

BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three months ended March 31, 2015 and 2014
Dated May 4, 2015

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2015. This information is provided as of May 4, 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 first 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 months ended March 31, 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 other operating items. 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 traditional 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 our 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 monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)), 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. See "Liquidity, Capital Resources and Risk Management" for a calculation of total monetary debt.

Operating Netback

We define operating netback as product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales 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.

FIRST QUARTER HIGHLIGHTS

The first quarter of 2015 was marked by very low commodity prices. During the quarter, the price of West Texas Intermediate oil ("WTI") averaged US\$48.64/bbl, down more than 50% from the first quarter of 2014. Prices for natural gas were 40% lower over the same period. Our hedging contracts mitigated some of the drop in commodity prices as we realized financial derivative gains of \$108.0 million on our oil contracts during the quarter.

Average production for the three months ended March 31, 2015 was 90,710 boe/d, an increase of 52% or 31,207 boe/d, compared to the same period in 2014. This increase is primarily due to the inclusion of production from the Eagle Ford acquisition which closed in June 2014. Eagle Ford production of 41,076 boe/d in the current quarter increased 8% from 38,051 boe/d in the fourth quarter of 2014 and reflects continued growth from the successful development program. Canadian production of 49,634 boe/d decreased 12% or 6,776 boe/d primarily due to declines resulting from reduced capital spending over the past nine months, combined with approximately 700 boe/d of production that we have shut-in for economic reasons in the current quarter and approximately 1,250 boe/d related to properties divested in late 2014. First quarter production in the U.S. in the prior year related to the North Dakota assets which were disposed in the third quarter of 2014.

Revenue in the first quarter of 2015 was \$285.6 million, 26% lower than the first quarter of 2014 and 40% lower than the fourth quarter of 2014 as the drop in commodity prices more than offset the production increases.

We reduced capital spending in the first quarter of 2015 to \$147.4 million, down 31% from the fourth quarter of 2014 and \$25.0 million from the \$172.4 million spent in the first quarter of 2014. These reductions were in response to the sharp drop in crude oil prices and were achieved by reducing drilling activity and negotiating cost reductions from service providers.

The Canadian dollar weakened against the U.S. dollar at March 31, 2015 (1.2683 CAD/USD) compared to December 31, 2014 (1.1601 CAD/USD). This resulted in an unrealized foreign exchange loss of \$101.3 million on the translation of the US\$950 million of senior unsecured notes which are denominated in U.S. dollars. The drop in the Canadian dollar also increased the reported revenues, expenses and capital expenditures on our U.S. operations as our results are reported in Canadian dollars.

Funds from operations ("FFO") for the quarter were \$160.2 million, compared to \$170.8 million for the first quarter of 2014 and \$245.5 million for the fourth quarter of 2014, with the decrease due to significantly lower commodity prices. Non-cash charges, which included unrealized hedging and foreign exchange losses and depletion expenses, resulted in a net loss of \$175.9 million for the quarter compared to net income of \$47.8 million for the first quarter of 2014.

During the quarter we amended the financial covenants contained in our credit facilities. These amendments increase our financial flexibility through to the end of 2016. An equity financing was also announced on March 11, 2015 and closed subsequent to the quarter on April 2, 2015. On closing 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 of \$606.0 million were used to reduce bank indebtedness.

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 March 31					
	2015			2014		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil ⁽¹⁾	39,261	—	39,261	45,232	—	45,232
Light oil and condensate	2,091	25,965	28,056	2,715	2,755	5,470
NGL	1,239	6,985	8,224	1,793	194	1,987
Total liquids (bbl/d)	42,591	32,950	75,541	49,740	2,949	52,689
Natural gas (mcf/d)	42,255	48,755	91,010	40,022	864	40,886
Total production (boe/d)	49,634	41,076	90,710	56,410	3,093	59,503
Production Mix						
Heavy oil	79%	—%	43%	80%	—%	76%
Light oil and condensate	4%	63%	31%	5%	89%	9%
NGL	3%	17%	9%	3%	6%	4%
Natural gas	14%	20%	17%	12%	5%	11%

(1) Heavy oil sales volumes may differ from reported production volumes due to changes in our heavy oil inventory. For the three months ended March 31, 2015, heavy oil sales volumes were 35 bbl/d lower than production volumes (three months ended March 31, 2014 - 56 bbl/d lower).

Average production for the three months ended March 31, 2015 was 90,710 boe/d, an increase of 52% or 31,207 boe/d, compared to the same period in 2014. This increase is primarily due to the inclusion of production from the Eagle Ford acquisition which closed in June 2014. Eagle Ford production of 41,076 boe/d in the current quarter increased 8% from 38,051 boe/d in the fourth quarter of 2014 and reflects continued growth from the successful development program. Canadian production of 49,634 boe/d decreased 12% or 6,776 boe/d primarily due to declines resulting from reduced capital spending over the past nine months, combined with approximately 700 boe/d of production that we have shut-in for economic reasons in the current quarter and approximately 1,250 boe/d related to properties divested in late 2014. First quarter production in the U.S. in the prior year related to the North Dakota assets which were disposed in the third quarter of 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 March 31, 2015, the price of WTI averaged US\$48.64/bbl, a 51% decrease from the average WTI price of US\$98.68/bbl in the first quarter of 2014 and a 33% decrease from US\$73.14/bbl in the fourth quarter of 2014. The low price environment was brought on by a global supply imbalance 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, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 30% for the three months ended March 31, 2015, as compared to 23% in the same period in 2014. On a dollar basis, the WCS differential discount averaged US\$14.73/bbl for the quarter, down from US\$23.13/bbl in the first quarter of 2014, as improved market access allowed Canadian heavy oil to approach pipeline parity values with international heavy oils such as Maya in the Gulf of Mexico.

Natural Gas

For the three months ended March 31, 2015, the AECO natural gas price averaged \$2.95/mcf, a 38% decrease compared to \$4.76/mcf in the first quarter of 2014. For the three months ended March 31, 2015, the NYMEX natural gas prices averaged US\$2.98/mmbtu, a 40% decrease compared to US\$4.94/mmbtu in 2014. The decrease in natural gas prices on both indices in 2015 compared to 2014 was driven by production growth in the U.S. and low winter demand.

The following table compares selected benchmark prices and our average realized selling prices for the current and prior period.

	Three Months Ended March 31		
	2015	2014	Change
Benchmark Averages			
WTI oil (US\$/bbl) ⁽¹⁾	\$ 48.64	\$ 98.68	(51)%
WCS heavy oil (US\$/bbl) ⁽²⁾	\$ 33.91	\$ 75.55	(55)%
Heavy oil differential ⁽³⁾	30%	23%	
LLS oil (US\$/bbl) ⁽⁴⁾	\$ 50.55	\$ 104.90	(52)%
CAD/USD average exchange rate	1.2308	1.1035	12 %
Edmonton par oil (\$/bbl)	\$ 51.94	\$ 100.18	(48)%
AECO natural gas price (\$/mcf) ⁽⁵⁾	\$ 2.95	\$ 4.76	(38)%
NYMEX natural gas price (US\$/mmbtu) ⁽⁶⁾	\$ 2.98	\$ 4.94	(40)%

(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) Louisiana Light Sweet ("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 March 31					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Sales Prices⁽¹⁾						
Canadian heavy oil (\$/bbl) ⁽²⁾	\$ 28.57	\$ —	\$ 28.57	\$ 71.13	\$ —	\$ 71.13
Light oil and condensate (\$/bbl)	47.84	52.70	52.34	94.57	97.03	95.81
NGL (\$/bbl)	24.18	18.49	19.35	54.85	65.87	55.92
Natural gas (\$/mcf)	2.68	3.69	3.22	5.16	7.67	5.22
Weighted average (\$/boe) ⁽²⁾	\$ 27.50	\$ 40.84	\$ 33.54	\$ 66.99	\$ 92.71	\$ 68.33

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

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

Average Realized Sales Prices

Our realized heavy oil price for the three months ended March 31, 2015 was \$28.57/bbl, or 68% of WCS, compared to \$71.13/bbl, or 85% of WCS in 2014. The decrease in realized heavy oil price was due to the overall decline in global crude oil prices while the decrease in the realized price relative to WCS was due to fixed price differentials that increase as a percentage of WCS as the price of WCS declines.

During the three months ended March 31, 2015, our Canadian average sales price for light oil and condensate was \$47.84/bbl, down 49% from \$94.57/bbl in 2014. This is largely in line with the 51% decrease in WTI prices over the same period. U.S. light oil and condensate pricing for the three months ended March 31, 2015 was \$52.70/bbl, down 46% from \$97.03/bbl in the first quarter of 2014, largely in line with the 52% decrease in the LLS benchmark over the same period.

Our realized natural gas price for the three months ended March 31, 2015 was \$3.22/mcf, down from \$5.22/mcf or 38% from the first quarter of 2014. This is consistent with the decreases in the AECO and NYMEX benchmarks of 38% and 40%, respectively, over the same periods.

Gross Revenues

(\$ thousands)	Three Months Ended March 31					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	\$ 100,856	\$ —	\$ 100,856	\$ 289,213	\$ —	\$ 289,213
Light oil and Condensate	9,001	123,156	132,157	23,106	24,062	47,168
NGL	2,697	11,625	14,322	8,854	1,144	9,998
Total oil revenue	112,554	134,781	247,335	321,173	25,206	346,379
Natural gas revenue	10,186	16,190	26,376	18,599	596	19,195
Total oil and natural gas revenue	122,740	150,971	273,711	339,772	25,802	365,574
Other income	2,231	—	2,231	—	—	—
Heavy oil blending revenue	9,673	—	9,673	20,235	—	20,235
Total petroleum and natural gas revenues	\$ 134,644	\$ 150,971	\$ 285,615	\$ 360,007	\$ 25,802	\$ 385,809

Total petroleum and natural gas revenues for the three months ended March 31, 2015 of \$285.6 million decreased \$100.2 million from the first quarter of 2014 due to the decline in commodity prices, despite the increase in production volumes. In Canada, petroleum and natural gas revenues for the three months ended March 31, 2015 totaled \$134.6 million, a decrease of \$225.4 million compared to the same period in 2014 due to lower realized prices on all products combined with a 14% reduction in liquids production volumes. Petroleum and natural gas revenues of \$151.0 million in the U.S. increased from the prior year due to the acquisition of the Eagle Ford assets which produced 41,076 boe/d in the first quarter of 2015, while U.S. revenues of \$25.8 million in the first quarter of 2014 related to production of 3,093 boe/d in North Dakota.

Heavy oil blending revenue for the three months ended March 31, 2015 of \$9.7 million was down 52% compared to 2014 primarily due to the price of blending diluent which decreased 49% over the same period.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on netbacks less capital investment and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three months ended March 31, 2015 and 2014.

(\$ thousands except for % and per boe)	Three Months Ended March 31					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	\$ 13,419	\$ 43,288	\$ 56,707	\$ 66,041	\$ 8,839	\$ 74,880
Average royalty rate ⁽¹⁾	10.9%	28.7%	20.7%	19.4%	34.3%	20.5%
Royalty rate per boe	\$ 3.01	\$ 11.71	\$ 6.95	\$ 13.02	\$ 31.76	\$ 14.00

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

Total royalties for the three months ended March 31, 2015 of \$56.7 million decreased \$18.2 million from 2014. Canadian royalties have decreased to 10.9% of revenue for the three months ended March 31, 2015, compared to 19.4% of revenue in 2014 as the Crown royalty rates are price sensitive and the lower commodity prices have resulted in lower Crown royalty rates. The Canadian royalty expense also includes a \$3.0 million credit primarily relating to a refund resulting from a change in the royalty regime applicable to certain 2014 production. The royalty rate of 28.7% on the Eagle Ford assets for the first quarter of 2015 is consistent with the 29.5% recorded in the fourth quarter of 2014 as royalty rates on our Eagle Ford assets do not vary with price. The U.S. royalty rate of 34.3% for the three months ended March 31, 2014 related to our North Dakota properties which were disposed of in September of 2014.

Production and Operating Expenses

(\$ thousands except for per boe)	Three Months Ended March 31					
	2015			2014		
	Canada	U.S. ⁽¹⁾	Total	Canada	U.S.	Total
Production and operating expenses	\$ 60,574	\$ 27,181	\$ 87,755	\$ 63,933	\$ 4,902	\$ 68,835
Production and operating expenses per boe	\$ 13.57	\$ 7.35	\$ 10.75	\$ 12.61	\$ 17.61	\$ 12.87

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

Production and operating expenses for the three months ended March 31, 2015 of \$87.8 million increased by \$18.9 million compared to the first quarter of 2014 however on a per boe basis production and operating expenses are down to \$10.75/boe for the first quarter of 2015 compared to \$12.87/boe for the same period in 2014. Although total costs are up, production and operating expenses per boe are down due to the acquisition of the Eagle Ford properties that have lower relative costs and high rates of production.

Production and operating expenses in Canada of \$60.6 million decreased 5% during the three months ended March 31, 2015 from \$63.9 million in the first quarter of 2014. This is primarily due to production being 12% lower in the first quarter of 2015 than the first quarter of 2014. On a per boe basis production and operating costs increased from \$12.61/boe in the three months ended March 31, 2014 to \$13.57/boe for current period due to the impact of fixed costs over lower production.

U.S. production and operating expenses per boe declined from \$17.61/boe in the first quarter of 2014 to \$7.35/boe in the first quarter of 2015, reflective of the shift in production to the lower cost Eagle Ford assets compared to our historic North Dakota properties. The production and operating costs related to the Eagle Ford assets have declined to \$7.35/boe from \$8.37/boe for the second half of 2014, due to cost savings negotiated from service providers and decreased workover activity.

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, the heavy oil transported through pipelines requires blending to reduce its viscosity, whereas the heavy oil transported by rail does not require blending diluent. The cost of blending diluent is recovered in the sale price of the blended product.

The following table compares our blending and transportation expenses for the three months ended March 31, 2015 and 2014.

(\$ thousands except for per boe)	Three Months Ended March 31					
	2015			2014		
	Canada	U.S. ⁽²⁾	Total	Canada	U.S.	Total
Blending expenses	\$ 9,673	\$ —	\$ 9,673	\$ 20,235	\$ —	\$ 20,235
Transportation expenses	15,949	—	15,949	24,668	—	24,668
Total transportation and blending expenses	\$ 25,622	\$ —	\$ 25,622	\$ 44,903	\$ —	\$ 44,903
Transportation expenses per boe ⁽¹⁾	\$ 3.57	\$ —	\$ 1.95	\$ 4.86	\$ —	\$ 4.61

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

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

Blending expenses of \$9.7 million for the three months ended March 31, 2015 have decreased 52% compared to 2014 mainly due to a 49% decrease in the price of blending diluent as diluent volumes remained relatively unchanged from the prior period.

Transportation expenses for the three months ended March 31, 2015 totaled \$15.9 million, a decrease of 35%, or \$8.7 million, compared to 2014. The decrease is due to lower heavy oil volumes, decreased fuel charges and trucking optimization efforts. Transportation expenses, on a per boe basis, of \$3.57/boe are comparable to \$3.51/boe in the fourth quarter of 2014.

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 a series of financial derivative contracts which are intended to reduce some of the volatility in our operating cash flow. 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 on the date the contract matures. As the forward markets for commodities and currencies fluctuate and as new contracts are executed, changes in the fair value are reported as unrealized gains or losses in the period. Contracts in place at the beginning of the period which settle during the period will give rise to the reversal of the unrealized gain or loss recorded at the beginning of the period. The following table summarizes the results of our financial derivative contracts for the three months ended March 31, 2015 and 2014.

(\$ thousands)	Three Months Ended March 31		
	2015	2014	Change
Realized financial derivatives gain (loss)			
Crude oil	\$ 108,027	\$ 1,613	\$ 106,414
Natural gas	5,728	(1,187)	6,915
Foreign currency	(11,921)	(2,035)	(9,886)
Interest	—	(4,138)	4,138
Total	\$ 101,834	\$ (5,747)	\$ 107,581
Unrealized financial derivatives gain (loss)			
Crude oil	\$ (69,579)	\$ (9,312)	\$ (60,267)
Natural gas	(4,998)	(3,036)	(1,962)
Foreign currency	(15,456)	21,161	(36,617)
Interest and financing ⁽¹⁾	1,861	4,012	(2,151)
Total	\$ (88,172)	\$ 12,825	\$ (100,997)
Total financial derivatives gain (loss)			
Crude oil	\$ 38,448	\$ (7,699)	\$ 46,147
Natural gas	730	(4,223)	4,953
Foreign currency	(27,377)	19,126	(46,503)
Interest and financing ⁽¹⁾	1,861	(126)	1,987
Total	\$ 13,662	\$ 7,078	\$ 6,584

(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 financial derivative realized gain of \$101.8 million for the three months ended March 31, 2015 relates mainly to crude oil prices being at levels significantly below those set in our fixed price contracts, partially offset by the settlement of our out-of-money foreign exchange contracts as the Canadian dollar weakened against the U.S. dollar prices set in the contracts. The unrealized mark-to-market loss of \$88.2 million for the three months ended March 31, 2015 is mainly due to realization of previously recorded unrealized gains on our commodity contracts offset slightly by lower forward commodity prices at March 31, 2015 compared to December 31, 2014 and by the weakening Canadian dollar against the U.S. dollar.

A summary of the financial derivative contracts in place as at March 31, 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 March 31					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	49,599	41,076	90,675	56,354	3,092	59,446
Operating netback ⁽¹⁾ :						
Sales price	\$ 27.50	\$ 40.84	\$ 33.54	\$ 66.99	\$ 92.71	\$ 68.33
Less:						
Royalties	3.01	11.71	6.95	13.02	31.76	14.00
Production and operating expenses	13.57	7.35	10.75	12.61	17.61	12.87
Transportation expenses	3.57	—	1.95	4.86	—	4.61
Operating netback before financial derivatives	\$ 7.35	\$ 21.78	\$ 13.89	\$ 36.50	\$ 43.34	\$ 36.85
Financial derivatives gain (loss) ⁽²⁾	—	—	12.48	—	—	(0.30)
Operating netback after financial derivatives	\$ 7.35	\$ 21.78	\$ 26.37	\$ 36.50	\$ 43.34	\$ 36.55

(1) Operating netback table includes revenues and costs associated with sulphur production.

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

Exploration and Evaluation Expense

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

Exploration and evaluation expense was \$2.4 million for the three months ended March 31, 2015. The expense of \$10.6 million in the first quarter of 2014 primarily related to North Dakota lands that were expiring.

Depletion and Depreciation

(\$ thousands except for per boe)	Three Months Ended March 31					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation ⁽¹⁾	\$ 75,117	\$ 98,384	\$ 174,127	\$ 81,446	\$ 6,610	\$ 88,593
Depletion and depreciation per boe	\$ 16.83	\$ 26.61	\$ 21.34	\$ 16.04	\$ 23.74	\$ 16.56

(1) Total includes corporate depreciation.

Depletion and depreciation expense of \$174.1 million for the three months ended March 31, 2015 increased \$85.5 million from the same period in 2014. This increase is mainly due to the acquisition of the Eagle Ford assets, slightly offset by the reduction related to the North Dakota sale combined with lower production volumes in Canada. The depletion rate per boe for the three months ended March 31, 2015 increased to \$21.34/boe from \$16.56/boe in 2014, mainly due to the higher cost Eagle Ford assets being included in the depletable pool.

General and Administrative Expenses

(\$ thousands except for % and per boe)	Three Months Ended March 31		
	2015	2014	Change
General and administrative expenses	\$ 17,055	\$ 11,899	43 %
General and administrative expenses per boe	\$ 2.09	\$ 2.22	(6)%

General and administrative expenses for the three months ended March 31, 2015 of \$17.1 million were consistent with the fourth quarter of 2014, but increased \$5.2 million compared to the first quarter of 2014. The increase over the first quarter of 2014 is due to the addition of the Houston office to support our Eagle Ford operations and higher salaries and consultant costs. On a per boe basis, general and administrative expenses have decreased during the first quarter of 2015 compared to the same period of 2014 due to both increased volumes and the low incremental overhead associated with the acquired Eagle Ford assets.

Share-based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized in income 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 remained relatively constant at \$8.0 million for the three months ended March 31, 2015 compared to \$7.9 million for the same period in 2014. Despite a lower fair value of share awards for the first three months of 2015, share-based compensation remained relatively unchanged as the expense related to the first quarter of 2014 included a larger credit for actual forfeitures, as compared to in the current period, causing the reduced expense for the first quarter of 2014.

Financing Costs

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

(\$ thousands except for %)	Three Months Ended March 31		
	2015	2014	Change
Bank loan and other	\$ 5,418	\$ 2,904	87 %
Long-term debt	22,374	7,944	182 %
Accretion on asset retirement obligations	1,618	1,741	(7)%
Financing costs	\$ 29,410	\$ 12,589	134 %

The increase in financing costs for the three months ended March 31, 2015 is due to higher outstanding debt levels compared to 2014, mainly due to the acquisition of the Eagle Ford assets in June 2014.

Foreign Exchange

Unrealized foreign exchange gains and losses are due to the change in the value of the long-term debt denominated in U.S. dollars which is caused by the movement of the Canadian dollar against the U.S. dollar during the period. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in the Canadian operations.

(\$ thousands except for % and exchange rates)	Three Months Ended March 31		
	2015	2014	Change
Unrealized foreign exchange loss	\$ 101,316	\$ 6,456	1,469%
Realized foreign exchange gain	(4,261)	(1,938)	120%
Foreign exchange loss	\$ 97,055	\$ 4,518	2,048%
CAD/USD exchange rates:			
At beginning of period	1.1601	1.0636	
At end of period	1.2683	1.1053	

The foreign exchange loss of \$97.1 million for the three months ended March 31, 2015 is primarily due to the revaluation of our U.S. dollar denominated senior unsecured notes (US\$950 million principal amount) due to the Canadian dollar weakening against the U.S. dollar.

Income Taxes

For the three months ended March 31, 2015, total income tax recovery of \$24.7 million included \$16.9 million of current income tax expense and \$41.7 million of deferred income tax recovery. For the three months ended March 31, 2014, total income tax expense of \$20.4 million related entirely to deferred income tax.

The increase in current income tax expense in the current quarter primarily relates to the increase in realized financial derivative gains and the increase in previously deferred income being taxed in the current period. The increase in deferred income tax recovery for the first quarter of 2015 (compared to an expense in 2014) primarily relates to the decrease in unrealized financial derivative gains, less income being deferred for tax purposes and the reduction in future tax pool claims enabled by the net loss during the period.

Net Income (Loss)

Net loss for the three months ended March 31, 2015 totaled \$175.9 million compared to net income of \$47.8 million in 2014. The decrease was due to lower operating netbacks, higher unrealized foreign exchange losses on U.S. denominated debt, higher depletion and financing costs, partially offset by an income tax recovery.

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 \$240.9 million foreign currency translation gain for the three months ended March 31, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at March 31, 2015 (1.2683 CAD/USD) compared to the exchange rate on December 31, 2014 (1.1601 CAD/USD). Other comprehensive income is higher in 2015 than in 2014 as the carrying value of U.S. operations is significantly higher in the current period as a result of the Eagle Ford acquisition in June 2014.

Capital Expenditures

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

Capital expenditures for the three months ended March 31, 2015 and 2014 are summarized as follows:

	Three Months Ended March 31					
	2015			2014		
(\$ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	\$ 21,272	\$ 126,157	\$ 147,429	\$ 154,569	\$ 17,856	\$ 172,425
Acquisitions, net of divestitures ⁽¹⁾	1,411	139	1,550	—	673	673
Total oil and natural gas capital expenditures	\$ 22,683	\$ 126,296	\$ 148,979	\$ 154,569	\$ 18,529	\$ 173,098

(1) Includes divestiture-related expenses.

During the three months ended March 31, 2015, exploration and development expenditures were \$147.4 million, \$25.0 million lower than the same period in 2014. The reduction is comprised of decreases of \$133.3 million, or 86%, in Canada and \$17.9 million in North Dakota, partially offset by spending of \$126.2 million related to our Eagle Ford assets. The first quarter Eagle Ford capital expenditures are 16% lower than the \$149.5 million spent during the fourth quarter of 2014. In the first three months of 2015, we drilled 25.1 net wells (9.1 in Canada and 16.0 in the Eagle Ford) compared to 119.1 net wells (116.6 in Canada and 2.5 in North Dakota) for 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 dividends and capital investments.

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

	Three Months Ended March 31	
<i>(\$ thousands except for %)</i>	2015	2014
Cash flow from operating activities	\$ 209,490	\$ 121,607
Change in non-cash working capital	(26,300)	55,980
Asset retirement expenditures	4,446	3,896
Financing costs	(29,410)	(12,589)
Accretion on asset retirement obligations	1,618	1,741
Accretion on long-term debt	377	175
Funds from operations	\$ 160,221	\$ 170,810
Dividends declared	\$ 50,649	\$ 83,257
Reinvested dividends	(9,183)	(19,816)
Cash dividends declared (net of DRIP)	\$ 41,466	\$ 63,441
Payout ratio	32%	49%
Payout ratio (net of DRIP)	26%	37%

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, we may be required to reduce or eliminate dividends on our common shares in order to fund capital expenditures. 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 \$41.5 million for the three months ended March 31, 2015 were funded by funds from operations of \$160.2 million.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

We regularly review our liquidity sources as well as our exposure to counterparties and believe 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, augmented by funds from our hedging program and our existing undrawn credit facilities, will provide sufficient liquidity to sustain our operations, dividends and planned capital expenditures. The timing of most of the capital expenditures are discretionary and there are no material long-term capital expenditure commitments. The dividend level is also discretionary, and we have the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes. Further, we believe that our counterparties 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 market environment, highlighted by unusually low commodity prices, has negative implications to our internally generated funds from operations. We have taken steps to protect our liquidity. These include a reduction of the monthly dividend from \$0.24 per share to \$0.10 per share and reducing our 2015 capital program by approximately 40% from our initial program. We have also received relaxation of certain financial covenants applicable to our credit facilities. If the current commodity price environment continues, or if prices decline further, we may need to make additional changes to the dividend level or 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 facilities or obtain new financing. It could also restrict our ability to pay 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 minimum capital expenditures required to maintain operations, we may draw the maximum funds available under 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.

On March 11, 2015, we announced an equity financing which closed subsequent to the quarter on April 2, 2015. On closing 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 bank credit facilities.

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.

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

(\$ thousands)	March 31, 2015	December 31, 2014
Bank loan ⁽¹⁾	\$ 780,447	\$ 666,886
Long-term debt ⁽¹⁾	1,513,002	1,418,685
Working capital deficiency ⁽²⁾	162,546	210,409
Total monetary debt	\$ 2,455,995	\$ 2,295,980

(1) Principal amount of instruments.

(2) Working capital is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives).

At March 31, 2015, total monetary debt was \$2,456.0 million, as compared to \$2,296.0 million at December 31, 2014. The increase in total monetary debt at March 31, 2015, as compared to December 31, 2014, was primarily due to the revaluation of our U.S. dollar denominated monetary debt and additional draws on the bank loan to fund the capital expenditure program. Subsequent to the share issuance on April 2, 2015, the net proceeds of \$606 million were used to repay a portion of the bank loan.

Bank Loan

Baytex has established revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a \$50 million operating loan and a \$950 million syndicated loan for Baytex and a US\$200 million syndicated loan for our wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments prior to maturity on June 4, 2018. 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 March 31, 2015, \$780.4 million was drawn on the Revolving Facilities leaving approximately \$473.2 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 category "Material Document" on June 11, 2014, September 9, 2014 and February 24, 2015).

Long-term Debt

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 April 1, 2016 at a specified redemption price.

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 March 31, 2015.

Covenant Description	Maximum Ratio	Position as at March 31, 2015
Revolving Facilities		
Senior debt to Capitalization ^{(1) (2)}	0.65:1.00	0.48:1.00
Senior debt to Bank EBITDA ^{(1) (5) (6)}	4.75:1.00	2.05:1.00
Total debt to Bank EBITDA ^{(3) (5) (6)}	4.75:1.00	2.05:1.00
Senior Unsecured Notes		
Fixed charge coverage ⁽⁴⁾	2:50:1.00	10.54:1.00

(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 March 31, 2015 was \$1.13 billion, including earnings of Aurora on a pro forma basis.

(5) For purposes of the covenant calculations, Aurora's Bank EBITDA for the trailing twelve months has been included, in accordance with the terms of the credit agreement.

(6) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income for financing costs, income tax, 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 (excluding acquisition-related costs incurred) 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 March 31, 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 April 30, 2015, we had 205,599,455 common shares and no preferred shares issued and outstanding. During the three months ended March 31, 2015, shares were issued through the DRIP and our share-based compensation programs. Subsequent to the quarter we issued 36,455,000 common shares on April 2, 2015 pursuant to a public offering announced on March 11, 2015.

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 March 31, 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	\$ 303,033	\$ 303,033	\$ —	\$ —	\$ —
Dividends payable to shareholders	16,900	16,900	—	—	—
Bank loan ^{(1) (2)}	780,447	—	—	780,447	—
Long-term debt ⁽²⁾	1,513,002	—	—	—	1,513,002
Operating leases	54,640	7,715	15,732	16,011	15,182
Processing agreements	61,775	11,178	14,608	9,043	26,946
Transportation agreements	77,903	12,988	23,018	21,418	20,479
Total	\$ 2,807,700	\$ 351,814	\$ 53,358	\$ 826,919	\$ 1,575,609

(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, 2018, 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.

QUARTERLY FINANCIAL INFORMATION

	2015	2014				2013		
(\$ thousands, except per common share amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Gross revenues	285,615	472,394	634,415	476,404	385,809	330,712	422,791	341,011
Net income (loss)	(175,916)	(361,816)	144,369	36,799	47,841	31,173	87,331	36,192
Per common share - basic	(1.04)	(2.16)	0.87	0.27	0.38	0.26	0.70	0.29
Per common share - diluted	(1.04)	(2.16)	0.86	0.27	0.38	0.25	0.70	0.29

INTERNAL CONTROL OVER FINANCIAL REPORTING

On June 11, 2014, Baytex completed the acquisition of Aurora Oil & Gas Limited, a publicly traded oil and gas company that was listed on the Australian and Toronto stock exchanges. The results of the acquisition of Aurora have been included in the consolidated financial statements of Baytex since June 11, 2014. However, Baytex has not had sufficient time to appropriately assess the disclosure controls and procedures and internal controls over financial reporting previously used by Aurora and integrate them with those of Baytex. In addition, Aurora was not subject to the Sarbanes-Oxley Act of 2002 and, therefore, was not required to have its external auditors audit the effectiveness of its internal control over financial reporting. As a result, the certifying officers have limited the scope of their design of disclosure controls and procedures and internal control over financial reporting to exclude controls, policies and procedures of Aurora (as permitted by applicable securities laws in Canada and the U.S.). Baytex has a program in place to complete its assessment of the controls, policies and procedures of the acquired operations by June 11, 2015.

During the three months ended March 31, 2015, the assets previously held by Aurora contributed revenues net of royalties of \$107.7 million (representing 47% of total revenues, net of royalties) and operating income of \$80.5 million (representing 68% of total operating income). At March 31, 2015, current assets of \$48.7 million, non-current assets of \$3.9 billion, current liabilities of \$150.3 million and non-current liabilities of \$1.9 billion were associated with the entity acquired.

No changes were made to our internal control over financial reporting during the three months ended March 31, 2015.

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; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the existence, operation and strategy of our risk management program, including our intent of partially mitigating some of the volatility in our funds from operations through a series of derivative contracts; our objective to fund our capital expenditures and cash dividends on our common shares with funds from operations and existing credit capacity; and the completion of our assessment of the disclosure controls and procedures and internal controls over financial reporting for the acquired Eagle Ford operations. 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.