BAYTEX ENERGY CORP.

Q3 REPORT 2015

SUMMARY

- Generated production(4) of 82,170 boe/d (81% oil and NGL) in Q3/2015;
- Delivered funds from operations ("FFO") of $105.1 million ($0.51 per share) in Q3/2015;
- Realized an operating netback (sales price less royalties, production and operating expenses, and transportation expenses) in Q3/2015 of $15.57/boe ($18.90/boe including financial derivative gains);
- Produced approximately 39,000 boe/d in the Eagle Ford with 14 wells brought onstream during the quarter generating an average 30-day initial production rate of approximately 1,350 boe/d per well;
- Realized drilling cost savings in the Eagle Ford of greater than 10% for the second consecutive quarter (an overall reduction of 27% compared to 2014); and
- Maintained strong levels of financial liquidity with the suspension of our dividend and approximately $1.05 billion in undrawn capacity on our credit facilities.

	Three Months Ended			Nine Months Ended	
	September 30, 2015	June 30, 2015	September 30, 2014	**September 30, 2015**	September 30, 2014
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 268,625**	$ 345,432	$ 634,415	**$ 899,672**	$ 1,496,627
Funds from operations[1]	**105,052**	158,049	297,964	**423,322**	634,277
Per share – basic	**0.51**	0.77	1.79	**2.18**	4.44
Per share – diluted	**0.51**	0.77	1.78	**2.18**	4.40
Cash dividends declared[2]	**17,248**	37,908	89,771	**96,624**	228,610
Dividends declared per share	**0.20**	0.30	0.72	**0.80**	2.06
Net income (loss)	**(517,856)**	(26,955)	144,369	**(720,727)**	229,009
Per share – basic	**(2.49)**	(0.13)	0.87	**(3.71)**	1.60
Per share – diluted	**(2.49)**	(0.13)	0.86	**(3.71)**	1.59
Exploration and development	**126,804**	106,010	230,032	**380,243**	551,373
Acquisitions, net of divestitures	**(498)**	1,170	(341,908)	**2,222**	2,580,819
Total oil and natural gas capital expenditures	**$ 126,306**	$ 107,180	$ (111,876)	**$ 382,465**	$ 3,132,192
Bank loan[3]	**$ 208,195**	$ 192,255	$ 624,067	**$ 208,195**	$ 624,067
Long-term debt[3]	**1,581,002**	1,493,013	1,380,811	**1,581,002**	1,380,811
Working capital deficiency	**160,539**	137,243	250,939	**160,539**	250,939
Total monetary debt[4]	**$ 1,949,736**	$ 1,822,511	$ 2,255,817	**$ 1,949,736**	$ 2,255,817

	Three Months Ended			Nine Months Ended	
	September 30, 2015	June 30, 2015	September 30, 2014	**September 30, 2015**	September 30, 2014
OPERATING					
Daily production					
Heavy oil (bbl/d)	**33,639**	35,397	45,500	**36,067**	45,641
Light oil and condensate (bbl/d)	**24,712**	25,899	28,124	**26,210**	14,569
NGL (bbl/d)	**8,507**	8,232	6,629	**8,322**	3,714
Total oil and NGL (bbl/d)	**66,858**	69,528	80,253	**70,599**	63,924
Natural gas (mcf/d)	**91,869**	91,456	83,300	**91,448**	58,766
Oil equivalent (boe/d @ 6:1)[(5)]	**82,170**	84,770	94,137	**85,840**	73,718
Benchmark prices					
WTI oil (US$/bbl)	**46.43**	57.94	97.17	**51.00**	99.61
WCS heavy oil (US$/bbl)	**33.13**	46.35	76.99	**37.80**	78.50
Edmonton par oil ($/bbl)	**56.22**	67.72	98.65	**58.63**	101.83
LLS oil (US$/bbl)	**49.79**	62.38	101.93	**54.24**	104.55
Baytex average prices (before hedging)					
Heavy oil ($/bbl)[(6)]	**30.90**	44.59	73.99	**34.54**	74.84
Light oil and condensate ($/bbl)	**55.46**	65.11	99.65	**57.54**	100.19
NGL ($/bbl)	**15.35**	15.78	36.77	**16.79**	40.59
Total oil and NGL ($/bbl)	**38.00**	48.82	79.91	**42.39**	78.62
Natural gas ($/mcf)	**3.28**	3.06	4.43	**3.19**	4.73
Oil equivalent ($/boe)	**34.59**	43.34	72.04	**37.10**	71.97
CAD/USD noon rate at period end	**1.3394**	1.2474	1.1208	**1.3394**	1.1208
CAD/USD average rate for period	**1.3094**	1.2294	1.0893	**1.2631**	1.0940
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**19.50**	24.14	49.49	**24.87**	49.88
Low	**3.92**	19.24	41.73	**3.92**	38.90
Close	**4.27**	19.43	42.35	**4.27**	42.35
Volume traded (thousands)	**165,674**	80,572	40,645	**368,426**	140,378
NYSE					
Share price (US$)					
High	**15.51**	20.10	46.46	**20.10**	46.46
Low	**2.92**	15.42	37.54	**2.92**	35.34
Close	**3.20**	15.58	37.86	**3.20**	37.86
Volume traded (thousands)	**109,902**	44,497	5,212	**178,612**	12,915
Common shares outstanding (thousands)	**210,225**	206,193	166,709	**210,225**	166,709

Notes:

(1) *Funds from operations is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define funds from operations as cash flow from operating activities adjusted for finance costs, changes in non-cash operating working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and future dividends. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and nine months ended September 30, 2015.*

(2) *Cash dividends declared are net of participation in our dividend reinvestment plan.*

(3) *Principal amount of instruments.*

(4) *Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives)) and the principal amount of both the long-term debt and the bank loan.*

(5) *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.*

(6) *Heavy oil prices exclude condensate blending.*

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to: our business strategies, plans and objectives; our annual average production rate for 2015; our capital expenditures for 2015; the timing of announcing our 2016 capital and operating budget; our Eagle Ford shale play, including initial production rates from new wells, our plans to use "stack and frac" pilots to target three zones in the Eagle Ford formation in addition to the overlying Austin Chalk formation, our assessment of the results of our "stack and frac" pilots and the number of frac crews completing wells; our expectation that we will return a portion of funds from operations to shareholders under normal operating conditions; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate the volatility in heavy oil price differentials by transporting our crude oil to market on railways; the volume of heavy oil to be transported to market on railways in the fourth quarter of 2015; our liquidity and financial capacity; and our belief that we are well positioned for success as oil prices improve. 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.

Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

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.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash generated from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Total monetary debt is not a measurement based on GAAP in Canada. We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)) and the principal amount of both the long-term debt and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product revenue less royalties, production and operating expenses and transportation expenses dividend by barrels of oil equivalent sales volume for the applicable period. Baytex's determination of operating netback may not be comparable with the calculation of similar measures for other entities. Baytex believes that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

Operations Review

During the third quarter, we continued to position our company to withstand the current low commodity price environment. Drilling activity was reduced in the Eagle Ford and heavy oil drilling in Canada was suspended. We remained focused during the quarter on cost reduction initiatives across all of our operations, including drilling and completions, production and operating expenses and general and administrative expenses. Drilling costs have been reduced by approximately 27% in the Eagle Ford as compared to 2014, and both operating costs and general and administrative expenses have been reduced by approximately 15% versus budget.

Production averaged 82,170 boe/d (81% oil and NGL) in Q3/2015 as compared to 84,770 boe/d in Q2/2015. The reduction in volumes is largely attributable to reduced activity levels in Canada. Capital expenditures for exploration and development activities totaled $126.8 million in Q3/2015 with $93.3 million spent in the U.S. and $33.5 million spent in Canada. During Q3/2015, we participated in the drilling of 57 (29.5 net) wells with a 100% success rate.

With the previously announced reduction in exploration and development activities in Canada, we anticipate our full year capital expenditures will be toward the lower end of our guidance of $500 to $575 million. Similarly, we anticipate our full year 2015 production will be toward the lower end of our guidance of 84,000 to 86,000 boe/d. We are in the process of setting our 2016 capital budget, the details of which are expected to be released in December following approval by our Board of Directors.

Wells Drilled – Three Months Ended September 30, 2015

	Crude Oil		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	17	12.3	–	–	1	1.0	–	–	18	13.3
Peace River	5	5.0	–	–	–	–	–	–	5	5.0
	22	**17.3**	**–**	**–**	**1**	**1.0**	**–**	**–**	**23**	**18.3**
Light oil and natural gas										
Eagle Ford	7	2.2	24	6.7	1	0.3	–	–	32	9.2
Western Canada	–	–	2	2.0	–	–	–	–	2	2.0
	7	**2.2**	**26**	**8.7**	**1**	**0.3**	**–**	**–**	**34**	**11.2**
Total	**29**	**19.5**	**26**	**8.7**	**2**	**1.3**	**–**	**–**	**57**	**29.5**

Wells Drilled – Nine Months Ended September 30, 2015

	Crude Oil		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	26	17.4	–	–	1	1.0	–	–	27	18.4
Peace River	6	6.0	–	–	5	5.0	–	–	11	11.0
	32	**23.4**	**–**	**–**	**6**	**6.0**	**–**	**–**	**38**	**29.4**
Light oil and natural gas										
Eagle Ford	54	12.9	92	24.6	1	0.3	2	0.6	149	38.4
Western Canada	–	–	2	2.0	–	–	–	–	2	2.0
	54	**12.9**	**94**	**26.6**	**1**	**0.3**	**2**	**0.6**	**151**	**40.4**
Total	**86**	**36.3**	**94**	**26.6**	**7**	**6.3**	**2**	**0.6**	**189**	**69.8**

U.S. Operations

Production in the Eagle Ford averaged 38,941 boe/d (78% oil and NGL) during Q3/2015, as compared to 39,548 boe/d in Q2/2015 and 41,076 boe/d in Q1/2015. Capital expenditures in the Eagle Ford in Q3/2015 totaled $93.3 million, down from $98.3 million in Q2/2015 and $126.2 million in Q1/2015. We continue to work with our partner on cost reductions. To-date, we have achieved an approximate 27% reduction in well costs – with wells now being drilled, completed and equipped for approximately US$6.0 million, as compared to US$8.2 million in 2014.

In response to the low crude oil price environment, we have moderated our pace of development throughout 2015. The number of drilling rigs is consistent with our reduced development plan with approximately six rigs currently drilling on our acreage, as compared to 12 rigs in late 2014. As at September 30, 2015, we had 87 (24.2 net) wells waiting on completion. We currently have three frac crews working on completing wells.

In Q3/2015, we participated in the drilling of 32 (9.2 net) wells and commenced production from 31 (6.5 net) wells. Of the 31 wells that commenced production during Q3/2015, 14 wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 1,350 boe/d.

In addition to targeting the Lower Eagle Ford formation, we continue to delineate the Austin Chalk formation with 45 (12.6 net) wells now on production. The wells that came on production in the Austin Chalk during Q3/2015 have established an average 30-day initial production rate of approximately 1,100 boe/d.

Additional advancements have been made to delineate the multi-zone development potential of our Sugarkane acreage. We have initiated "stack and frac" pilots which target up to three zones in the Eagle Ford formation in addition to the overlying Austin Chalk. Recent production data from one pad (a total of six wells) that targeted four zones achieved 30-day initial production rates per well ranging from 700 to 1,480 boe/d. We now have thirteen multi-zone projects in various stages of execution and production.

Canadian Operations

Production in Canada averaged 43,229 boe/d (84% oil and NGL) during Q3/2015, as compared to 45,222 boe/d in Q2/2015. The reduced volumes in Canada are a result of lower drilling activity and uneconomic production that we have shut-in. At September 30, 2015, we had a total of approximately 2,400 boe/d of uneconomic production shut-in, including the Cliffdale Cyclical Steam Stimulation project, which was suspended late in the third quarter. Capital expenditures for our Canadian assets in Q3/2015 totaled $33.5 million, an increase from $7.7 million in Q2/2015.

In the third quarter, we proceeded with our 2015 budget plan in Peace River and Lloydminster, however, as commodity prices deteriorated we suspended our development activities. At Peace River, we drilled five (5.0 net) wells and at Lloydminster, we drilled 17 (12.3 net) wells. We achieved an approximate 20% reduction in well costs – with wells now being drilled, completed, and equipped for approximately $2.7 million at Peace River ($3.4 million previously) and $750,000 at Lloydminster ($950,000 previously).

Financial Review

We generated FFO of $105.1 million ($0.51 per share) in Q3/2015, compared to $158.0 million ($0.77 per share) in Q2/2015. The $52.9 million decline in FFO is largely due to a decline in commodity prices, lower realized hedging gains and lower production volumes. This was partially offset by lower costs associated with our operations, lower transportation and general and administrative expenses along with lower royalties.

We recorded a net loss in Q3/2015 of $517.9 million ($2.49 per share) compared to a net loss of $27.0 million ($0.13 per share) in Q2/2015. The net loss in the quarter is largely attributable to the non-cash impairment charge of $493.2 million ($419.0 million after-tax) related to our Eagle Ford operations. The impairment charge, which is directly attributable to the decline in commodity prices, included $210.3 million related to oil and gas properties and the remaining goodwill of $282.9 million associated with the acquisition. We have determined that no impairments are required on our Canadian operations at this time.

In Q3/2015, our realized sales price decreased as commodity prices decreased. The average price for West Texas Intermediate light oil ("WTI") decreased to US$46.43/bbl during the quarter, as compared to US$57.94/bbl in Q2/2015. This 20% decline in the benchmark index resulted in our realized price for light oil and condensate decreasing only 15% to $55.46/bbl, as our realized price benefited from the weakening Canadian dollar during the period. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, widened to US$13.30/bbl in Q3/2015, as compared to US$11.59/bbl in Q2/2015. The widening differential and lower WTI price resulted in a 29% decrease in the price of WCS. We had a corresponding 31% decrease in our realized heavy oil price to $30.90/bbl over the same period.

We generated an operating netback in Q3/2015 of $15.57/boe ($18.90/boe including financial derivatives gains). Our Canadian operations generated an operating netback of $10.68/boe while the Eagle Ford generated an operating netback of $21.01/boe. Our Eagle Ford assets are located in south Texas and are proximal to Gulf Coast crude oil markets with established transportation systems, resulting in stronger realized prices. Our light oil and condensate production in the Eagle Ford is priced primarily off a Louisiana Light Sweet crude oil benchmark which typically trades at a premium to WTI. This strong pricing, combined with low cash costs, contributed positively to our operating netback in Q3/2015.

During the quarter, we continued to focus on cost reduction initiatives across all of our operations. Production and operating expenses decreased 10% on a per boe basis as compared to Q3/2014, despite the impact of fixed costs on lower production in Canada. We are also benefiting from the Eagle Ford assets which have lower costs and comprise a larger percentage of our production. Transportation expenses in Canada have been reduced by 27% on a per boe basis as compared to Q3/2014, due to overall cost reduction initiatives, which includes the use of internal trucking and decreased fuel charges.

The table below provides a summary of our operating netbacks for the periods noted.

	Three Months Ended Sept. 30, 2015			Three Months Ended Sept. 30, 2014	
($ per boe)	Canada	Eagle Ford	Total	Total	Change
Sales Price	$ 29.06	$ 40.72	$ 34.59	$ 72.04	(52%)
Other income	0.69	–	0.36	–	100%
Less:					
Royalties	3.88	11.74	7.61	17.43	(56%)
Production and operating expenses	12.31	7.97(1)	10.25	11.39	(10%)
Transportation expenses	2.88	–	1.52	2.36	(36%)
Operating netback	$ 10.68	$ 21.01	$ 15.57	$ 40.86	(61%)
Financial derivatives gain (loss)	–	–	3.33	(0.47)	–%
Operating netback after financial derivatives	$ 10.68	$ 21.01	$ 18.90	$ 40.39	(52%)

(1) In the Eagle Ford, transportation expenses are included in production and operating expenses.

General and administrative expenses were $14.0 million in Q3/2015 as compared to $16.8 million in Q3/2014. The decrease is primarily a result of reductions to staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending.

As previously announced on August 20, 2015, we suspended our monthly cash dividend following the September 15, 2015 payment. We believe this was a prudent step to minimize additional bank borrowings during this period of extremely low commodity prices. We continue to believe in returning a portion of our funds from operations to shareholders under normal operating conditions. However, based on the current forward strip, we would not generate sufficient free cash flow to pay a dividend.

Risk Management

We employ a comprehensive risk management program which is intended to reduce some of the volatility in our FFO. In Q3/2015, we realized financial derivatives gains of $25.2 million, primarily due to crude oil prices being at levels significantly below those set in our fixed price contracts, which were partially offset by the settlement of our out-of-money foreign exchange contracts.

As part of our hedging program, we also focus on opportunities to mitigate the volatility in WCS price differentials by transporting crude oil to markets by rail when economics warrant. We have no fixed investment or take or pay obligations to transport crude oil by rail and infrastructure around our core heavy oil producing regions allows for optimization between rail and pipe. In Q3/2015, approximately 16,000 bbl/d of our heavy oil volumes were delivered to market by rail, down 20% from the previous quarter as we optimize our heavy oil netbacks. For Q4/2015, we expect to deliver approximately 15,000 bbl/d of our heavy oil volumes to market by rail.

For Q4/2015, we have entered into hedges on approximately 22% of our net WTI exposure with 20% fixed at US$76.37/bbl and 2% hedged utilizing a 3-way collar structure (as described in the table below). For 2016, Baytex has entered into hedges on approximately 38% of its net WTI exposure with 15% fixed at US$63.64/bbl and 23% hedged utilizing a 3-way collar structure.

The unrealized financial derivatives gain with respect to our WTI hedges as at September 30, 2015 was $81.9 million. The following table summarizes our WTI hedges in place as at November 5, 2015.

	Q4/2015	Full-Year 2016	Full-Year 2017
Fixed Hedges			
Volumes (bbl/d)	9,667	6,250	–
Hedge (%)(1)	20%	15%	–
Price (US$/bbl)	$76.37	$63.64	–
3-Way Option			
Volumes (bbl/d)	1,000	9,500	2,000
Hedge (%)(1)	2%	23%	5%
Average Ceiling/Floor/Sold Floor (US$/bbl)(2)	$62.50/$50/$40	$60/$50/$40	$60/$50/$40
Total Hedge Volume			
Volumes (bbl/d)	10,667	15,750	2,000
Hedge (%)(1)	22%	38%	5%

(1) Percentage of hedged volumes is based on the mid-point of our 2015 production guidance (excluding NGL), net of royalties.

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

Financial Liquidity

We have taken several steps to maintain strong levels of financial liquidity this year, including evaluating our level and timing of capital spending, negotiating cost savings with service providers, reducing staffing levels, completing an equity financing and suspending the monthly dividend.

Total monetary debt at September 30, 2015 was $1.95 billion, comprised of a bank loan of $208 million, long-term debt of $1.58 billion and a working capital deficiency of $161 million. The increase in total monetary debt at September 30, 2015, as compared to June 30, 2015, was primarily due to the Canadian dollar increase of our U.S. dollar denominated debt as well as capital expenditures and cash dividends exceeding FFO for the quarter.

We have unsecured revolving credit facilities consisting of a $1.0 billion Canadian facility and a US$200 million U.S. facility. As at September 30, 2015, we had approximately $1.05 billion in undrawn capacity on these facilities, which do not mature until June 2019.

Conclusion

During the third quarter, we continued to position our company to withstand the current low commodity price environment. Consistent with our revised plans for 2015, we moved forward with a slower pace of development in the Eagle Ford and suspended heavy oil drilling in Canada. We remained focused on cost reduction initiatives across all of our operations and maintaining strong levels of financial liquidity. We have built an exceptional asset base focused on crude oil and liquids with a significant inventory of development prospects. We are well positioned for success as oil prices improve

We want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
November 6, 2015

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 and nine months ended September 30, 2015. This information is provided as of November 5, 2015. 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 third quarter results have been compared with the corresponding period in 2014. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three and nine months ended September 30, 2015, its audited comparative consolidated financial statements for the years ended December 31, 2014 and 2013, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2014. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

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

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and asset retirement obligations settled. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income. For a reconciliation of funds from operations to cash flow from operating activities, see "Funds from Operations, Payout Ratio and Dividends".

Payout Ratio

We define payout ratio as cash dividends (net of participation in the dividend reinvestment plan ("DRIP")) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt

We define total monetary debt as the sum of the principal amount of both the long-term debt and the bank loan and working capital surplus or deficit (which is current assets less current liabilities (excluding current financial derivatives)). We believe that this measure assists in providing a more complete understanding of our cash liabilities. See "Liquidity, Capital Resources and Risk Management" for a calculation of total monetary debt.

Operating Netback

We define operating netback as revenues, net of royalties, less production and operating expenses and transportation expenses divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

THIRD QUARTER HIGHLIGHTS

Production for the three months ended September 30, 2015 averaged 82,170 boe/d, a 13% decrease compared to the same period in 2014 due to production declines in Canada as a result of reduced capital spending along with the asset dispositions in 2014. Canadian production was 43,229 boe/d for the third quarter of 2015, representing a decline of 4% from the second quarter of 2015 and a decline of 24% or 13,524 boe/d compared to the third quarter of 2014. For the nine months ended September 30, 2015, production averaged 85,840 boe/d with Canadian production of 45,993 boe/d, down 19% compared to the same period in 2014. Reduced capital spending, property dispositions and shut-in production have contributed to reduced production levels in Canada in 2015. U.S. production of 38,941 boe/d in the third quarter of 2015 was 4% higher than in the third quarter of 2014 with production from the Eagle Ford increasing 15%. This was offset by the North Dakota disposition which closed on September 24, 2014. We anticipate our full year 2015 production will be near the lower end of our guidance of 84,000 to 86,000 boe/d.

The third quarter of 2015 was marked by low commodity prices as West Texas Intermediate oil ("WTI") dipped to a six-year low. The price of WTI averaged US$46.43/bbl during the third quarter of 2015, a 52% decrease from the same period in 2014. Our hedging contracts and a weaker Canadian dollar mitigated some of the drop in commodity prices. The nine months ended September 30, 2015 was also negatively impacted by declines in commodity pricing resulting in a lower realized price of $37.10/boe or a decrease of 49% as compared to the same period of 2014. In light of the low commodity prices and in order to maintain financial flexibility we made the difficult decision to suspend our monthly dividend in September and further reduced our heavy oil capital program in Canada.

We reduced capital spending in the third quarter of 2015 to $126.8 million, down $103.2 million from the $230.0 million spent in the third quarter of 2014. This reduction is directly attributable to the drop in commodity prices. We invested $33.5 million in Canada during the third quarter which is down $43.1 million from the same period in 2014. Despite negotiated cost reductions from service providers, the current commodity prices do not support further drilling resulting in a deferral of the heavy oil capital program in Canada. In the third quarter of 2015, $93.3 million, or 74% of our capital spending was directed to the Eagle Ford assets. The third quarter capital investment program in the Eagle Ford was down from $98.3 million in the second quarter of 2015 and $140.3 million in the third quarter of 2014. We anticipate our full year 2015 capital expenditures will be toward the lower end of our guidance of $500 to $575 million.

Funds from operations ("FFO") for the three and nine months ended September 30, 2015 were $105.1 million and $423.3 million, respectively, compared to $298.0 million and $634.3 million, for the same periods of 2014. The decrease in FFO is due to both lower commodity prices and lower production volumes.

During the quarter, we recorded an impairment charge of $493.2 million on our Eagle Ford operations. The impairment charge is directly attributable to the decline in commodity prices as the acquired assets were recorded at their fair values when the WTI price was more than US$100/bbl.

RESULTS OF OPERATIONS

The Canadian division includes the heavy oil assets in Peace River and Lloydminster and the conventional oil and natural gas assets in Western Canada. The U.S. division includes the Bakken assets in North Dakota up to the date of disposition on September 24, 2014 and the Eagle Ford assets in Texas subsequent to the date of acquisition on June 11, 2014.

Production

	Three Months Ended September 30					
	2015			2014		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	33,639	–	33,639	45,500	–	45,500
Light oil and condensate	1,729	22,983	24,712	2,628	25,496	28,124
NGL	985	7,522	8,507	1,174	5,455	6,629
Total liquids (bbl/d)	36,353	30,505	66,858	49,302	30,951	80,253
Natural gas (mcf/d)	41,256	50,613	91,869	44,703	38,597	83,300
Total production (boe/d)	43,229	38,941	82,170	56,753	37,384	94,137
Production Mix						
Heavy oil	77%	–%	40%	80%	–%	48%
Light oil and condensate	4%	59%	30%	5%	68%	30%
NGL	3%	19%	11%	2%	15%	7%
Natural gas	16%	22%	19%	13%	17%	15%

	Nine Months Ended September 30					
	2015			2014		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	36,067	–	36,067	45,641	–	45,641
Light oil and condensate	1,905	24,305	26,210	2,664	11,905	14,569
NGL	1,102	7,220	8,322	1,461	2,253	3,714
Total liquids (bbl/d)	39,074	31,525	70,599	49,766	14,158	63,924
Natural gas (mcf/d)	41,514	49,934	91,448	43,033	15,733	58,766
Total production (boe/d)	45,993	39,847	85,840	56,938	16,780	73,718
Production Mix						
Heavy oil	79%	–%	41%	79%	–%	61%
Light oil and condensate	4%	62%	31%	5%	71%	21%
NGL	2%	18%	10%	3%	13%	5%
Natural gas	15%	20%	18%	13%	16%	13%

Total production for the three months ended September 30, 2015 averaged 82,170 boe/d, a decrease of 13% compared to the same period in 2014. Production in Canada decreased 24% compared to prior period, to 43,229 boe/d, with declines from reduced capital spending and approximately 3,000 boe/d from non-core dispositions and uneconomic production we have shut-in. At September 30, 2015, we had approximately 2,400 boe/d of uneconomic production shut-in. U.S. production for the three months ended September 30, 2015 increased 4% to 38,941 boe/d, as production in the Eagle Ford increased 15% due to our ongoing development program. This was partially offset by the disposition of the North Dakota assets on September 24, 2014.

Production for the nine months ended September 30, 2015 averaged 85,840 boe/d, an increase of 16% compared to the same period in 2014. The overall increase is due to the acquisition of the Eagle Ford assets in June of 2014 which outweighed the non-core dispositions and production declines in Canada. Canadian production for the nine months ended September 30, 2015 decreased 19%, to 45,993 boe/d compared to 56,938 boe/d in 2014. This reduction is due to reduced capital spending over the prior period combined with non-core dispositions in late 2014 and uneconomic production we have shut-in which lowered average production by approximately 2,500 boe/d. U.S. production for the nine months ended September 30, 2015 was 39,847 boe/d, an increase of 137% over the prior period as the Eagle Ford production is included for the full nine months during 2015 and was only included from June 11, 2014 for 2014. This was offset by the divestiture of the North Dakota production which produced 3,326 boe/d for the nine months ended September 30, 2014.

Commodity Prices

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

Crude Oil

For the three months ended September 30, 2015, the price of WTI averaged US$46.43/bbl, a 52% decrease from the average WTI price of US$97.17/bbl in the third quarter of 2014 and a 20% decrease from US$57.94/bbl in the second quarter of 2015. For the nine months ended September 30, 2015, the price of WTI averaged US$51.00/bbl, a 49% decrease from the average WTI price of US$99.61/bbl for the same period in 2014. The low prices experienced during the three and nine months ended September 30, 2015, as compared to the same periods in 2014, was brought on by the ongoing global over supply of oil stemming from high North American production growth and the decision by the Organization of Petroleum Exporting Countries (OPEC) to step away from its role as the swing producer.

The discount for Canadian heavy oil is measured by the WCS price differential between WTI and Western Canadian Select ("WCS") heavy oil. For the three and nine months ended September 30, 2015, the WCS heavy oil differential averaged US$13.30/bbl and US$13.20/bbl, respectively, down from US$20.18/bbl and US$21.11/bbl, for the same periods of 2014. The WCS differential narrowed in the three and nine months ended September 30, 2015 as compared to the same periods in 2014 due to stronger refinery demand for WCS and improved market access. This can be partially attributable to ongoing improvements in rail infrastructure over the past two years and the addition of the Flanagan South pipeline which added approximately 600,000 boe/d of market access in November of 2014.

Natural Gas

For the three and nine months ended September 30, 2015, the AECO natural gas price averaged $2.70/mcf and $2.77/mcf, respectively, as compared to $4.22/mcf and $4.55/mcf for the comparative periods of 2014. For the three and nine months ended September 30, 2015, the NYMEX natural gas prices averaged US$2.77/mmbtu and US$2.80/mmbtu, respectively, as compared to US$4.05/mmbtu and US$4.55/mmbtu the same periods of 2014. The decrease in natural gas prices on both indices during 2015 was driven by historically high production levels.

The following tables compare selected benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	$ 46.43	$ 97.17	(52%)	$ 51.00	$ 99.61	(49%)
WCS heavy oil (US$/bbl)[2]	$ 33.13	$ 76.99	(57%)	$ 37.80	$ 78.50	(52%)
Heavy oil differential[3]	29%	21%		27%	21%	
LLS oil (US$/bbl)[4]	$ 49.79	$ 101.93	(51%)	$ 54.24	$ 104.55	(48%)
CAD/USD average exchange rate	1.3094	1.0893	20%	1.2631	1.0940	15%
Edmonton par oil ($/bbl)	$ 56.22	$ 98.65	(43%)	$ 58.63	$ 101.83	(42%)
AECO natural gas price ($/mcf)[5]	$ 2.70	$ 4.22	(36%)	$ 2.77	$ 4.55	(39%)
NYMEX natural gas price (US$/mmbtu)[6]	$ 2.77	$ 4.05	(32%)	$ 2.80	$ 4.55	(38%)

(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) Heavy oil differential refers to the WCS discount to WTI on a monthly weighted average basis.

(4) LLS refers to the Argus trade month average.

(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").

(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended September 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	$ 30.90	$ –	$ 30.90	$ 73.99	$ –	$ 73.99
Light oil and condensate ($/bbl)	51.86	55.73	55.46	92.92	100.35	99.65
NGL ($/bbl)	15.05	15.39	15.35	48.83	34.18	36.77
Natural gas ($/mcf)	2.72	3.74	3.28	4.19	4.71	4.43
Weighted average ($/boe)[2]	$ 29.06	$ 40.72	$ 34.59	$ 67.93	$ 78.28	$ 72.04

	Nine Months Ended September 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	$ 34.54	$ –	$ 34.54	$ 74.84	$ –	$ 74.84
Light oil and condensate ($/bbl)	53.84	57.83	57.54	95.91	101.15	100.19
NGL ($/bbl)	21.06	16.14	16.79	49.36	34.89	40.59
Natural gas ($/mcf)	2.67	3.62	3.19	4.69	4.85	4.73
Weighted average ($/boe)[2]	$ 32.23	$ 42.73	$ 37.10	$ 69.29	$ 80.99	$ 71.97

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on production volumes, net of blending costs.

Average Realized Sales Prices

Our realized heavy oil price for the three months ended September 30, 2015 was $30.90/bbl, or 71% of WCS expressed in Canadian dollars, compared to $73.99/bbl, or 88% of WCS expressed in Canadian dollars in 2014. Our realized heavy oil price for the nine months ended September 30, 2015 was $34.54/bbl, or 72% of WCS expressed in Canadian dollars, compared to $74.84/bbl, or 86% of WCS expressed in Canadian dollars in 2014. The Company's decrease in realized heavy oil price of 58% for the three months ended September 30, 2015 and 54% for the nine months ended September 30, 2015 compared to the same periods in 2014 corresponds with the overall decline in global crude oil prices. A portion of the Company's heavy oil is sold at a fixed dollar differential to the WCS benchmark price. Due to the drop in commodity prices, the fixed dollar differential has decreased our realized price as a percentage of WCS.

During the three months ended September 30, 2015, our Canadian average sales price for light oil and condensate was $51.86/bbl, down 44% from $92.92/bbl in 2014. This corresponds with the 43% decrease in the benchmark Edmonton Par prices over the same period. U.S. light oil and condensate pricing for the three months ended September 30, 2015 was $55.73/bbl, down 44% from $100.35/bbl in the third quarter of 2014, largely in line with the 40% decrease in the LLS benchmark (as expressed in Canadian dollars) over the same period. During the nine months ended September 30, 2015, our Canadian average sales price for light oil and condensate was $53.84/bbl, down 44% from $95.91/bbl in 2014, largely in line with the 42% decrease in Edmonton Par price over the same period. U.S. light oil and condensate pricing for the nine months ended September 30, 2015 was $57.83/bbl, down 43% from $101.15/bbl in the first nine months of 2014, in line with the 42% decrease in the LLS benchmark (as expressed in Canadian dollars) over the same period.

Our realized natural gas price for the three and nine months ended September 30, 2015 was $3.28/mcf and $3.19/mcf, respectively, down from $4.43/mcf and $4.73/mcf over the same periods in 2014. This is largely in line with the decreases in the AECO and NYMEX benchmarks during these periods.

Gross Revenues

	Three Months Ended September 30					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 95,634	$ –	$ 95,634	$ 309,719	$ –	$ 309,719
Light oil and condensate	8,252	117,840	126,092	22,466	235,377	257,843
NGL	1,365	10,647	12,012	5,272	17,150	22,422
Total oil revenue	105,251	128,487	233,738	337,457	252,527	589,984
Natural gas revenue	10,308	17,405	27,713	17,249	16,709	33,958
Total oil and natural gas revenue	115,559	145,892	261,451	354,706	269,236	623,942
Other income	2,746	3	2,749	–	(2)	(2)
Heavy oil blending revenue	4,425	–	4,425	10,475	–	10,475
Total petroleum and natural gas revenues	$ 122,730	$ 145,895	$ 268,625	$ 365,181	$ 269,234	$ 634,415

	Nine Months Ended September 30					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 340,116	$ –	$ 340,116	$ 932,448	$ –	$ 932,448
Light oil and condensate	28,004	383,683	411,687	69,747	328,762	398,509
NGL	6,337	31,814	38,151	19,690	21,461	41,151
Total oil revenue	374,457	415,497	789,954	1,021,885	350,223	1,372,108
Natural gas revenue	30,230	49,317	79,547	55,104	20,812	75,916
Total oil and natural gas revenue	404,687	464,814	869,501	1,076,989	371,035	1,448,024
Other income	7,572	38	7,610	–	413	413
Heavy oil blending revenue	22,561	–	22,561	48,190	–	48,190
Total petroleum and natural gas revenues	$ 434,820	$ 464,852	$ 899,672	$1,125,179	$ 371,448	$1,496,627

Total petroleum and natural gas revenues for the three months ended September 30, 2015 of $268.6 million decreased $365.8 million from the third quarter of 2014. The majority of the decrease from the prior period can be attributed to the drop in commodity prices which accounted for $283 million of the decrease and lower production volumes which accounted for $79 million of the decrease. In Canada, petroleum and natural gas revenues for the three months ended September 30, 2015 totaled $122.7 million, a decrease of $242.5 million compared to the same period in 2014. This is due to a 57% decrease in realized prices on all products combined with a 24% reduction in production volumes compared to the prior year. Petroleum and natural gas revenues of $145.9 million in the U.S. decreased $123.3 million from prior year. This reduction can be attributed to a 48% decrease in realized price and the divestiture of the North Dakota assets which were partially offset by a 15% increase in Eagle Ford production over the period.

Total petroleum and natural gas revenues for the nine months ended September 30, 2015 of $899.7 million decreased $597.0 million from the nine months ended September 30, 2014. The majority of the decrease from the prior period can be attributed to the drop in commodity prices which accounted for $817 million of the decrease, partially offset by higher production volumes contributing $238 million. In Canada, petroleum and natural gas revenues for the nine months totaled $434.8 million, a decrease of $690.4 million compared to the same period in 2014. This is due to a 53% decrease in realized prices on all products combined with a 19% reduction in production volumes. Petroleum and natural gas revenues of $464.9 million in the U.S. increased $93.4 million from the prior year due to the acquisition of the Eagle Ford assets offset by the decrease in revenue due to the sale of North Dakota.

Heavy oil blending revenue of $4.4 million and $22.6 million for the three and nine months ended September 30, 2015, respectively, decreased $6.0 million and $25.6 million, compared to the same periods in 2014. The Company used and sold less diluent during 2015 due to the decrease in heavy oil production within Canada and the increase in transportation by rail which does not require diluent. In addition, the price of blending diluent has declined consistent with the decrease in the price of oil.

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 tables summarize our royalties and royalty rates for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30					
	2015			2014		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 15,445	$ 42,058	$ 57,503	$ 70,231	$ 80,691	$ 150,922
Average royalty rate(1)	13.4%	28.8%	22.0%	19.8%	30.0%	24.2%
Royalty rate per boe	$ 3.88	$ 11.74	$ 7.61	$ 13.45	$ 23.46	$ 17.43

	Nine Months Ended September 30					
	2015			2014		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 57,122	$ 134,974	$ 192,096	$ 225,458	$ 112,625	$ 338,083
Average royalty rate(1)	14.1%	29.0%	22.1%	20.9%	30.4%	23.3%
Royalty rate per boe	$ 4.55	$ 12.41	$ 8.20	$ 14.50	$ 24.59	$ 16.80

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

Total royalties for the three months ended September 30, 2015 of $57.5 million decreased 62%, or $93.4 million from 2014, due to the declines in revenue and production. Canadian royalties decreased to 13.4% of revenue for the three months ended September 30, 2015, from 19.8% of revenue in 2014. Canadian crown royalty rates are partially based on price. The lower commodity prices experienced during 2015 have resulted in lower crown royalty rates compared to 2014. U.S. royalties for the three months ended September 30, 2015 of $42.1 million decreased 48%, or $38.6 million due to lower commodity prices when compared to the same period in 2014. The Eagle Ford royalty rate of 28.8% was comparable to the same period in 2014 as royalty rates for our Eagle Ford assets do not vary with commodity pricing.

Total royalties for the nine months ended September 30, 2015 of $192.1 million decreased 43%, or $146.0 million from 2014, mainly due to the decline in revenues. Canadian royalties have decreased to 14.1% of revenue for the nine months ended September 30, 2015, compared to 20.9% of revenue in 2014. Canadian crown royalty rates are partially based on price. The lower commodity prices experienced during 2015 have resulted in lower crown royalty rates compared to 2014. U.S. royalties for the nine months ended September 30, 2015 of $134.9 million increased 20%, or $22.3 million due to the inclusion of Eagle Ford for the nine months in 2015. The 2014 period only includes the results of the Eagle Ford assets subsequent to the acquisition on June 11, 2014. Royalty rates for 2015 have decreased to 29.0% compared to 30.4% in the prior period due to the disposition of the North Dakota assets that had a higher royalty rate than the Eagle Ford assets.

Production and Operating Expenses

	Three Months Ended September 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Production and operating expenses	$ 48,946	$ 28,544	$ 77,490	$ 66,311	$ 32,314	$ 98,625
Production and operating expenses per boe	$ 12.31	$ 7.97	$ 10.25	$ 12.70	$ 9.39	$ 11.39

	Nine Months Ended September 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Production and operating expenses	$ 164,860	$ 82,465	$ 247,325	$ 198,867	$ 45,088	$ 243,955
Production and operating expenses per boe	$ 13.13	$ 7.58	$ 10.55	$ 12.79	$ 9.84	$ 12.12

(1) Production and operating expenses related to the Eagle Ford assets include transportation expenses.

Production and operating expenses were $77.5 million and $247.3 million for the three and nine months ended September 30, 2015, respectively, representing a decrease of $21.1 million and an increase of $3.4 million compared to the same periods in 2014. On a per boe basis, production and operating expenses for the three and nine months ended September 30, 2015 decreased to $10.25/boe and $10.55/boe, respectively, compared to $11.39/boe and $12.12/boe for the same periods in 2014. Production and operating per boe costs have decreased from the prior period due to cost saving initiatives across all our operations combined with the addition of the Eagle Ford assets which have lower costs and comprise a larger percentage of our total production in 2015 as compared to 2014.

Canadian production and operating expenses of $48.9 million and $164.9 million for the three and nine months ended September 30, 2015 decreased $17.4 million and $34.0 million compared to the same periods in 2014. These decreases are a result of lower production volumes and realized cost savings on our operations. Canadian production and operating expenses per boe decreased $0.39/boe for the three months ended September 30, 2015 compared to the same period in 2014, which reflects the realization of cost saving initiatives. Operating expenses per boe for the nine months ended September 30, 2015 have increased $0.34/boe compared to the same period in 2014 due to the impact of fixed costs on lower production (as production volumes decrease the cost on a per boe basis increases). However, we are working to mitigate the fixed cost impact through cost saving initiatives.

U.S. production and operating expenses of $28.5 million and $82.5 million for the three and nine months ended September 30, 2015, respectively, decreased $3.8 million and increased $37.4 million compared to the same periods in 2014. U.S. production and operating expenses per boe decreased $1.42/boe and $2.26/boe, for the three and nine months ended September 30, 2015, respectively, which reflects the shift in production to the lower cost Eagle Ford assets compared to our historic North Dakota properties and cost saving initiatives.

Transportation and Blending Expenses

Transportation expenses include the costs to move production from the field to the sales point. The largest component of transportation expense relates to the movement of heavy oil to pipeline and rail terminals. In order to meet pipeline specifications and to facilitate its marketing, heavy oil transported through pipelines requires blending to reduce its viscosity. The cost of blending diluent is recovered in the sale price of the blended product. Our heavy oil transported by rail does not require blending diluent.

The following tables compare our transportation and blending expenses for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.(2)	Total	Canada	U.S.(2)	Total
Blending expenses	$ 4,424	$ –	$ 4,424	$ 10,475	$ –	$ 10,475
Transportation expenses	11,456	–	11,456	20,456	–	20,456
Total transportation and blending expenses	$ 15,880	$ –	$ 15,880	$ 30,931	$ –	$ 30,931
Transportation expenses per boe(1)	$ 2.88	$ –	$ 1.52	$ 3.92	$ –	$ 2.36

	Nine Months Ended September 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.(2)	Total	Canada	U.S.(2)	Total
Blending expenses	$ 22,561	$ –	$ 22,561	$ 48,191	$ –	$ 48,191
Transportation expenses	42,331	–	42,331	66,228	–	66,228
Total transportation and blending expenses	$ 64,892	$ –	$ 64,892	$ 114,419	$ –	$ 114,419
Transportation expenses per boe(1)	$ 3.37	$ –	$ 1.81	$ 4.26	$ –	$ 3.29

(1) Transportation expenses per boe exclude the purchase of blending diluent.

(2) Transportation expenses related to the Eagle Ford assets are included in production and operating expenses.

Transportation expenses for the three months ended September 30, 2015 totaled $11.5 million, a decrease of 44%, or $9.0 million, compared to 2014. Transportation expenses for the nine months ended September 30, 2015 totaled $42.3 million, a decrease of 36%, or $23.9 million, compared to 2014. The decreases for both comparative periods are due to lower heavy oil volumes, decreased fuel surcharges and overall cost saving initiatives which includes the increased use of internal trucking.

Blending expenses for the three and nine months ended September 30, 2015 of $4.4 million and $22.6 million, respectively, have decreased $6.1 million and $25.6 million, compared to the same periods in 2014. Consistent with the decrease in heavy oil blending revenue, blending expenses decreased due to a decrease in both the price of blending diluent and the volume of blending diluent required.

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 funds from operations. Financial derivatives are managed at the corporate level and are not allocated between divisions. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price. Changes in the fair value of contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	2015	2014	Change	2015	2014	Change
Realized financial derivatives gain (loss)						
Crude oil	$ 36,628	$ (2,811)	$ 39,439	$ 193,439	$ (13,252)	$ 206,691
Natural gas	577	45	532	6,614	(1,771)	8,385
Foreign currency	(12,053)	(1,281)	(10,772)	(32,995)	(4,547)	(28,448)
Interest	–	(4,109)	4,109	–	(8,130)	8,130
Total	$ 25,152	$ (8,156)	$ 33,308	$ 167,058	$ (27,700)	$ 194,758
Unrealized financial derivatives gain (loss)						
Crude oil	$ 36,253	$100,098	$ (63,845)	$ (92,871)	$ 57,752	$ (150,623)
Natural gas	3,510	2,528	982	(1,137)	287	(1,424)
Foreign currency	3,249	(10,295)	13,544	1,829	(4,177)	6,006
Interest and financing(1)	(5,778)	6,357	(12,135)	(498)	22,325	(22,823)
Total	$ 37,234	$ 98,688	$ (61,454)	$ (92,677)	$ 76,187	$ (168,864)
Total financial derivatives gain (loss)						
Crude oil	$ 72,881	$ 97,287	$ (24,406)	$ 100,568	$ 44,500	$ 56,068
Natural gas	4,087	2,573	1,514	5,477	(1,484)	6,961
Foreign currency	(8,804)	(11,576)	2,772	(31,166)	(8,724)	(22,442)
Interest and financing(1)	(5,778)	2,248	(8,026)	(498)	14,195	(14,693)
Total	$ 62,386	$ 90,532	$ (28,146)	$ 74,381	$ 48,487	$ 25,894

(1) Unrealized interest and financing derivative gain (loss) includes the change in fair value of the call options embedded in our senior unsecured notes.

The realized financial derivative gains of $25.2 million and $167.1 million for the three and nine months ended September 30, 2015, respectively, relate mainly to crude oil prices being at levels significantly below those set in our fixed price contracts, partially offset by losses on our foreign exchange contracts.

The unrealized gain of $37.2 million for the three months ended September 30, 2015 is mainly due to the decline of commodity prices at September 30, 2015 compared to June 30, 2015. The unrealized loss of $92.7 million for the nine months ended September 30, 2015 is mainly due to the realization or reversal of unrealized gains previously recorded at December 31, 2014 on our commodity contracts.

A summary of the financial derivative contracts in place as at September 30, 2015 and the accounting treatment thereof are disclosed in note 17 to the consolidated financial statements.

Operating Netback

($ per boe except for volume)	Three Months Ended September 30 2015 Canada	2015 U.S.	2015 Total	2014 Canada	2014 U.S.	2014 Total
Production volume (boe/d)	43,229	38,941	82,169	56,753	37,384	94,137
Operating netback:						
Oil and natural gas revenue	$ 29.06	$ 40.72	$ 34.59	$ 67.93	$ 78.28	$ 72.04
Other income	0.69	–	0.36	–	–	–
Less:						
Royalties	3.88	11.74	7.61	13.45	23.46	17.43
Production and operating expenses	12.31	7.97	10.25	12.70	9.39	11.39
Transportation expenses	2.88	–	1.52	3.92	–	2.36
Operating netback before financial derivatives	$ 10.68	$ 21.01	$ 15.57	$ 37.86	$ 45.43	$ 40.86
Realized financial derivatives gain (loss)(1)	–	–	3.33	–	–	(0.47)
Operating netback after financial derivatives	$ 10.68	$ 21.01	$ 18.90	$ 37.86	$ 45.43	$ 40.39

($ per boe except for volume)	Nine Months Ended September 30 2015 Canada	2015 U.S.	2015 Total	2014 Canada	2014 U.S.	2014 Total
Production volume (boe/d)	45,993	39,847	85,840	56,938	16,780	73,718
Operating netback:						
Oil and natural gas revenue	$ 32.23	$ 42.73	$ 37.10	$ 69.29	$ 80.99	$ 71.97
Other income	0.60	–	0.32	–	0.11	0.02
Less:						
Royalties	4.55	12.41	8.20	14.50	24.59	16.80
Production and operating expenses	13.13	7.58	10.55	12.79	9.84	12.12
Transportation expenses	3.37	–	1.81	4.26	–	3.29
Operating netback before financial derivatives	$ 11.78	$ 22.74	$ 16.86	$ 37.74	$ 46.67	$ 39.78
Realized financial derivatives gain (loss)(1)	–	–	7.13	–	–	(0.97)
Operating netback after financial derivatives	$ 11.78	$ 22.74	$ 23.99	$ 37.74	$ 46.67	$ 38.81

(1) Financial derivatives reflect realized gains on commodity-related contracts only.

U.S. RESULTS – IMPACT OF 2014 ACQUISITION AND DISPOSITION ACTIVITY

In 2015, the U.S. division is comprised of the Eagle Ford assets. The results of operations for the U.S. division in 2014 includes the Bakken assets in North Dakota, which were disposed of on September 24, 2014, and the Eagle Ford assets in Texas, which were acquired on June 11, 2014. This table demonstrates the impact of the 2014 acquisition and disposition activity on the U.S. results.

	Three Months Ended September 30					
	2015			2014		
Daily Production	Eagle Ford	North Dakota	Total	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	**22,983**	**–**	**22,983**	22,313	3,183	25,496
NGL	**7,522**	**–**	**7,522**	5,310	145	5,455
Total liquids (bbl/d)	**30,505**	**–**	**30,505**	27,623	3,328	30,951
Natural gas (mcf/d)	**50,613**	**–**	**50,613**	37,578	1,019	38,597
Total production (boe/d)	**38,941**	**–**	**38,941**	33,886	3,498	37,384
($ thousands except for % and per boe amounts)						
Revenue	**$ 145,895**	**$ –**	**$ 145,895**	$ 240,630	$ 28,604	$ 269,234
Royalties	**42,058**	**–**	**42,058**	71,788	8,903	80,691
Production and operating expenses	**28,544**	**–**	**28,544**	27,649	4,665	32,314
Operating income	**$ 75,293**	**$ –**	**$ 75,293**	$ 141,193	$ 15,036	$ 156,229
Realized price per boe	**$ 40.72**	**$ –**	**$ 40.72**	$ 77.19	$ 88.89	$ 78.28
Average royalty rate	**28.8%**	**–%**	**28.8%**	29.8%	31.1%	30.0%
Production and operating expenses per boe	**$ 7.97**	**$ –**	**$ 7.97**	$ 8.87	$ 14.50	$ 9.39

	Nine Months Ended September 30					
	2015			2014		
Daily Production	Eagle Ford	North Dakota	Total	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	**24,305**	**–**	**24,305**	8,890	3,015	11,905
NGL	**7,220**	**–**	**7,220**	2,096	157	2,253
Total liquids (bbl/d)	**31,525**	**–**	**31,525**	10,986	3,172	14,158
Natural gas (mcf/d)	**49,934**	**–**	**49,934**	14,812	921	15,733
Total production (boe/d)	**39,847**	**–**	**39,847**	13,455	3,326	16,780
($ thousands except for % and per boe amounts)						
Revenue	**$ 464,852**	**$ –**	**$ 464,852**	$ 288,121	$ 83,327	$ 371,448
Royalties	**134,974**	**–**	**134,974**	85,557	27,068	112,625
Production and operating expenses	**82,465**	**–**	**82,465**	31,385	13,703	45,088
Operating income	**$ 247,413**	**$ –**	**$ 247,413**	$ 171,179	$ 42,556	$ 213,735
Realized price per boe	**$ 42.73**	**$ –**	**$ 42.73**	$ 78.33	$ 91.78	$ 81.10
Average royalty rate	**29.0%**	**–%**	**29.0%**	29.7%	32.5%	30.4%
Production and operating expenses per boe	**$ 7.58**	**$ –**	**$ 7.58**	$ 8.54	$ 15.09	$ 9.84

Exploration and Evaluation Expense

Exploration and evaluation expense includes the write-off of undeveloped lands and other assets and will vary period to period depending on the scheduled expiry of leases and our assessment of the development potential of undeveloped land.

Exploration and evaluation expense was $2.0 million and $6.5 million for the three and nine months ended September 30, 2015, respectively, compared to $1.6 million and $16.1 million for the three and nine months ended September 30, 2014. Exploration and evaluation expense for the three months ended September 30, 2015 was consistent with the same period of 2014. The decrease for the nine months ended September 30, 2015 is primarily related to a decrease in expiration of undeveloped lands.

Depletion and Depreciation

	Three Months Ended September 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation(1)	$ 65,525	$ 95,827	$ 162,503	$ 78,573	$ 92,582	$ 172,024
Depletion and depreciation per boe	$ 16.48	$ 26.75	$ 21.50	$ 15.05	$ 26.92	$ 19.86

	Nine Months Ended September 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation(1)	$ 208,354	$ 287,030	$ 498,106	$ 237,029	$ 121,048	$ 360,208
Depletion and depreciation per boe	$ 16.59	$ 26.39	$ 21.26	$ 15.25	$ 26.42	$ 17.90

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $162.5 million and $498.1 million for the three and nine months ended September 30, 2015, respectively, decreased $9.5 million and increased $137.9 million from the same periods in 2014. The decrease of $9.5 million for three months ended September 30, 2015 compared to the same period in 2014 is mainly due to lower production volumes in Canada. The increase of $137.9 million in the nine months ended September 30, 2015 compared to the same period in 2014 is mainly due to increased production with the acquisition of the Eagle Ford assets, slightly offset by lower production volumes due to reduced capital spending in Canada combined with the North Dakota disposition. Depletion and depreciation per boe for the three and nine months ended September 30, 2015 of $21.50/boe and $21.26/boe, respectively, increased from $19.86/boe and $17.90/boe for same periods in 2014, mainly due to the Eagle Ford assets which have higher costs per boe included in the depletable pool.

Impairment

During the three months ended September 30, 2015, an impairment expense of $493.2 million was recorded. The impairment charge was recorded on our Eagle Ford assets and is directly attributable to lower commodity prices. The Eagle Ford assets were originally recorded at their fair value at the time of acquisition in June of 2014 when WTI oil price was more than US$100/bbl. Commodity prices have declined in 2015 and the future market prices have also decreased which has reduced estimated future cash flows for our U.S. operations below the carrying amount of the assets. The impairment resulted in a $210.3 million reduction to oil and gas properties and a write off of the remaining $282.9 million of goodwill associated with this acquisition. We have determined that no impairments are required on our Canadian cash-generating units. There were no impairments in the corresponding periods in 2014.

The recoverable amount of each cash-generating unit was determined using the discounted cash flows for proved, probable and, in the case of the U.S. assets, possible reserves as well as the fair value of undeveloped land acreage. In computing the future cash flows of the assets, we made certain assumptions, most significantly about future commodity prices and the discount rate. We assumed a WTI price of approximately US$55/bbl in 2016, US$70/bbl in 2017 and US$75/bbl in 2018. It is possible that commodity prices in those years may be lower than the current estimate which could result in further impairments. A 10% before tax discount rate has been applied to total proved, probable and possible reserves after applying a 50% risk factor to possible reserves to reflect the lower probability of recovery.

General and Administrative Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for % and per boe)	**2015**	2014	Change	**2015**	2014	Change
General and administrative expenses	**$ 13,976**	$ 16,770	(17%)	**$ 46,588**	$ 42,978	8%
General and administrative expenses per boe	**$ 1.85**	$ 1.94	(5%)	**$ 1.99**	$ 2.14	(7%)

General and administrative ("G&A") expenses for the three months ended September 30, 2015 were $14.0 million, a decrease of $2.8 million from the same period in 2014. G&A expenses have decreased as a result of reductions to staffing levels to coincide with lower activity levels combined with a reduction of all discretionary spending. G&A expenses for the nine months ended September 30, 2015 increased slightly to $46.6 million from $43.0 million in 2014. This increase is attributable to the acquisition of the Eagle Ford assets and associated office in Houston.

On a per boe basis, general and administrative expenses have decreased in 2015 from 2014 for both the three and nine month comparative periods with the reduction in discretionary spending and the low incremental G&A costs associated with the Eagle Ford assets.

Share-based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan was $3.2 million and $19.4 million for the three and nine months ended September 30, 2015, respectively, compared to $6.9 million and $22.9 million for the same periods in 2014. The decrease in share-based compensation expense during 2015 is a result of the lower fair value of share awards granted in 2015 combined with higher forfeitures during the period as compared to 2014.

Financing Costs

Financing costs include interest on bank loan and long-term debt, non-cash charges related to accretion of asset retirement obligations and the amortization of loan and debt financing costs.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for %)	**2015**	2014	Change	**2015**	2014	Change
Bank loan	**$ 2,361**	$ 9,174	(74%)	**$ 9,785**	$ 16,644	(41%)
Long-term debt	**22,680**	20,352	11%	**66,053**	39,547	67%
Accretion on asset retirement obligations and other	**2,501**	1,786	40%	**7,886**	5,307	49%
Financing costs	**$ 27,542**	$ 31,312	(12%)	**$ 83,724**	$ 61,498	36%

Financing costs decreased by $3.8 million to $27.5 million for the three months ended September 30, 2015 compared to $31.3 million in 2014 mainly due to lower outstanding bank debt levels as a result of the $606 million of equity financing completed in April 2015. For the nine months ended September 30, 2015, financing costs were $83.7 million representing an increase of 36% compared to 2014. The increase is mainly a result of the interest on US$800 million of senior unsecured notes that were issued in conjunction with the Eagle Ford acquisition in June 2014.

Foreign Exchange

Unrealized foreign exchange gains and losses are due to the change in the value of the bank loan and long-term debt denominated in U.S. dollars. 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 September 30			Nine Months Ended September 30		
($ thousands except for % and exchange rates)	**2015**	2014	Change	**2015**	2014	Change
Unrealized foreign exchange loss	**$ 89,215**	$ 54,937	62%	**$172,182**	$ 40,014	330%
Realized foreign exchange (gain) loss	**(1,696)**	2,109	(180%)	**(1,583)**	3,095	(151%)
Foreign exchange loss	**$ 87,519**	$ 57,046	53%	**$170,599**	$ 43,109	296%
CAD/USD exchange rates:						
At beginning of period	**1.2474**	1.0676		**1.1601**	1.0636	
At end of period	**1.3394**	1.1208		**1.3394**	1.1208	

The unrealized foreign exchange loss of $89.2 million and $172.2 million for the three and nine months ended September 30, 2015, respectively, was due to our U.S. dollar denominated senior unsecured notes (US$950 million principal amount) which have increased in value as the Canadian dollar weakened against the U.S. dollar at September 30, 2015 as compared to both June 30, 2015 and December 31, 2014. The realized foreign exchange gains for the three and nine months ended September 30, 2015 was due to day-to-day U.S. dollar denominated transactions as the U.S. dollar strengthened relative to the Canadian dollar over these periods.

Income Taxes

($ thousands)	Three Months Ended September 30 2015	2014	Change	Nine Months Ended September 30 2015	2014	Change
Current income tax expense	$ 178	$ 52,461	$ (52,283)	$ 16,560	$ 52,461	$ (35,901)
Deferred income tax (recovery) expense	(91,858)	(11,157)	(80,701)	(145,853)	28,923	(174,776)
Total income tax (recovery) expense	$ (91,680)	$ 41,304	$ (132,984)	$ (129,293)	$ 81,384	$ (210,677)

For the three months ended September 30, 2015, current income tax expense of $0.2 million decreased by $52.3 million, as compared to $52.5 million for the same period in 2014. This decrease primarily relates to the gain on disposition of the North Dakota assets which resulted in current income tax expense of $52.5 million in 2014. For the nine months ended September 30, 2015, current income tax expense of $16.6 million decreased by $35.9 million compared to the same period in 2014. This decrease primarily relates to the gain on disposition of the North Dakota assets which resulted in current income tax expense of $52.5 million in 2014. This was partially offset by the increase in realized financial derivative gains recorded in 2015 and the increase in previously deferred income being taxed in 2015.

Deferred income tax recovery of $91.9 million and $145.9 million for the three months and nine months ended September 30, 2015, respectively, have increased from a recovery of $11.2 million and an expense of $28.9 million for the same periods of 2014. These increases are primarily due to the impairment on oil and gas properties in 2015, the increase in unrealized financial derivative losses and the decrease in income deferred for taxation purposes in the future years.

In 2014, the Canada Revenue Agency ("CRA") advised Baytex that it was proposing to reassess certain subsidiaries of Baytex to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. Baytex has filed its 2014 income tax return and intends to file its future tax returns on the same basis as the 2011 through 2013 tax returns, cumulatively claiming $591 million of non-capital losses. The Company believes that it should be entitled to deduct the non-capital losses, that its tax filings to-date are correct, and has formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a reply to Baytex's letter. The Company expects to continue to defend the position as filed.

Net Income (Loss)

Net loss for the three months ended September 30, 2015 totaled $517.9 million compared to net income of $144.4 million in 2014. The decrease in 2015 was mainly due to an impairment charge of $493.2 million combined with lower operating netbacks, lower financial derivative gains and higher unrealized foreign exchange losses on U.S. dollar denominated debt partially offset by an income tax recovery compared to the prior period.

Net loss for the nine months ended September 30, 2015 totaled $720.7 million compared to net income of $229.0 million in 2014. The decrease in 2015 was due to an impairment charge of $493.2 million combined with lower operating netbacks, higher unrealized foreign exchange losses on U.S. dollar denominated debt, higher depletion expenses and financing costs, partially offset by higher financial derivative gains and an income tax recovery compared to the prior period.

Other Comprehensive Income

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. operations not recognized in profit or loss. The foreign currency translation gain of $217.1 million for the three months ended September 30, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at September 30, 2015 (1.3394 CAD/USD) compared to the exchange rate on June 30, 2015 (1.2474 CAD/USD). The foreign currency translation gain of $416.4 million for the nine months ended September 30, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at September 30, 2015 (1.3394 CAD/USD) compared to the exchange rate on December 31, 2014 (1.1601 CAD/USD).

Capital Expenditures

In the first nine months of 2015, our capital program has been significantly curtailed in response to low commodity prices with only minimal capital expenditures occurring and planned in Canada. In the U.S., activity levels have also slowed compared to the last half of 2014.

Capital expenditures for the three and nine months ended September 30, 2015 and 2014 are summarized as follows:

	Three Months Ended September 30					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	$ 33,484	$ 93,320	$ 126,804	$ 76,621	$ 153,411	$ 230,032
Acquisitions, net of divestitures(1)	(586)	89	(498)	(388)	(341,520)	(341,908)
Total oil and natural gas capital expenditures	$ 32,898	$ 93,409	$ 126,306	$ 76,233	$ (188,109)	$ (111,876)

	Nine Months Ended September 30					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	$ 62,446	$ 317,797	$ 380,243	$ 328,994	$ 222,379	$ 551,373
Acquisitions, net of divestitures(1)	2,234	(12)	2,222	8,349	2,572,470	2,580,819
Total oil and natural gas capital expenditures	$ 64,680	$ 317,785	$ 382,465	$ 337,343	$2,794,849	$3,132,192

(1) Includes divestiture-related expenses.

During the three months ended September 30, 2015, exploration and development expenditures were $126.8 million, representing a $103.2 decrease from the same period in 2014. Exploration and development expenditures in Canada were $33.5 million for the third quarter, up $25.8 million from the second quarter of 2015. We experienced a slight recovery in commodity prices at the start of the third quarter as a a result we initiated our Canadian drilling program but subsequently curtailed the program as commodity prices declined throughout the quarter. In the third quarter of 2015, we drilled 29.5 net wells (20.3 in Canada and 9.2 in the Eagle Ford) compared to 41.4 net wells (24.0 in Canada, 14.9 in the Eagle Ford and 2.5 in North Dakota) for the same period in 2014.

During the nine months ended September 30, 2015, exploration and development expenditures were $380.2 million, representing a $171.1 million decrease from the same period in 2014. In the first nine months of 2015, we drilled 69.8 net wells (31.4 in Canada and 38.4 in the Eagle Ford) compared to 188.8 net wells (163.8 in Canada, 17.8 in the Eagle Ford and 7.2 in North Dakota) for the same period in 2014. Capital expenditures decreased $266.6 million in Canada and increased $95.5 million in the U.S. during the nine months ended September 30, 2015 compared to the same period in 2014. Increased spending associated with the Eagle Ford assets accounted for the increase compared to 2014 which included our North Dakota assets, which was disposed of on September 24, 2014. In Canada, the reduction in capital spending of $266.6 million is mainly attributable to the drop in commodity prices during 2015 compared to the same period in 2014.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends (net of DRIP) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate our ability to generate the cash flow necessary to fund capital investments and dividends.

The following table reconciles cash flow from operating activities (a GAAP measure) to funds from operations (a non-GAAP measure).

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands except for %)	**2015**	2014	**2015**	2014
Cash flow from operating activities	**$ 167,643**	$ 347,102	**$ 543,741**	$ 620,796
Change in non-cash working capital	**(39,470)**	(24,094)	**(52,768)**	57,846
Asset retirement expenditures	**2,273**	3,894	**9,879**	10,782
Financing costs	**(27,542)**	(31,312)	**(83,724)**	(61,498)
Accretion on asset retirement obligations	**1,602**	1,786	**4,768**	5,307
Accretion on long-term debt	**546**	588	**1,426**	1,044
Funds from operations	**$ 105,052**	$ 297,964	**$ 423,322**	$ 634,277
Dividends declared	**$ 41,550**	$ 119,785	**$ 153,973**	$ 298,509
Reinvested dividends	**(24,302)**	(30,014)	**(57,349)**	(69,899)
Cash dividends declared (net of DRIP)	**$ 17,248**	$ 89,771	**$ 96,624**	$ 228,610
Payout ratio	**40%**	40%	**36%**	47%
Payout ratio (net of DRIP)	**16%**	30%	**23%**	36%

Baytex does not deduct capital expenditures when calculating the payout ratio. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, there can be no certainty that we will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $17.2 million and $96.6 million for the three and nine months ended September 30, 2015, respectively, were funded by funds from operations of $105.1 million and $423.3 million. In response to the prolonged low price commodity environment, Baytex suspended the monthly dividend beginning September 2015.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

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

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

The current commodity price environment has reduced our internally generated funds from operations. As a result, we have taken several steps to protect our liquidity, which included reducing our 2015 capital program capital program by approximately 40% from our initial plans and working with our lending syndicate to relax certain financial covenants on our credit facilities. On April 2, 2015, we closed an equity financing whereby we issued 36,455,000 common shares at a price of $17.35 per share for aggregate gross proceeds of approximately $632.5 million. The net proceeds, after issuance costs, of approximately $606.0 million were utilized to pay down a portion of our credit facilities. We also announced the suspension of our monthly dividend starting in September of 2015.

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

The following table summarizes our total monetary debt at September 30, 2015 and December 31, 2014.

($ thousands)	September 30, 2015	December 31, 2014
Bank loan[(1)]	$ 208,195	$ 666,886
Long-term debt[(1)]	1,581,002	1,418,685
Working capital deficiency[(2)(3)]	160,539	210,409
Total monetary debt	$ 1,949,736	$ 2,295,980

(1) Principal amount of instruments.

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

(3) In the oil and gas industry, it is not unusual to have a working capital deficiency as accounts receivable arising from sales of production are usually settled within one or two months but accounts payable related to capital and operating expenditures are usually settled over a longer time span (often two to four months) due to vendor billing cycles and internal approval processes.

At September 30, 2015, total monetary debt was $1,949.7 million, representing a decrease of $342.7 million compared to $2,296.0 million at December 31, 2014. The decrease at September 30, 2015 is primarily attributable to the equity proceeds of US$606 million which were applied to outstanding bank debt. This was partially offset by the revaluation of our U.S. dollar denominated monetary debt and additional draws on the bank loan to fund the capital expenditure program. The impact of the movement in exchange rates since December 2014 has resulted in an aggregate increase in bank loan and long-term debt of $190.6 million.

Bank Loan

Baytex has revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a $50 million operation loan, a $950 million syndicated loan and a US$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the “Revolving Facilities”). On May 25, 2015, Baytex reached an agreement with its lending syndicate to extend the revolving period under the Revolving Facilities to June 4, 2019 (from June 4, 2018).

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). At September 30, 2015, $208.2 million was drawn on the Revolving Facilities leaving approximately $1,059.7 million in undrawn credit capacity. Copies of the agreements relating to the Revolving Facilities are accessible on the SEDAR website at www.sedar.com (filed under the categories “Other material contracts” on June 11, 2014, September 9, 2014 and February 24, 2015 and “Material contracts – Credit agreements” on May 27, 2015).

Long-term Debt

Baytex has four series of senior unsecured notes outstanding that total $1.58 billion at September 30, 2015. The senior unsecured notes have varying interest rates and maturities as follows:

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

Pursuant to the acquisition of Aurora Oil & Gas Limited ("Aurora") on June 11, 2014, we assumed all of Aurora's existing senior unsecured notes and then purchased and cancelled approximately 98% of the outstanding notes. On February 27, 2015, we redeemed one tranche of the remaining Aurora notes at a price of US$8.3 million plus accrued interest. The remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, commencing on April 1, 2016 at specified redemption prices.

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

On 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. These notes are redeemable at our option, in whole or in part, commencing on February 17, 2016 at specified redemption prices.

Covenants

The following table lists the financial covenants under the Revolving Facilities and the senior unsecured notes, and the compliance therewith as at September 30, 2015.

Covenant Description		Position as at September 30, 2015
Revolving Facilities	**Maximum Ratio**	
Senior debt to Capitalization(1)(2)	0.65:1.00	0.40:1.00
Senior debt to Bank EBITDA(1)(5)	4.75:1.00	2.29:1.00
Total debt to Bank EBITDA(3)(5)	4.75:1.00	2.29:1.00
Senior Unsecured Notes	**Minimum Ratio**	
Fixed charge coverage(4)	2:50:1.00	7.02:1.00

(1) "Senior debt" is defined as the sum of the principal amount of our bank loan and principal amount of long-term debt.

(2) "Capitalization" is defined as the sum of the principal amount of our bank loan, principal amount of long-term debt and shareholders' equity.

(3) "Total debt" is defined as the sum of the principal amount of our bank loan, principal amount of long-term debt, and certain other liabilities identified in the credit agreement.

(4) Fixed charge coverage is computed as the ratio of financing costs to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended September 30, 2015 was $787.5 million.

(5) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income for financing costs, income taxes, certain specific unrealized and non-cash transactions (including depletion, depreciation, amortization, impairment, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange, and share-based compensation), and acquisition and disposition activity and is calculated based on a trailing twelve month basis.

On February 20, 2015, we reached an agreement with our lending syndicate to amend the financial covenants contained in the Revolving Facilities as follows: a) the maximum Senior Debt to capitalization ratio will be 0.65:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 0.55:1.00 thereafter; b) the maximum Senior Debt to Bank EBITDA ratio will be 4.75:1.00 for the period December 31, 2014 up to and including

June 30, 2016, 4.50:1.00 for the period July 1, 2016 up to and including December 31, 2016, and 3.50:1.00 thereafter; and c) the maximum Total Debt to Bank EBITDA will be 4.75:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 4.00:1.00 thereafter. If we exceed or breach any of the covenants under the Revolving Facilities or our senior unsecured notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from paying dividends to our shareholders.

Financial Instruments

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

A summary of the risk management contracts in place as at September 30, 2015 and the accounting treatment thereof is disclosed in note 17 to the consolidated financial statements.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. As at October 30, 2015, we had 210,264,243 common shares and no preferred shares issued and outstanding. During the nine months ended September 30, 2015, shares were issued through the equity financing, the DRIP and our share-based compensation programs.

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 the Company's funds from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of September 30, 2015 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	**$ 260,141**	$ 260,141	$ –	$ –	$ –
Bank loan[1][2]	**208,195**	–	–	208,195	–
Long-term debt[2]	**1,581,002**	–	–	8,572	1,572,430
Operating leases	**52,112**	8,006	16,333	15,830	11,943
Processing agreements	**56,325**	10,230	12,369	9,043	24,683
Transportation agreements	**75,379**	13,427	23,369	22,618	15,965
Total	**$ 2,233,154**	$ 291,804	$ 52,071	$ 264,258	$ 1,625,021

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

(2) Principal amount of instruments.

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

OFF BALANCE SHEET TRANSACTIONS

Baytex does not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 2015, nor are any such arrangements outstanding as of the date of this MD&A.

QUARTERLY FINANCIAL INFORMATION

	2015			2014				2013
($ thousands, except per common share amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Gross revenues	**268,625**	345,432	285,615	472,394	634,415	476,404	385,809	330,712
Net income (loss)	**(517,856)**	(26,955)	(175,916)	(361,816)	144,369	36,799	47,841	31,173
Per common share – basic	**(2.49)**	(0.13)	(1.04)	(2.16)	0.87	0.27	0.38	0.26
Per common share – diluted	**(2.49)**	(0.13)	(1.04)	(2.16)	0.86	0.27	0.38	0.25

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", "project", "plan", "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 2015; our capital expenditures for 2015; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; the proposed reassessment of our tax filings by the CRA to deny non-capital loss deductions for taxation years 2011 through 2013, including our intention to file tax returns for subsequent taxation years in a manner consistent with previous filings, our view of our tax filing position and our intention to defend the proposed reassessments if issued by the CRA; our ability to sustain our operations and planned capital expenditures utilizing internally generated funds from operations and our existing undrawn credit facilities; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; and the existence, operation and strategy of our risk management program, including our intent of partially mitigating some of the volatility in our funds from operations through a series of derivative contracts. 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.

Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

These forward-looking statements are based on certain key assumptions regarding, among other things: our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; 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; 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; the amount of future cash dividends that we intend to pay; 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; substantial or extended declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the capital markets that may restrict the availability of or increase the cost of capital or of borrowing; refinancing risk for existing debt and the risk of failing to comply with covenants in existing debt agreements; risks associated with properties operated by third parties, specifically with respect to a substantially majority of our Eagle Ford assets; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; 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 hazards associated with acquiring, developing and exploring for oil and natural gas; business risks; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and 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, 2014, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	September 30, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	$ 233	$ 1,142
Trade and other receivables	99,264	203,259
Crude oil inventory	105	262
Financial derivatives	76,587	220,146
	176,189	424,809
Non-current assets		
Financial derivatives	9,604	498
Exploration and evaluation assets (note 4)	522,911	542,040
Oil and gas properties (note 5)	5,158,971	4,983,916
Other plant and equipment	26,084	34,268
Goodwill (note 6)	–	245,065
	$ 5,893,759	$ 6,230,596
LIABILITIES		
Current liabilities		
Trade and other payables	$ 260,141	$ 398,261
Dividends payable to shareholders	–	16,811
Financial derivatives	13,062	54,839
	273,203	469,911
Non-current liabilities		
Bank loan (note 7)	204,314	663,312
Long-term debt (note 8)	1,560,065	1,399,032
Asset retirement obligations (note 9)	269,003	286,032
Deferred income tax liability	845,110	905,532
	3,151,695	3,723,819
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 10)	4,283,851	3,580,825
Contributed surplus	21,653	31,067
Accumulated other comprehensive income	615,950	199,575
Deficit	(2,179,390)	(1,304,690)
	2,742,064	2,506,777
	$ 5,893,759	$ 6,230,596

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Revenues, net of royalties (note 14)	$ 211,122	$ 483,493	$ 707,576	$1,158,544
Expenses				
Production and operating	77,490	98,625	247,325	243,955
Transportation and blending	15,880	30,931	64,892	114,419
Exploration and evaluation (note 4)	2,003	1,637	6,549	16,145
Depletion and depreciation	162,503	172,024	498,106	360,208
Impairment (note 5 & 6)	493,227	–	493,227	–
General and administrative	13,976	16,770	46,588	42,978
Acquisition-related costs	–	–	–	36,973
Share-based compensation (note 11)	3,209	6,854	19,442	22,941
Financing costs (note 15)	27,542	31,312	83,724	61,498
Financial derivatives (gain) (note 17)	(62,386)	(90,532)	(74,381)	(48,487)
Foreign exchange loss (note 16)	87,519	57,046	170,599	43,109
Divestiture of oil and gas properties (gain) loss	(305)	(26,847)	1,525	(45,588)
	820,658	297,820	1,557,596	848,151
Net income (loss) before income taxes	(609,536)	185,673	(850,020)	310,393
Income tax (recovery) expense (note 13)				
Current income tax expense	178	52,461	16,560	52,461
Deferred income tax (recovery) expense	(91,858)	(11,157)	(145,853)	28,923
	(91,680)	41,304	(129,293)	81,384
Net income (loss) attributable to shareholders	$ (517,856)	$ 144,369	$ (720,727)	$ 229,009
Other comprehensive income				
Foreign currency translation adjustment	217,122	155,498	416,375	108,373
Comprehensive income (Loss)	$ (300,734)	$ 299,867	$ (304,352)	$ 337,382
Net income (loss) per common share (note 12)				
Basic	$ (2.49)	$ 0.87	$ (3.71)	$ 1.60
Diluted	$ (2.49)	$ 0.86	$ (3.71)	$ 1.59
Weighted average common shares (note 12)				
Basic	207,988	166,189	194,143	142,730
Diluted	207,988	167,300	194,143	144,222

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2013	$ 2,004,203	$ 53,081	$ 1,484	$ (776,283)	**$ 1,282,485**
Dividends to shareholders	–	–	–	(298,509)	**(298,509)**
Exercise of share rights	18,759	(10,692)	–	–	**8,067**
Vesting of share awards	32,266	(32,266)	–	–	**–**
Share-based compensation	–	22,941	–	–	**22,941**
Issued for cash	1,495,044	–	–	–	**1,495,044**
Issuance costs, net of tax	(78,468)	–	–	–	**(78,468)**
Issued pursuant to dividend reinvestment plan	68,677	–	–	–	**68,677**
Accumulated other comprehensive income recognized on disposition of foreign operation	–	–	(15,442)	–	**(15,442)**
Comprehensive income for the period	–	–	108,373	229,009	**337,382**
Balance at September 30, 2014	$ 3,540,481	$ 33,064	$ 94,415	$ (845,783)	**$ 2,822,177**
Balance at December 31, 2014	3,580,825	31,067	199,575	(1,304,690)	**2,506,777**
Dividends to shareholders	–	–	–	(153,973)	**(153,973)**
Vesting of share awards	28,856	(28,856)	–	–	**–**
Share-based compensation	–	19,442	–	–	**19,442**
Issued for cash	632,494	–	–	–	**632,494**
Issuance costs, net of tax	(19,301)	–	–	–	**(19,301)**
Issued pursuant to dividend reinvestment plan	60,977	–	–	–	**60,977**
Comprehensive income (loss) for the period	–	–	416,375	(720,727)	**(304,352)**
Balance at September 30, 2015	$ 4,283,851	$ 21,653	$ 615,950	$ (2,179,390)	**$ 2,742,064**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands of Canadian dollars) (unaudited)	**2015**	2014	**2015**	2014
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the period	**$ (517,856)**	$ 144,369	**$ (720,727)**	$ 229,009
Adjustments for:				
Share-based compensation (note 11)	**3,209**	6,854	**19,442**	22,941
Unrealized foreign exchange loss (note 16)	**89,215**	54,937	**172,182**	40,014
Exploration and evaluation	**2,003**	1,637	**6,549**	16,145
Depletion and depreciation	**162,503**	172,024	**498,106**	360,208
Impairment (note 5 & 6)	**493,227**	–	**493,227**	–
Unrealized financial derivatives (gain) loss (note 17)	**(37,234)**	(98,688)	**92,677**	(76,187)
Divestitures of oil and gas properties (gain) loss	**(305)**	(26,847)	**1,525**	(45,588)
Current income tax expense on divestitures	**–**	52,461	**–**	52,461
Deferred income tax (recovery) expense	**(91,858)**	(11,157)	**(145,853)**	28,923
Financing costs (note 15)	**27,542**	31,312	**83,724**	61,498
Change in non-cash working capital	**39,470**	24,094	**52,768**	(57,846)
Asset retirement obligations settled (note 9)	**(2,273)**	(3,894)	**(9,879)**	(10,782)
	167,643	347,102	**543,741**	620,796
Financing activities				
Payment of dividends	**(26,655)**	(89,770)	**(109,806)**	(217,407)
Increase (decrease) in bank loan	**2,989**	(333,027)	**(479,593)**	248,860
Net proceeds from issuance of long-term debt	**–**	–	**–**	849,944
Tender of long-term debt	**–**	–	**(10,372)**	(793,099)
Issuance of common shares related to share rights (note 10)	**–**	3,345	**–**	8,067
Issuance of common shares, net of issue costs (note 10)	**–**	–	**606,095**	1,401,317
Interest paid	**(18,732)**	(19,492)	**(69,082)**	(48,952)
	(42,398)	(438,944)	**(62,758)**	1,448,730
Investing activities				
Additions to exploration and evaluation assets (note 4)	**(834)**	(2,735)	**(4,532)**	(11,883)
Additions to oil and gas properties (note 5)	**(125,970)**	(227,297)	**(375,711)**	(539,490)
Property acquisitions, net of divestitures	**498**	341,908	**(2,222)**	332,129
Corporate acquisition	**–**	–	**–**	(1,866,307)
Current income tax expense on divestiture	**–**	–	**(8,181)**	–
Additions to other plant and equipment, net of disposals	**425**	(1,843)	**5,131**	(6,704)
Change in non-cash working capital	**399**	(33,466)	**(97,408)**	6,742
	(125,482)	76,567	**(482,923)**	(2,085,513)
Impact of foreign currency translation on cash balances	**196**	276	**1,031**	772
Change in cash	**(41)**	(14,999)	**(909)**	(15,215)
Cash, beginning of period	**274**	18,152	**1,142**	18,368
Cash, end of period	**$ 233**	$ 3,153	**$ 233**	$ 3,153

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at September 30, 2015 and December 31, 2014 and for the three and nine months ended September 30, 2015 and 2014

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

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2014. The Company's accounting policies are unchanged compared to December 31, 2014. The use of estimates and judgments is also consistent with the December 31, 2014 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on November 5, 2015.

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

3. SEGMENTED FINANCIAL INFORMATION

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

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada.
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the state of Texas, USA and, for the comparative period, the state of North Dakota, USA. The Texas assets were acquired on June 11, 2014. The North Dakota assets were sold on September 24, 2014.
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Revenues, net of royalties	$ 107,285	$ 294,950	$ 103,837	$ 188,543	$ –	$ –	$ 211,122	$ 483,493
Expenses								
Production and operating	48,946	66,311	28,544	32,314	–	–	77,490	98,625
Transportation and blending	15,880	30,931	–	–	–	–	15,880	30,931
Exploration and evaluation	2,003	1,043	–	594	–	–	2,003	1,637
Depletion and depreciation	65,525	78,573	95,827	92,582	1,151	869	162,503	172,024
Impairment	–	–	493,227	–	–	–	493,227	–
General and administrative	–	–	–	–	13,976	16,770	13,976	16,770
Share-based compensation	–	–	–	–	3,209	6,854	3,209	6,854
Financing costs	–	–	–	–	27,542	31,312	27,542	31,312
Financial derivatives (gain)	–	–	–	–	(62,386)	(90,532)	(62,386)	(90,532)
Foreign exchange loss	–	–	–	–	87,519	57,046	87,519	57,046
Divestiture of oil and gas properties (gain)	(305)	–	–	(26,847)	–	–	(305)	(26,847)
	132,049	176,858	617,598	98,643	71,011	22,319	820,658	297,820
Net income (loss) before income taxes	(24,764)	118,092	(513,761)	89,900	(71,011)	(22,319)	(609,536)	185,673
Income tax expense								
Current income tax (recovery) expense	(1,852)	–	2,030	52,461	–	–	178	52,461
Deferred income tax (recovery) expense	64,820	39,199	(147,892)	(43,755)	(8,786)	(6,601)	(91,858)	(11,157)
	62,968	39,199	(145,862)	8,706	(8,786)	(6,601)	(91,680)	41,304
Net income (loss)	$ (87,732)	$ 78,893	$ (367,899)	$ 81,194	$ (62,225)	$ (15,718)	$ (517,856)	$ 144,369
Total oil and natural gas capital expenditures[1]	$ 32,897	$ 76,233	$ 93,409	$ (188,109)	$ –	$ –	$ 126,306	$ (111,876)

(1) Includes acquisitions and divestitures.

Nine Months Ended September 30	Canada 2015	Canada 2014	U.S. 2015	U.S. 2014	Corporate 2015	Corporate 2014	Consolidated 2015	Consolidated 2014
Revenues, net of royalties	$ 377,698	$ 899,721	$ 329,878	$ 258,823	$ –	$ –	$ 707,576	$1,158,544
Expenses								
Production and operating	164,860	198,867	82,465	45,088	–	–	247,325	243,955
Transportation and blending	64,892	114,419	–	–	–	–	64,892	114,419
Exploration and evaluation	6,549	9,116	–	7,029	–	–	6,549	16,145
Depletion and depreciation	208,354	237,029	287,030	121,048	2,722	2,131	498,106	360,208
Impairment	–	–	493,227	–	–	–	493,227	–
General and administrative	–	–	–	–	46,588	42,978	46,588	42,978
Acquisition-related costs	–	–	–	–	–	36,973	–	36,973
Share-based compensation	–	–	–	–	19,442	22,941	19,442	22,941
Financing costs	–	–	–	–	83,724	61,498	83,724	61,498
Financial derivatives (gain)	–	–	–	–	(74,381)	(48,487)	(74,381)	(48,487)
Foreign exchange loss	–	–	–	–	170,599	43,109	170,599	43,109
Divestiture of oil and gas properties loss (gain)	1,769	(18,741)	(244)	(26,847)	–	–	1,525	(45,588)
	446,424	540,690	862,478	146,318	248,694	161,143	1,557,596	848,151
Net income (loss) before income taxes	(68,726)	359,031	(532,600)	112,505	(248,694)	(161,143)	(850,020)	310,393
Income tax expense								
Current income tax expense	12,673	–	3,887	52,461	–	(322,286)	16,560	52,461
Deferred income tax (recovery) expense	24,711	102,157	(129,631)	(37,283)	(40,933)	(35,951)	(145,853)	28,923
	37,384	102,157	(125,744)	15,178	(40,933)	(358,237)	(129,293)	81,384
Net income (loss)	$ (106,110)	$ 256,874	$ (406,856)	$ 97,327	$ (207,761)	$ 197,094	$ (720,727)	$ 229,009
Total oil and natural gas capital expenditures(1)	$ 64,680	$ 337,343	$ 317,785	$2,794,849	$ –	$ –	$ 382,465	$3,132,192

(1) Includes acquisitions and divestitures.

As at	September 30, 2015	December 31, 2014
Canadian assets	$ 2,169,764	$ 2,398,241
U.S. assets	3,627,090	3,598,192
Corporate assets	96,905	234,163
Total consolidated assets	$ 5,893,759	$ 6,230,596

4. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2013	**$ 162,987**
Capital expenditures	15,824
Corporate acquisition	391,127
Property acquisition	12,489
Exploration and evaluation expense	(17,743)
Transfer to oil and gas properties	(10,443)
Divestitures	(40,306)
Foreign currency translation	28,105
As at December 31, 2014	**$ 542,040**
Capital expenditures	4,532
Property acquisition	1,746
Exploration and evaluation expense	(6,549)
Transfer to oil and gas properties	(82,729)
Divestitures	(663)
Foreign currency translation	64,534
As at September 30, 2015	**$ 522,911**

5. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2013	**$ 3,223,768**
Capital expenditures	750,247
Corporate acquisition	2,520,612
Property acquisitions	85,600
Transferred from exploration and evaluation assets	10,443
Change in asset retirement obligations	69,844
Divestitures	(426,477)
Foreign currency translation	197,723
As at December 31, 2014	**$ 6,431,760**
Capital expenditures	375,711
Property acquisitions	526
Transferred from exploration and evaluation assets	82,729
Change in asset retirement obligations	(15,039)
Divestitures	(911)
Impairment	(210,285)
Foreign currency translation	484,783
As at September 30, 2015	**$ 7,149,274**

Accumulated depletion	
As at December 31, 2013	**$ 1,000,982**
Depletion for the period	532,825
Divestitures	(96,916)
Foreign currency translation	10,953
As at December 31, 2014	**$ 1,447,844**
Depletion for the period	494,918
Foreign currency translation	47,541
As at September 30, 2015	**$ 1,990,303**

Carrying value	
As at December 31, 2014	**$ 4,983,916**
As at September 30, 2015	**$ 5,158,971**

Due to the decline in current and forecast commodity prices, the Company recorded total impairments of $493.2 million ($419.0 million net of tax) on its U.S. assets. The impairment was recorded as a reduction to goodwill of $282.9 million and $210.3 million to oil and gas properties. The recoverable amount for the USA cash generating unit ("CGU") was not sufficient to support the carrying amounts of the assets resulting in the impairment at September 30, 2015. No impairment was recorded for the three and nine months ended September 30, 2014. The recoverable amount of oil and gas properties was estimated based on their value in use at September 30, 2015 using the estimated discounted cash flows from the Company's best estimate of reserves utilizing a pre-tax discount rate of 10%.

For the impairment test at September 30, 2015, the Company's estimate of reserves incorporated the December 31, 2014 independent reserve report updated for recent activity and cost structure changes. The key estimates incorporated into the discounted cash flows include reserves, commodity prices and the discount rate.

The following commodity price estimates were used to determine the discounted cash flows. Prices and costs subsequent to 2020 have been adjusted for estimated annual inflation of 1.5%.

	2016	2017	2018	2019	2020
WTI crude oil (US$/bbl)	55.00	70.00	75.00	80.00	81.20
LLS oil (US$/bbl)	58.05	73.09	78.14	83.18	84.43
AECO natural gas ($/MMBtu)	3.10	3.32	3.91	4.49	4.79
Exchange rate (CAD/USD)	1.28	1.18	1.18	1.18	1.18

6. GOODWILL

As at December 31, 2013	**$ 37,755**
Acquired goodwill	615,338
Impairment	(449,590)
Foreign currency translation	41,562
As at December 31, 2014	**$ 245,065**
Impairment	(282,941)
Foreign currency translation	37,876
As at September 30, 2015	**$ –**

At September 30, 2015, due to the decline in current and forecast commodity prices, the Company recorded total impairments of $493.2 million ($419.0 million net of tax) on its USA CGU. The impairment was recorded as a reduction to goodwill of $282.9 million and $210.3 million to oil and gas properties. The recoverable amount of the USA CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment. No impairment was recorded for the three and nine months ended September 30, 2014.

7. BANK LOAN

	September 30, 2015	December 31, 2014
Bank loan	**$ 204,314**	$ 663,312

Baytex has established revolving extendible unsecured credit facilities with its bank lending syndicate that include a $50 million operating loan and a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities"). On May 25, 2015, Baytex reached an agreement with its lending syndicate to extend the revolving period under the Revolving Facilities to June 4, 2019 (from June 4, 2018).

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants and do not require any mandatory principal payments prior to maturity on June 4, 2019. In the event that Baytex exceeds or breaches any of the covenants under the Revolving Facilities, its ability to pay dividends to its shareholders, borrow funds or increase the facilities may be restricted. Baytex is in compliance with all covenants at September 30, 2015.

The weighted average interest rate on the bank loan was 4.17% for the three months ended September 30, 2015 (three months ended September 30, 2014 – 3.42%) and 3.21% for the nine months ended September 30, 2015 (nine months ended September 30, 2014 – 3.52%).

8. LONG-TERM DEBT

	September 30, 2015	December 31, 2014
9.875% notes (US$7,900 – principal) due February 15, 2017	$ –	$ 9,737
7.500% notes (US$6,400 – principal) due April 1, 2020	9,321	8,167
6.750% notes (US$150,000 – principal) due February 17, 2021	199,032	172,207
5.125% notes (US$400,000 – principal) due June 1, 2021	530,011	458,554
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	295,259	294,859
5.625% notes (US$400,000 – principal) due June 1, 2024	526,442	455,508
Total long-term debt	**$ 1,560,065**	$ 1,399,032

On February 27, 2015, the Company redeemed all of the outstanding 9.875% notes due February 15, 2017 for US$8.3 million plus accrued interest.

Interest is payable semi-annually on each series of notes outstanding. The notes are redeemable in accordance with the redemption provisions contained within each of the respective indenture agreements.

9. ASSET RETIREMENT OBLIGATIONS

	September 30, 2015	December 31, 2014
Balance, beginning of period	$ 286,032	$ 221,628
Liabilities incurred	3,738	18,516
Liabilities settled	(9,879)	(14,528)
Liabilities divested, net of acquisitions	138	(21,817)
Accretion	4,767	7,251
Change in estimate[(1)]	5,052	31,599
Changes in discount rates and inflation rates	(23,967)	42,763
Foreign currency translation	3,122	620
Balance, end of period	**$ 269,003**	$ 286,032

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

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 September 30, 2015, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2013	**125,392**	**$ 2,004,203**
Issued on exercise of share rights	683	11,298
Transfer from contributed surplus on exercise of share rights	–	14,369
Transfer from contributed surplus on vesting and conversion of share awards	842	35,108
Issued for cash	38,433	1,495,044
Issuance costs, net of tax	–	(78,468)
Issued pursuant to dividend reinvestment plan	2,757	99,271
Balance, December 31, 2014	**168,107**	**$ 3,580,825**
Transfer from contributed surplus on vesting and conversion of share awards	734	28,856
Issued for cash	36,455	632,494
Issuance costs, net of tax	–	(19,301)
Issued pursuant to dividend reinvestment plan	4,929	60,977
Balance, September 30, 2015	**210,225**	**$ 4,283,851**

On April 2, 2015, Baytex issued 36,455,000 common shares for aggregate gross proceeds of approximately $632.5 million, $606.0 million net of issue costs. Issuance costs of $26.4 million ($19.3 million, after tax) were incurred and recorded as a reduction to shareholders' capital.

Baytex has a dividend reinvestment plan that allows eligible holders in Canada and the United States to reinvest their monthly cash dividends to acquire additional common shares. During the nine months ended September 30, 2015, a total of 4,928,529 common shares were issued in accordance with this plan.

11. EQUITY-BASED PLANS

Share Award Incentive Plan

The Company recorded compensation expense related to the share awards of $3.2 million for the three months ended September 30, 2015 (three months ended September 30, 2014 – $6.9 million) and $19.4 million for the nine months ended September 30, 2015 (nine months ended September 30, 2014 – $22.9 million).

The estimated weighted average fair value for the share awards at the measurement date is $17.17 per award granted during the nine months ended September 30, 2015 (nine months ended September 30, 2014 – $43.79 per award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Total number of share awards *(000s)*
Balance, December 31, 2013	**723**	**580**	**1,303**
Granted	533	483	1,016
Vested and converted to common shares	(320)	(258)	(578)
Forfeited	(189)	(190)	(379)
Balance, December 31, 2014	**747**	**615**	**1,362**
Granted	611	495	1,106
Vested and converted to common shares	(292)	(228)	(520)
Forfeited	(159)	(73)	(232)
Balance, September 30, 2015	**907**	**809**	**1,716**

12. NET INCOME (LOSS) PER SHARE

	Three Months Ended September 30					
	2015			2014		
	Net loss	Common shares *(000s)*	Net loss per share	Net income	Common shares *(000s)*	Net income per share
Net income (loss) – basic	$ (517,856)	207,988	$ (2.49)	$ 144,369	166,189	$ 0.87
Dilutive effect of share awards	–	–	–	–	928	–
Dilutive effect of share rights	–	–	–	–	183	–
Net income (loss) – diluted	$ (517,856)	207,988	$ (2.49)	$ 144,369	167,300	$ 0.86

	Nine Months Ended September 30					
	2015			2014		
	Net loss	Common shares *(000s)*	Net loss per share	Net income	Common shares *(000s)*	Net income per share
Net income (loss) – basic	$ (720,727)	194,143	$ (3.71)	$ 229,009	142,730	$ 1.60
Dilutive effect of share awards	–	–	–	–	1,258	–
Dilutive effect of share rights	–	–	–	–	234	–
Net income (loss) – diluted	$ (720,727)	194,143	$ (3.71)	$ 229,009	144,222	$ 1.59

The number of anti-dilutive share awards for the three and nine months ended September 30, 2015 was 1.7 million.

13. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2015	2014
Net income (loss) before income taxes	$ (850,020)	$ 310,393
Expected income taxes at the statutory rate of 26.23%(1) (2014 – 25.47%)	(222,960)	79,057
Increase (decrease) in income taxes resulting from:		
Share-based compensation	5,100	6,309
Non-taxable portion of foreign exchange loss	22,340	2,829
Effect of change in income tax rates(1)	10,621	287
Effect of rate adjustments for foreign jurisdictions	(57,119)	(1,254)
Effect of change in deferred tax benefit not recognized	34,414	1,521
Impairment	74,215	–
Other	4,096	(7,365)
Income tax (recovery) expense	$ (129,293)	$ 81,384

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Alberta (from 10% to 12%), offset by a decrease in the Texas franchise tax rate (from 1.00% to 0.75%).

In 2014, the Canada Revenue Agency ("the CRA") advised Baytex that it was proposing to reassess certain subsidiaries of Baytex to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. Baytex has filed its 2014 income tax return and intends to file its future tax returns on the same basis as the 2011 through 2013 tax returns, cumulatively claiming $591 million of non-capital losses. The Company believes that it is entitled to deduct the non-capital losses and that its tax filings to-date are correct. The Company has formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a reply to Baytex's letter. The Company expects to continue to defend the position as filed.

14. REVENUES

	Three Months Ended September 30		Nine Months Ended September 30	
	2015	2014	2015	2014
Petroleum and natural gas revenues	$ 265,413	$ 633,266	$ 890,321	$ 1,492,588
Royalty expenses	(57,503)	(150,922)	(192,096)	(338,083)
Royalty income	498	1,151	1,776	3,626
Other income	2,714	(2)	7,575	413
Revenues, net of royalties	$ 211,122	$ 483,493	$ 707,576	$ 1,158,544

15. FINANCING COSTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2015	2014	2015	2014
Bank loan	$ 2,361	$ 9,174	$ 9,785	$ 16,644
Long-term debt	22,680	20,352	66,053	39,547
Accretion on asset retirement obligations and other	2,501	1,786	7,886	5,307
Financing costs	$ 27,542	$ 31,312	$ 83,724	$ 61,498

16. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2015	2014	2015	2014
Unrealized foreign exchange loss	$ 89,215	$ 54,937	$ 172,182	$ 40,014
Realized foreign exchange (gain) loss	(1,696)	2,109	(1,583)	3,095
Foreign exchange loss	$ 87,519	$ 57,046	$ 170,599	$ 43,109

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company had in place the following currency derivative contracts relating to operations as at November 5, 2015:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	October 2015 to December 2015	US$8.50 million	1.0953	(1)
Monthly average rate forward	October 2015 to December 2015	US$9.00 million	1.1094	(1)
Monthly range forward spot sale	October 2015 to December 2015	US$1.00 million	1.1000-1.1674	(2)(3)
Contingent monthly forward spot sale	October 2015 to December 2015	US$1.00 million	1.1674	(2)(4)

(1) Based on the weighted average contract rates (CAD/USD).

(2) Actual contract rate (CAD/USD).

(3) Settlement at or below the lower end of the price collar results in settlement at the lower end of the price collar. Settlement above the lower end of the price collar results in settlement at the higher end of the price collar.

(4) Settlement required if settlement price is above the strike price; contract entered into simultaneously with monthly average range forward contract or monthly range forward spot sale.

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

	Assets		Liabilities	
	September 30, 2015	December 31, 2014	**September 30, 2015**	December 31, 2014
U.S. dollar denominated	**US$114,447**	US$329,716	**US$1,210,566**	US$1,295,391

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives are governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities. The Company has applied netting to Producer 3-way options. Baytex manages these contracts based on the net exposure to market risk. As at September 30, 2015, $6.4 million of gross liabilities have been netted against assets (nil at December 31, 2014).

Financial Derivative Contracts

Baytex had the following financial derivative contracts as at November 5, 2015:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	October 2015 to December 2015	6,000 bbl/d	US$85.65	WTI
Fixed – Sell	October 2015 to March 2016	1,000 bbl/d	US$65.33	WTI
Fixed – Sell	October 2015 to June 2016	2,000 bbl/d	US$62.50	WTI
Producer 3-way option(2)	October 2015 to December 2016	1,000 bbl/d	US$62.50/US$50/US$40	WTI
Fixed – Sell	January 2016 to December 2016	5,000 bbl/d	US$63.79	WTI
Producer 3-way option(2)	January 2016 to December 2016	4,600 bbl/d	US$59.67/US$50/US$40	WTI
Basis swap	January 2016 to December 2016	2,000 bbl/d	WTI less US$13.00	WCS
Fixed – Sell(3)	November 2015 to December 2015	1,000 bbl/d	US$50.98	WTI
Producer 3-way option(2)(3)	January 2016 to December 2016	1,900 bbl/d	US$60/US$50/US$40	WTI
Producer 3-way option(2)(3)	January 2016 to December 2017	2,000 bbl/d	US$60/US$50/US$40	WTI

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

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

(3) Contracts entered subsequent to September 30, 2015.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	October 2015 to December 2015	10,000 mmBtu/d	US$3.03	NYMEX
Fixed – Sell	October 2015 to December 2015	20,000 GJ/d	$2.88	AECO
Fixed – Sell	October 2015 to December 2016	5,000 mmBtu/d	US$3.13	NYMEX
Fixed – Sell	January 2016 to December 2016	5,000 mmBtu/d	US$3.25	NYMEX
Fixed – Sell	January 2016 to December 2016	15,000 GJ/d	$2.96	AECO

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2015	2014	2015	2014
Realized financial derivatives (gain) loss	$ (25,152)	$ 8,156	$ (167,058)	$ 27,700
Unrealized financial derivatives (gain) loss – commodity	(43,012)	(96,357)	92,179	(61,780)
Unrealized financial derivatives (gain) loss – redemption feature on long-term debt	5,778	(2,331)	498	(14,407)
Financial derivatives loss (gain)	$ (62,386)	$ (90,532)	$ (74,381)	$ (48,487)

Physical Delivery Contracts

As at September 30, 2015, 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; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Price/Unit[1]
WCS Blend	October 2015 to December 2015	1,026 bbl/d	WTI less US$12.50

At September 30, 2015, Baytex had committed at fixed price to deliver the volumes of raw bitumen at noted below to market on rail:

	Period	Term Volume
Raw bitumen	October 2015 to December 2015	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
DRIP	Dividend Reinvestment Plan
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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

James L. Bowzer
President and Chief Executive Officer
Baytex Energy Corp.

John A. Brussa(3)(4)
Vice Chairman
Burnet, Duckworth & Palmer LLP

Edward Chwyl(2)(3)(4)
Lead Independent Director
Baytex Energy Corp.
Independent Businessman

Naveen Dargan(1)(2)
Independent Businessman

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

Gregory K. Melchin(1)
Independent Businessman

Mary Ellen Peters(1)(2)
Independent Businesswoman

Dale O. Shwed(3)
President & Chief Executive Officer
Crew Energy Inc.

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

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

OFFICERS

James L. Bowzer
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 Business Unit

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

Cameron A. Hercus
Vice President, Corporate Development

Ryan M. Johnson
Vice President, Central Business Unit

Chad L. Kalmakoff
Vice President, Finance

Gregory A. Sawchenko
Vice President, Land

AUDITORS

Deloitte LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company L.P.

TRANSFER AGENT

Computershare

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE