables	**$ 110,566**	**$ 110,566**	$ 112,844	$ 112,844	—
Total	**$ 110,566**	**$ 110,566**	$ 112,844	$ 112,844	
Financial Liabilities					
FVTPL[1]					
Derivatives	**$ (66,234)**	**$ (66,234)**	$ (50,095)	$ (50,095)	Level 2
Total	**$ (66,234)**	**$ (66,234)**	$ (50,095)	$ (50,095)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (155,779)**	**$ (155,779)**	$ (144,542)	$ (144,542)	—
Bank loan	**(211,831)**	**(212,571)**	(212,138)	(213,376)	—
Long-term notes	**(1,510,909)**	**(1,424,996)**	(1,474,184)	(1,430,902)	Level 1
Total	**$ (1,878,519)**	**$ (1,793,346)**	$ (1,830,864)	$ (1,788,820)	

(1) FVTPL means fair value through profit or loss.

There were no transfers between Level 1 and Level 2 in 2017 or during the three months ended March 31, 2018.

Foreign Currency Risk

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

	Assets		Liabilities	
	March 31, 2018	December 31, 2017	**March 31, 2018**	December 31, 2017
U.S. dollar denominated	**US$49,169**	US$51,665	**US$1,138,165**	US$1,294,615

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of May 3, 2018:

	Period	Volume	Price/Unit[1]	Index		Fair Value[2] *($ millions)*
Oil						
Basis swap	Apr 2018 to Jun 2018	2,000 bbl/d	WTI less US$14.23/bbl	WCS	$	1.9
Basis swap	Apr 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS	$	14.5
Basis swap [4]	May 2018 to July 2018	2,000 bbl/d	WTI less US$17.65/bbl	WCS	$	—
Fixed - Sell	Apr 2018 to Dec 2018	14,000 bbl/d	US$52.31/bbl	WTI	$	(54.8)
3-way option [3]	Apr 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI	$	(3.2)
Fixed - Sell	Apr 2018 to Dec 2018	4,000 bbl/d	US$61.31/bbl	Brent	$	(9.1)
Fixed - Sell [4]	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI	$	—
Swaption [5]	Jan 2019 to Dec 2019	2,000 bbl/d	US$59.60/bbl	WTI	$	(3.8)
Swaption [4][5]	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI	$	—
3-way option [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI	$	1.6
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent	$	0.7
Fixed - Sell [4]	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI	$	—
Natural Gas						
Fixed - Sell	Jan 2018 to Dec 2018	15,000 mmbtu/d	US$3.01	NYMEX	$	0.9
Fixed - Sell	Apr 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO	$	1.9
Total					**$**	**(49.4)**
Current asset						16.9
Current liability						65.6
Non-current liability					$	0.7

(1) Based on the weighted average price per unit for the period.
(2) Fair values as at March 31, 2018. For the purposes of the table, contracts entered subsequent to March 31, 2018 will have no fair value assigned.
(3) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$54.40/US$40 contract, Baytex receives WTI plus US$14.40/bbl when WTI is at or below US$40/bbl; Baytex receives US$54.40/bbl when WTI is between US$40/bbl and US$54.40/bbl; Baytex receives the market price when WTI is between US$54.40/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.
(4) Contracts entered subsequent to March 31, 2018.
(5) For these contracts, the counterparty has the right, if exercised on December 31, 2018, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

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

	Three Months Ended March 31			
		2018		2017
Realized financial derivatives loss (gain)	**$**	**9,841**	$	(274)
Unrealized financial derivatives loss (gain)		**17,709**		(35,614)
Financial derivatives loss (gain)	**$**	**27,550**	$	(35,888)

Physical Delivery Contracts

The following physical delivery contracts 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, and as a result no asset or liability has been recognized in the consolidated statements of financial position.

Period	Product	Volume	Price/Unit[1]
Apr 2018 to Dec 2018	WCS	2,000 bbl/d	WTI less US$14.00/bbl

(1) Based on the weighted average price per unit for the period.

As at March 31, 2018, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Period	Volume
Apr 2018 to Dec 2018	5,000 bbl/d
Apr 2018	2,000 bbl/d
May 2018 to Dec 2018	2,000 bbl/d

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.

Mark R. Bly(3)(4)
Independent Businessman

James L. Bowzer(3)
Independent Businessman

Edward Chwyl(2)(3)
Independent Businessman

Trudy M. Curran(1)(2)(4)
Independent Businesswoman

Naveen Dargan(1)(2)
Independent Businessman

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 Human Resources and Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

HEAD OFFICE

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BANKERS

Bank of Nova Scotia
Alberta Treasury Branches
Bank of Montreal
Barclays Bank plc
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Export Development Canada
National Bank of Canada
Royal Bank of Canada
The Toronto-Dominion 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,
Conventional and U.S. Business Units

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

Ryan M. Johnson
Vice President, Peace River Business Unit

Chad L. Kalmakoff
Vice President, Finance

M. Scott Lovett
Vice President, Business Development

Gregory A. Sawchenko
Vice President, Land

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