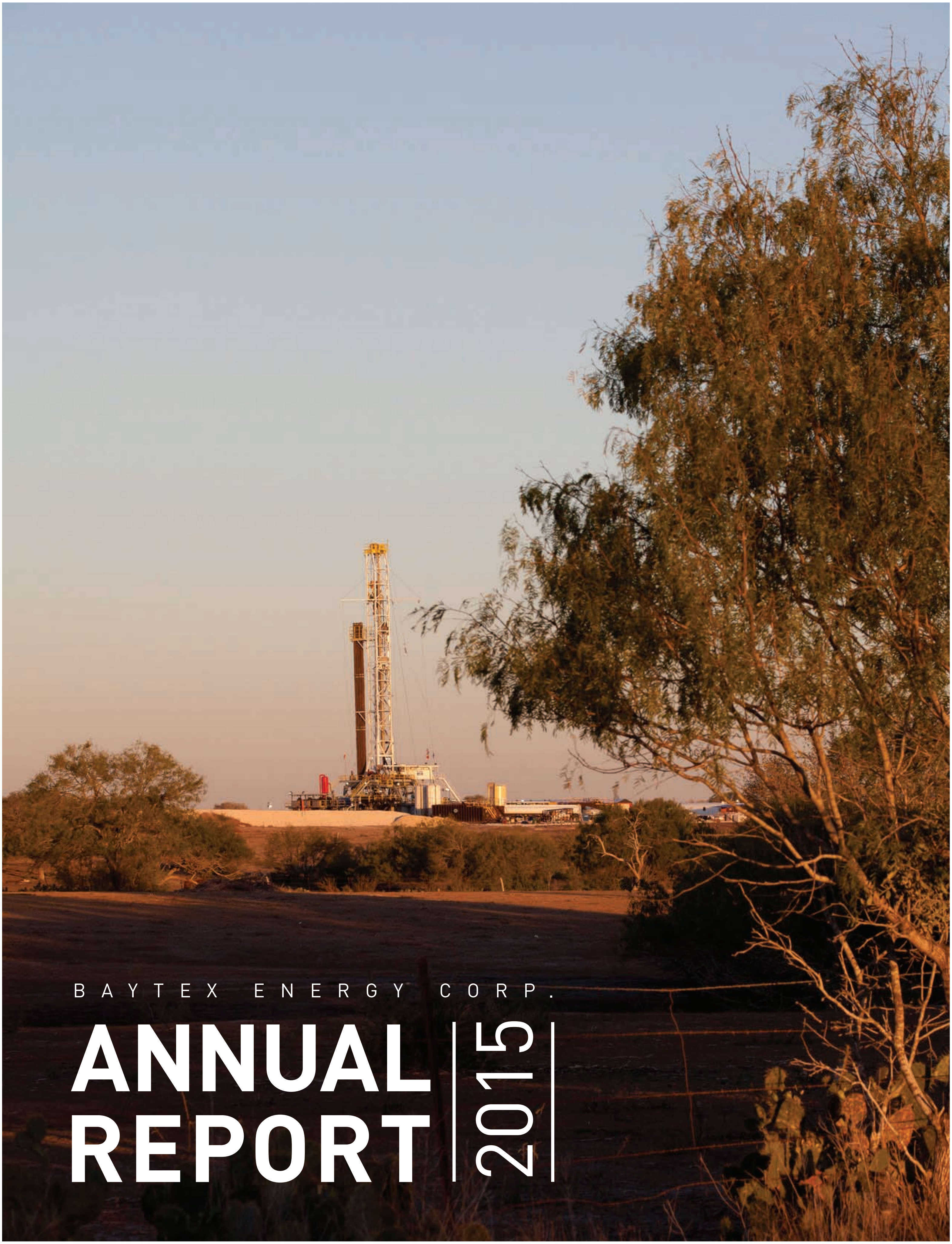

BAYTEX ENERGY CORP.

ANNUAL REPORT 2015

OPERATING AREAS

CONTENTS

SUMMARY

	Years Ended	
	December 31, 2015	December 31, 2014
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*		
Petroleum and natural gas sales	**1,129,872**	1,969,022
Funds from operations[1]	**516,417**	879,790
Per share – basic	**2.61**	5.91
Per share – diluted	**2.61**	5.91
Cash dividends declared[2]	**96,624**	301,118
Dividends declared per share	**0.80**	2.64
Net income (loss)	**(1,133,651)**	(132,807)
Per share – basic	**(5.72)**	(0.89)
Per share – diluted	**(5.72)**	(0.89)
Exploration and development	**521,039**	766,070
Acquisitions, net of divestitures	**1,648**	2,545,156
Total oil and natural gas capital expenditures	**522,687**	3,311,226
Bank loan[3]	**256,749**	666,886
Long-term notes[3]	**1,623,658**	1,418,685
Long-term debt	**1,880,407**	2,085,571
Working capital deficiency	**169,498**	210,409
Net debt[4]	**2,049,905**	2,295,980
OPERATING		
Daily production		
Heavy oil (bbl/d)	**34,974**	45,022
Light oil and condensate (bbl/d)	**25,887**	17,681
NGL (bbl/d)	**8,492**	4,819
Total oil and NGL (bbl/d)	**69,353**	67,522
Natural gas (mcf/d)	**91,766**	65,234
Oil equivalent (boe/d @ 6:1)[5]	**84,648**	78,395
Average prices (before hedging)		
WTI oil (US$/bbl)	**48.79**	92.97
WCS Heavy Oil (US$/bbl)	**35.26**	73.58
Edmonton par oil ($/bbl)	**57.20**	95.28
LLS oil (US$/bbl)	**51.50**	96.76
BTE heavy oil ($/bbl)[6]	**32.23**	69.64
BTE light oil and condensate ($/bbl)	**55.75**	91.37
BTE NGL ($/bbl)	**16.91**	35.28
BTE total oil and NGL ($/bbl)	**39.13**	72.88
BTE natural gas ($/mcf)	**3.08**	4.53
BTE oil equivalent ($/boe)	**35.40**	66.54
CAD/USD noon rate at period end	**1.3840**	1.1601
CAD/USD average rate for period	**1.2811**	1.1050

	Years Ended	
	December 31, 2015	December 31, 2014
COMMON SHARE INFORMATION		
TSX		
Share price (Cdn$)		
High	**24.87**	49.88
Low	**3.50**	14.56
Close	**4.48**	19.32
Volume traded (thousands)	**652,044**	273,743
NYSE		
Share price (US$)		
High	**20.10**	46.46
Low	**2.50**	12.63
Close	**3.24**	16.61
Volume traded (thousands)	**375,660**	33,170
Common shares outstanding (thousands)	**210,583**	168,107

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 asset retirement obligations settled. 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, debt repayment 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 year ended December 31, 2015.*

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

(3) *Principal amount of instruments.*

(4) *Net debt is a non-GAAP measure which we define to be the sum of working capital (which is current assets less current liabilities (excluding unrealized gains or losses on financial derivatives)) and the principal amount of long-term debt.*

(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 but not limited to: our business strategies, plans and objectives; our target for capital expenditures to approximate funds from operations in order to minimize any increase in our debt levels; our liquidity and financial capacity; the possibility that we may seek further relaxation of the financial covenants contained in our revolving credit facilities; our ability to continue to achieve cost reductions across all of our operations; our Eagle Ford shale play, including our belief that it is one of the premier oil resource plays in North America and that it contains a significant inventory of development prospects; our plans for developing our assets; our heavy oil assets, including our belief that they will provide attractive returns and that we have a multi-year development inventory; our exploration and development expenditures for 2016 and the portion thereof to be invested in the Eagle Ford; our reserves life index; the net present value before income taxes of the future net revenue attributable to our reserves; forecast prices for oil and natural gas; forecast inflation and exchange rates; future development costs; the value of our undeveloped land holdings; and our estimated net asset value. 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. 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.

Non-GAAP Financial Measures

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. 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 capital investments and future dividends to shareholders. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Net debt is not a measurement based on GAAP in Canada. We define net debt 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, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Bank EBITDA is not a measurement based on GAAP in Canada. We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in our credit agreements governing our unsecured revolving credit facilities. This measure is used to measure compliance with certain financial covenants.

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

MESSAGE TO SHAREHOLDERS

The year 2015 will be remembered as one of the most challenging years the oil and gas industry has faced. Global oversupply of crude oil continued to weigh on the market, ultimately pushing prices below US$30/bbl in early 2016. As the year unfolded, resource play development in North America was increasingly challenged, funds from operations declined materially, and balance sheet strength and liquidity became of paramount importance.

We were not immune to these challenges. The decline in global crude oil prices significantly stressed our business model. In order to ensure the long-term viability and success of our company, we needed to respond in a prudent fashion to this rapidly changing environment. Our priorities shifted from growing our production through the efficient development of our high quality assets and paying a meaningful dividend to our shareholders to preserving strong levels of financial liquidity.

We undertook several steps to preserve strong levels of financial liquidity in 2015, including completing an equity financing, adjusting the level and timing of capital spending, negotiating cost reductions with service providers, reducing staffing levels and suspending the monthly dividend. We believe these decisions will serve us well as we move forward.

In 2015, our exploration and development capital program totaled $521 million, which was reduced from an original budget level of $575 million to $650 million. This capital program was funded largely by our funds from operations, which totaled $516 million. We remain committed to preserving financial liquidity through this downturn, and will continue to target exploration and development capital expenditures at a level that approximates our funds from operations in order to minimize any increase in our debt levels.

Our bank lending syndicate agreed to relax the financial covenants contained in our unsecured revolving credit facilities twice during 2015. In each case, these amendments were obtained pro-actively, as we remained in compliance with our unamended financial covenants throughout 2015. We will continue to manage our credit facilities and, if the outlook for commodity prices remains low, we may seek further covenant relief.

We also realized over $150 million in efficiencies in 2015 as we remained focused on cost reductions across all of our operations, including drilling and completions, production and operating expenses, transportation expenses, and general and administrative expenses. We continue to take active measures to reduce costs while maintaining the efficiency and compliance of our operations and the integrity of our assets without compromising the safety of our employees and contractors.

Despite a reduced capital program, our operating results were consistent with our expectations. We achieved average annual production of 84,648 boe/d during 2015, in line with guidance. We also increased our proved plus probable reserves (excluding bitumen) by 2% and generated a strong recycle ratio of 2.1 times. This is a testament to the quality of our asset base.

The addition of the Eagle Ford assets to our portfolio in 2014 provided us with exposure to one of the premier oil resource plays in North America. The high quality Eagle Ford assets provide the highest cash netbacks in our portfolio and contain a significant inventory of development prospects. In 2015, we focused our development activity in the Eagle Ford, where we directed 86% of our exploration and development expenditures. Significantly, while the Eagle Ford accounted for 47% of our 2015 production, it generated approximately two-thirds of our operating netback.

In the Eagle Ford, significant advancements were made in the past year to delineate the multi-zone potential of our acreage position. We continued to implement “stack and frac” pilots which target up to three zones in the Eagle Ford formation in addition to the overlying Austin Chalk. Production in the Eagle Ford averaged 40,284 boe/d in the fourth quarter of 2015, up 6% from the fourth quarter of 2014. We replaced 205% of production, and increased our proved plus probable reserves by 8% to 203 million boe.

Production in Canada averaged 44,691 boe/d during 2015, down 21% from the prior year as commodity prices did not support a full-year capital development program combined with non-core asset dispositions and uneconomic volumes that were shut-in. We also suspended operations at our Cliffdale cyclic steam stimulation project and decommissioned our Gemini steam-assisted gravity drainage pilot project. With a modest recovery in crude oil prices, our heavy oil assets generate attractive rates of return with strong capital efficiencies. We continue to have a multi-year development inventory on these assets.

Responsible Value Creation

While the commodity price environment has required us to recalibrate our business model, it has not had an impact on the core values which drive our business decisions and the ethics we hold as a company. We believe that by acting as a responsible company in all aspects of our operations, we create long-term value for all stakeholders. We focus on employee opportunities for personal growth, an improved quality of life in communities where we operate, business opportunities for Aboriginal groups, and an attractive return on investment for shareholders. Crude oil and natural gas development can provide significant benefits to communities, landowners, suppliers and others, often in areas where limited economic development opportunities exist. In the end, everyone benefits from environmentally responsible development that produces reliable energy at a reasonable cost.

Developing crude oil and natural gas resources requires long-term commitment. Collaboration with a broad range of engaged stakeholders is important to achieve enduring success in resource development. Accordingly, we have continued our focus on stakeholder engagement, furthering the progress of our Good Neighbour Program throughout our field operations. This program strives to create social and economic benefits for the community while mitigating the impacts related to our operations; it is a real-life expression of responsible value creation. In 2015, we issued our first Good Neighbour Program Report Card as well as our second biennial Corporate Responsibility Report.

Summary

What has not changed for us through this downturn is the quality of our assets. We have built an exceptional asset base focused on crude oil and liquids with a significant inventory of development prospects. Our development program will remain flexible and allows for adjustments to spending based on changes in the commodity price environment. We currently plan to move forward in 2016 with a reduced pace of development in the Eagle Ford and will forgo any heavy oil development in Canada until prices recover.

We now anticipate exploration and development expenditures for 2016 of $225 to $265 million, of which approximately 95% will be invested in the Eagle Ford. At the mid-point, this represents a 53% reduction in capital spending relative to 2015.

Baytex's success is due to our dedicated and talented team of employees who align with our strategy, consistently execute on our plans and drive the creation of shareholder value. Complementing our leadership team and committed employees, it is important to recognize that our Board of Directors is an indispensable source of guidance and support which contribute significantly to our success.

We look forward to executing our plans for 2016 for the ongoing benefit of all stakeholders and we thank you for your continued support.

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
March 3, 2016

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 year ended December 31, 2015. This information is provided as of March 2, 2016. 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 year to date results have been compared with the corresponding period in 2014. This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2015 and 2014, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2015. 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 the MD&A for our advisory on forward-looking information and statements.

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, net debt 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

The Company considers funds from operations ("FFO") a key measure that provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investments, debt repayment and future dividends. However, funds from operations should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income (loss).

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

	Years Ended December 31	
($ thousands)	**2015**	2014
Cash flow from operating activities	**$ 549,420**	$ 897,152
Change in non-cash working capital	**(43,891)**	(31,890)
Asset retirement expenditures	**10,888**	14,528
Funds from operations	**$ 516,417**	$ 879,790

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position.

The following table summarizes our net debt at December 31, 2015 and 2014.

($ thousands)	December 31, 2015	December 31, 2014
Bank loan(1)	$ 256,749	$ 666,886
Long-term notes(1)	1,623,658	1,418,685
Working capital deficiency(2)(3)	169,498	210,409
Net debt	$ 2,049,905	$ 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.

Operating Netback

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

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants.

The following table reconciles net income (loss) (a GAAP measure) to Bank EBITDA (a non-GAAP measure).

	Years Ended December 31	
($ thousands)	2015	2014
Net income (loss)	$ (1,133,651)	$ (132,807)
Plus:		
Financing costs	111,660	90,033
Income tax expense (recovery)	(344,146)	134,391
Depletion and depreciation	661,858	536,569
EBITDA attributable to acquired assets	–	254,087
Other non-cash items(1)	1,333,007	414,898
Bank EBITDA	$ 628,728	$ 1,297,171

(1) Other non-cash items include share-based compensation, unrealized foreign exchange loss, exploration and evaluation expense, unrealized (gain) loss on financial derivatives, gain (loss) on divestiture of oil and gas properties and impairment.

YEAR END HIGHLIGHTS

2015 was a challenging year as world oil prices declined significantly from 2014 and we continually adjusted our business in response. Throughout the year, the Company took steps to protect its liquidity in order to withstand the low commodity price environment. Despite these changes, the Company was able to achieve production of 84,648 boe/d, advance the multi-zone potential of its Eagle Ford asset and achieve cost reductions in all aspects of the business.

Production for the year ended December 31, 2015 increased 8% to 84,648 boe/d mainly due to growth from the Eagle Ford assets which was partially offset by declines in Canada. U.S. production averaged 39,957 boe/d in 2015 and was 80%, or 17,819 boe/d, higher than 2014. Production from the Company's Eagle Ford assets was included for the full year in 2015 and has increased more than 11,000 boe/d since the acquisition in June of 2014. This was partially offset by the North Dakota disposition which closed on September 24, 2014. Canadian production averaged 44,691 boe/d in 2015, a decrease of 21%, from 56,257 boe/d in 2014. Reduced capital spending, property dispositions and shut-in production contributed to reduced production levels on our Canadian assets in 2015.

Funds from operations for the year ended December 31, 2015 was $516.4 million, compared to $879.8 million in 2014. The decrease in FFO was directly attributable to lower commodity prices. The Company's realized sales price of $35.40/boe decreased 47% from the prior year driven by a 48% decrease in the price of West Texas Intermediate light oil ("WTI") for the year. WTI prices averaged US$48.79/bbl in 2015 compared to US$92.97/bbl in 2014.

In response to the lower commodity prices, we continued to reduce our capital program throughout 2015 investing a total of $521.0 million for the year. Capital spending was focused on our Eagle Ford assets with 86% of total capital being spent in the U.S. Spending in the U.S. totaled $449.8 million in 2015 compared to $371.8 million in 2014 where we drilled 50.2 net wells in 2015 compared to 33.2 net wells in 2014. In the Eagle Ford, we were able to further advance the multi-zone potential of the acreage which resulted in additional reserves and enhanced economics in this play. Activity in Canada was significantly reduced in 2015 as we drilled 31.4 net wells and spent $71.3 million compared to 175.1 net wells and $394.2 million in 2014.

With the low commodity environment, we took several steps to protect our liquidity. On April 2, 2015, we completed an equity financing, issuing 36,455,000 common shares at a price of $17.35 per share for net proceeds of $606.0 million. In September, we made the difficult decision to suspend our dividend and reduce our capital program. We have also worked with our bank lending syndicate throughout 2015. We received covenant relief in early 2015, extended the maturities of our credit facilities by one year in June and negotiated further covenant relief in December. We also chose to voluntarily reduce our Canadian credit facilities by $200 million as the carrying costs were increasing and we could not see ourselves utilizing the full amount of the facility in the current environment. At December 31, 2015, the Company was in compliance with all of its financial covenants and $256.7 million was drawn on the facilities leaving approximately $820.0 million in undrawn credit capacity.

During the year, we recorded total impairment charges of $1.0 billion ($992.9 million related to Eagle Ford assets and $45.7 million to Canadian assets). The impairment charges are directly attributable to the decline in commodity prices. The Eagle Ford 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 since the date of acquisition on June 11, 2014.

Production

	Years Ended December 31					
	2015			2014		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**34,974**	**–**	**34,974**	45,022	–	45,022
Light oil and condensate	**1,828**	**24,059**	**25,887**	2,621	15,060	17,681
NGL	**1,070**	**7,422**	**8,492**	1,441	3,378	4,819
Total liquids (bbl/d)	**37,872**	**31,481**	**69,353**	49,084	18,438	67,522
Natural gas (mcf/d)	**40,911**	**50,855**	**91,766**	43,037	22,197	65,234
Total production (boe/d)	**44,691**	**39,957**	**84,648**	56,257	22,138	78,395
Production Mix						
Heavy oil	**79%**	**–%**	**41%**	79%	–%	56%
Light oil and condensate	**4%**	**61%**	**31%**	5%	68%	24%
NGL	**2%**	**19%**	**10%**	3%	15%	6%
Natural gas	**15%**	**20%**	**18%**	13%	17%	14%

Annual average production for the year ended December 31, 2015 was 84,648 boe/d, representing an 8% increase, or 6,253 boe/d, compared to 2014. The increase in 2015 is primarily due to production from the Eagle Ford acquisition. Canadian production of 44,691 boe/d decreased 21%, or 11,566 boe/d, from 2014. The Canadian decrease is attributable to natural declines associated with reduced capital spending along with non-core dispositions and uneconomic production we have shut-in which total approximately 2,900 boe/d for the year. At December 31, 2015, we had approximately 2,400 boe/d of uneconomic production shut-in. U.S. production for the year ended December 31, 2015 was 39,957 boe/d, an increase of 80% over the prior year as production from our Eagle Ford assets contributed for the full-year 2015 compared to 2014 where they were only included since the date of acquisition on June 11, 2014. This was offset by the divestiture of the North Dakota production which produced 2,483 boe/d for 2014. The Eagle Ford 2014 production for the three months ended December 31, 2014 was 38,035 boe/d.

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 year ended December 31, 2015, the WTI oil prompt averaged US$48.79/bbl, a 48% decrease from the average WTI price of US$92.97/bbl in 2014. The low prices experienced during year ended 2015, as compared to 2014, were due to a persistent global over supply of oil due in part to the decision of the Organization of Petroleum Exporting Countries (OPEC) to step away from its traditional swing producer role.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 29% for the year ended December 31, 2015, as compared to 21% in 2014. While on a percentage basis the WCS differential widened, the differential narrowed in nominal terms to average US$13.52/bbl for the year ended December 31, 2015 as compared to US$19.40/bbl in 2014. The improvement in the nominal differential was due to increased pipeline capacity from Canada to the U.S. Gulf Coast, which allows WCS pricing to achieve pipeline equivalency with the large waterborne Gulf Coast refinery market.

Natural Gas

For the year ended December 31, 2015, the AECO natural gas prices averaged $2.74/mcf, a 38% decrease compared to $4.42/mcf in 2014. For the year ended December 31, 2015, the NYMEX natural gas price averaged US$2.66/mmbtu, a 40% decrease compared to US$4.41/mmbtu in 2014. The decrease in natural gas prices on both indices during 2015 was driven by historically high production levels which exceeded current demand.

The following table compares selected benchmark prices and our average realized selling prices for the years ended December 31, 2015 and 2014.

	Years Ended December 31		
	2015	2014	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	**48.79**	92.97	(48%)
WCS heavy oil (US$/bbl)[2]	**35.26**	73.58	(52%)
Heavy oil differential[3]	**29%**	21%	
LLS oil (US$/bbl)[4]	**51.50**	96.76	(47%)
CAD/USD average exchange rate	**1.2811**	1.1050	16%
Edmonton par oil ($/bbl)	**57.20**	95.28	(40%)
AECO natural gas price ($/mcf)[5]	**2.74**	4.42	(38%)
NYMEX natural gas price (US$/mmbtu)[6]	**2.66**	4.41	(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) 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.

	Years Ended December 31					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[1]	$ 32.23	$ –	$ 32.23	$ 69.64	$ –	$ 69.64
Light oil and condensate ($/bbl)	52.52	55.99	55.75	89.88	91.63	91.37
NGL ($/bbl)	20.80	16.35	16.91	45.49	30.93	35.28
Natural gas ($/mcf)	2.59	3.47	3.08	4.49	4.62	4.53
Weighted average ($/boe)[2]	$ 30.24	$ 41.16	$ 35.40	$ 64.52	$ 71.69	$ 66.54

(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 year ended December 31, 2015 was $32.23/bbl, or 71% of WCS, compared to $69.64/bbl, or 86% of WCS in 2014. The Company's decrease in realized heavy oil price of 54% for the year ended December 31, 2015 compared to 2014 corresponds with the 52% change in WCS heavy oil price over the same period. 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 2015 compared to 2014.

During the year ended December 31, 2015, our Canadian average sales price for light oil and condensate was $52.52/bbl, down 42% from $89.88/bbl in 2014. This corresponds with the 40% decrease in the benchmark Edmonton Par prices over the same period. U.S. light oil and condensate pricing for the year ended December 31, 2015 was $55.99/bbl, down 39% from $91.63/bbl in 2014, which is consistent with a 38% decrease in the LLS benchmark (as expressed in Canadian dollars).

Our realized natural gas price for the year ended December 31, 2015 was $3.08/mcf, down from $4.53/mcf in 2014. This is largely in line with the decreases in the AECO and NYMEX benchmarks during these periods.

Gross Revenues

	Years Ended December 31					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 411,386	$ –	$ 411,386	$ 1,144,360	$ –	$ 1,144,360
Light oil and condensate	35,044	491,700	526,744	85,986	503,701	589,687
NGL	8,121	44,286	52,407	23,924	38,136	62,060
Total liquids revenue	454,551	535,986	990,537	1,254,270	541,837	1,796,107
Natural gas revenue	38,723	64,334	103,057	70,514	37,418	107,932
Total oil and natural gas revenue	493,274	600,320	1,093,594	1,324,784	579,255	1,904,039
Other income[1]	–	–	8,448	–	–	6,863
Heavy oil blending revenue	27,830	–	27,830	58,120	–	58,120
Total petroleum and natural gas revenues	$ 521,104	$ 600,320	$1,129,872	$ 1,382,904	$ 579,255	$ 1,969,022

(1) Total includes corporate other income

Total petroleum and natural gas revenues for the year ended December 31, 2015 of $1,129.9 million decreased $839.2 million from the prior year. This decrease can be attributed to the drop in commodity prices which decreased petroleum and natural gas revenues by $962 million during 2015 which was partially offset by higher production volumes which increased petroleum and natural gas revenues by $152 million. In Canada, petroleum and natural gas revenues for the year ended December 31, 2015 totaled $521.1 million, a decrease of $861.8 million compared to 2014. The lower petroleum and natural gas revenues in 2015 were due to lower production volumes and lower realized prices on all products. Petroleum and natural gas revenues of $600.3 million in the U.S. increased $21.1 million from the prior year with increased production from the acquisition of the Eagle Ford assets which was offset by the decrease in realized prices on all products.

Heavy oil blending revenue of $27.8 million for the year ended December 31, 2015 decreased $30.3 million compared to 2014. 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 purchases and sales are recorded as heavy oil blending revenue and expense, respectively. Heavy oil blending revenue decreased as the price of diluent decreased in the year and the Company sold less diluent with the decrease in heavy oil production within Canada.

Royalties

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

	Years Ended December 31					
	2015			2014		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 67,323**	**$ 174,102**	**$ 241,425**	$ 265,066	$ 174,059	$ 439,125
Average royalty rate[(1)]	**13.6%**	**29.0%**	**22.1%**	20.0%	30.0%	23.1%
Royalty rate per boe	**$ 4.13**	**$ 11.94**	**$ 7.81**	$ 12.91	$ 21.54	$ 15.35

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

Total royalties for the year ended December 31, 2015 of $241.4 million decreased 45%, or $197.7 million from 2014, mainly due to the decline in gross revenues. Canadian royalties decreased to 13.6% of revenue for the year ended December 31, 2015, compared to 20.0% of revenue in 2014. Canadian crown royalty rates are partially based on price and with the lower commodity prices during 2015 the Company experienced lower crown royalty rates compared to 2014. U.S. royalties of $174.1 million for year ended December 31, 2015 is consistent with 2014 as the slight increase in revenues during the year was offset by a slightly lower royalty rate. Royalty rates in the U.S. for 2015 have decreased to 29.0% compared to 30.0% in the prior year due to the disposition of the North Dakota assets that had a higher royalty rate than the Eagle Ford assets.

Operating Expenses

	Years Ended December 31					
	2015			2014		
($ thousands except for per boe)	**Canada**	**U.S.[(1)]**	**Total**	Canada	U.S.[(1)]	Total
Operating expenses	**$ 210,945**	**$ 109,242**	**$ 320,187**	$ 272,515	$ 81,334	$ 353,849
Operating expenses per boe	**$ 12.93**	**$ 7.49**	**$ 10.36**	$ 13.27	$ 10.07	$ 12.37

(1) Operating expenses related to the Eagle Ford assets include transportation expenses.

Operating expenses for the year ended December 31, 2015 of $320.2 million decreased $33.7 million compared to 2014. On a per boe basis, operating expenses for the year ended December 31, 2015 decreased $2.01/boe to $10.36/boe, compared to $12.37/boe in 2014. Operating expenses per boe have decreased 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 operating expenses of $210.9 million for the year ended December 31, 2015 decreased $61.6 million compared to 2014. The decrease is a result of lower production volumes and realized cost savings across all of our operations. With realized cost savings from service providers, lower fuel costs and reduced labour costs, our Canadian operating expenses per boe for the year ended December 31, 2015 decreased $0.34/boe to $12.93/boe, compared to $13.27/boe in 2014. Despite significant reductions in our operating costs, the savings per boe were somewhat offset by fixed costs on lower production volumes.

U.S. operating expenses of $109.2 million for the year ended December 31, 2015, increased $27.9 million compared to 2014 due to the increase in production. On a per boe basis, costs decreased $2.58/boe to $7.49/boe for the year ended December 31, 2015. The costs per boe have decreased with the acquisition of the Eagle Ford assets which have a lower operating cost than the North Dakota properties. Costs in the Eagle Ford have also decreased since the acquisition through lower service costs and from fixed costs being spread over a growing production base.

Transportation Expenses

Transportation expenses include the costs to move production from the field to the sales point. The largest component of transportation expenses relates to the trucking of heavy oil to pipeline and rail terminals. The following table compares our transportation expenses for the years ended December 31, 2015 and 2014.

	Years Ended December 31					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.[1]	Total	Canada	U.S.[1]	Total
Transportation expenses	$ 53,127	$ –	$ 53,127	$ 83,766	$ –	$ 83,766
Transportation expense per boe	$ 3.26	$ –	$ 1.72	$ 4.08	$ –	$ 2.93

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

Transportation expenses for the year ended December 31, 2015 totaled $53.1 million, a decrease of 36%, or $30.6 million, compared to 2014. The decrease is due to lower heavy oil volumes being transported to the sales point, decreased fuel costs and the increased use of lower cost internal trucking.

Blending Expenses

Blending expenses for the year ended December 31, 2015 of $27.8 million have decreased $30.3 million or 52%, compared to 2014. Consistent with the decrease in heavy oil blending revenue, blending expenses decreased due to a decrease in both the volume of blending diluent required and the price of blending diluent. 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.

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 years ended December 31, 2015 and 2014.

	Years Ended December 31		
($ thousands)	2015	2014	Change
Realized financial derivatives gain (loss)			
Crude oil	$ 235,393	$ 46,844	$ 188,549
Natural gas	8,549	(974)	9,523
Foreign currency	(46,397)	(10,416)	(35,981)
Interest	–	(8,130)	8,130
Total	$ 197,545	$ 27,324	$ 170,221
Unrealized financial derivatives gain (loss)			
Crude oil	$ (70,354)	$ 186,115	$ (256,469)
Natural gas	968	5,802	(4,834)
Foreign currency	15,068	(8,737)	23,805
Interest and financing	(498)	2,020	(2,518)
Total	$ (54,816)	$ 185,200	$ (240,016)
Total financial derivatives gain (loss)			
Crude oil	$ 165,039	$ 232,959	$ (67,920)
Natural gas	9,517	4,828	4,689
Foreign currency	(31,329)	(19,153)	(12,176)
Interest and financing[1]	(498)	(6,110)	5,612
Total	$ 142,729	$ 212,524	$ (69,795)

(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 gain of $197.5 million for the year ended December 31, 2015, relate mainly to crude oil prices being at levels significantly below those set in our fixed price contracts, partially offset by $15.1 million of losses on our foreign exchange contracts.

The unrealized loss of $54.8 million for the year ended December 31, 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 December 31, 2015 and the accounting treatment thereof are disclosed in note 19 to the consolidated financial statements.

Operating Netback

	Years Ended December 31					
	2015			2014		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	44,691	39,957	84,648	56,257	22,138	78,395
Operating netback:						
Oil and natural gas revenues	$ 30.24	$ 41.16	$ 35.40	$ 64.52	$ 71.69	$ 66.54
Other income	–	–	0.27	–	–	0.24
Less:						
Royalties	4.13	11.94	7.81	12.91	21.54	15.35
Operating expenses	12.93	7.49	10.36	13.27	10.07	12.37
Transportation expenses	3.26	–	1.72	4.08	–	2.93
Operating netback	$ 9.92	$ 21.73	$ 15.78	$ 34.57	$ 40.13	$ 36.13
Financial derivatives gain	–	–	6.39	–	–	1.24
Operating netback after financial derivatives	$ 9.92	$ 21.73	$ 22.17	$ 34.57	$ 40.13	$ 37.37

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 included 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.

	Years Ended December 31					
	2015			2014		
Daily Production	Eagle Ford	North Dakota	Total	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	24,059	–	24,059	12,805	2,255	15,060
NGL	7,422	–	7,422	3,264	114	3,378
Total liquids (bbl/d)	31,481	–	31,481	16,069	2,369	18,438
Natural gas (mcf/d)	50,855	–	50,855	21,511	687	22,198
Total production (boe/d)	39,957	–	39,957	19,654	2,483	22,138
($ thousands except for % and per boe amounts)						
Revenue	$ 600,320	$ –	$ 600,320	$ 495,981	$ 83,274	$ 579,255
Royalties	174,102	–	174,102	146,954	27,105	174,059
Operating expenses	109,242	–	109,242	67,508	13,826	81,334
Operating netback	$ 316,976	$ –	$ 316,976	$ 281,519	$ 42,343	$ 323,862
Realized price per boe	$ 41.16	$ –	$ 41.16	$ 69.14	$ 91.88	$ 71.69
Average royalty rate	29.0%	–%	29.0%	29.6%	32.5%	30.0%
Operating expenses per boe	$ 7.49	$ –	$ 7.49	$ 9.41	$ 15.25	$ 10.07

Exploration and Evaluation Expense

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

Exploration and evaluation expense decreased to $8.8 million for the year ended December 31, 2015 from $17.7 million in 2014. The decrease for the year ended December 31, 2015 is due to lower expiries of undeveloped land in 2015.

Depletion and Depreciation

	Years Ended December 31					
	2015			2014		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[(1)]	**$ 279,744**	**$ 377,847**	**$ 661,858**	$ 328,902	$ 204,461	$ 536,569
Depletion and depreciation per boe	**$ 17.15**	**$ 25.91**	**$ 21.42**	$ 16.02	$ 25.30	$ 18.75

(1) Total includes corporate depreciation.

Depletion and depreciation expense totaled $661.9 million for the year ended December 31, 2015, as compared to $536.6 million in 2014. The increase of $115.9 million in the year ended December 31, 2015 compared to 2014 is due to increased production and a higher depletion rate. The depletion rate per boe for the year ended December 31, 2015 increased to $21.42/boe from $18.75/boe in 2014, as the Eagle Ford assets were included in the depletable base for all of 2015 and they have a higher cost base and depletion rate than assets in Canada.

Impairment

Impairment expense totaled $1,038.6 million for the year ended December 31, 2015, as compared to $449.6 million in 2014. An impairment charge of $992.9 million 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 the estimated future cash flows for our U.S. cash-generating unit below the carrying amount of the assets. The impairment included the remaining $282.9 million of goodwill associated with this acquisition along with $710.0 million related to oil and gas properties.

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$41.44/bbl in 2016, US$60.00/bbl in 2017 and US$70.00/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 discount rate of 10% before tax has been applied to the cash flows.

During the year it was determined that access to explore and develop certain lands in our Lloydminster cash-generating unit was going to be limited, as a result we recorded an impairment charge of $45.7 million on certain Canadian assets that were part of our Lloydminster cash-generating unit. The lands were subsequently disposed of in November 2015.

General and Administrative Expenses

	Years Ended December 31		
($ thousands except for per boe)	**2015**	2014	Change
General and administrative expenses	**$ 59,406**	$ 59,957	(1%)
General and administrative expenses per boe	**$ 1.92**	$ 2.10	(9%)

General and administrative ("G&A") expenses for the year ended December 31, 2015 decreased slightly to $59.4 million from $60.0 million, a decrease of $0.6 million from 2014. On a per boe basis, G&A expenses decreased 9% in 2015 from 2014. The decrease is attributable to reductions to staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending. This was offset by the acquisition of the Eagle Ford assets and associated office in Houston which contributed $11.8 million to G&A in 2015.

Acquisition-Related Costs

During the year ended December 31, 2014, we incurred acquisition-related costs for the Aurora acquisition of $38.6 million. These costs included legal, regulatory and advisory fees along with foreign currency hedge premiums. No acquisition-related costs were incurred for the year ended December 31, 2015.

Gain (Loss) on Divestiture of Oil and Gas Properties

For the year ended December 31, 2015, the Company recorded losses on non-core dispositions of oil and gas properties of $1.5 million before tax. In 2014, the Company recorded gains of $50.2 million before tax on dispositions related to the disposition of the North Dakota assets and other non-core dispositions in Canada.

Share-Based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan decreased to $15.3 million for the year ended December 31, 2015 from $27.5 million in 2014. The decrease in share-based compensation expense during 2015 is a result of the lower fair value of share awards granted combined with higher forfeitures related to a reduction in staffing levels during 2015 as compared to 2014.

Financing Costs

Financing costs include interest on bank loan and long-term notes, non-cash charges related to bank loan and long-term notes and accretion on asset retirement obligations.

	Years Ended December 31		
($ thousands except for %)	**2015**	2014	Change
Interest on bank loan	$ **14,303**	$ 21,854	(35%)
Interest on long-term notes	**89,101**	59,231	50%
Non-cash financing costs	**1,994**	1,697	18%
Accretion on asset retirement obligations	**6,262**	7,251	(14%)
Financing costs	$ **111,660**	$ 90,033	24%

Financing costs increased by $21.6 million to $111.7 million for the year ended December 31, 2015, compared to $90.0 million in 2014. Interest on long-term notes increased with increased debt levels as the Company issued US$800 million of senior unsecured notes in conjunction with the Eagle Ford acquisition in June 2014. In addition, a large portion of the Company's borrowings are in U.S. dollars which resulted in higher interest expense as the Canadian dollar weakened throughout 2015.

Foreign Exchange

Unrealized foreign exchange gains and losses are recognized with the change in the value of the long-term notes 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.

	Years Ended December 31		
($ thousands except for exchange rates)	**2015**	2014	Change
Unrealized foreign exchange loss	$ **213,999**	$ 75,011	185%
Realized foreign exchange (gain) loss	**(3,286)**	370	(988%)
Foreign exchange loss	$ **210,713**	$ 75,381	180%
CAD/USD exchange rates:			
At beginning of period	**1.1601**	1.0636	
At end of period	**1.3840**	1.1601	

The Company recorded unrealized foreign exchange loss of $214.0 million for the year ended December 31, 2015, as the liability related to its U.S. dollar denominated senior unsecured notes increased $214.0 million due to the Canadian dollar weakening against the U.S. dollar at December 31, 2015 as compared to December 31, 2014. The realized foreign exchange gain for the year ended December 31, 2015 were due to day-to-day U.S. dollar denominated transactions.

Income Taxes

	Years Ended December 31		
($ thousands)	**2015**	2014	Change
Current income tax expense	$ **8,907**	$ 53,875	$ (44,968)
Deferred income tax (recovery) expense	**(353,053)**	80,516	(433,569)
Total income tax (recovery) expense	$ **(344,146)**	$ 134,391	$ (478,537)

For the year ended December 31, 2015, current income tax expense of $8.9 million decreased by $45.0 million, as compared to $53.9 million for 2014. The decrease primarily relates to a reduction in U.S. current income taxes associated with the 2014 disposition of North Dakota assets (which contributed $52.5 million to current income taxes that year). This was offset by an increase in Canadian income taxes associated with the increased realized financial derivative gains recorded and taxed in 2015 along with Canadian operating income recorded in 2014 that was deferred to 2015 taxation.

The deferred income tax recovery of $353.1 million for the year ended December 31, 2015 increased $433.6 million from an expense of $80.5 million for 2014. The increase is primarily due to the larger net loss in the period from impairment charges and the decrease in U.S. operating income.

Tax Pools

The Company has Canadian and US tax pools, which are available to reduce future taxable income. Our cash income tax liability is dependent upon many factors, including the prices at which we sell our production, available income tax deductions and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and currently enacted tax laws in Canada and the United States, Baytex expects to receive a refund of approximately $7 million of Canadian cash income taxes during 2016.

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 is 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.

The income tax pools detailed below are deductible at various rates as prescribed by law:

($ thousands)	December 31, 2015	December 31, 2014
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 231,168**	$ 237,734
Canadian development expenditures	**347,014**	490,721
Canadian exploration expenditures	**94**	611
Undepreciated capital costs	**339,635**	428,830
Non-capital losses	**63,064**	132,522
Financing costs and other	**84,734**	76,780
Total Canadian tax pools	**$ 1,065,709**	$ 1,367,198
U.S. Tax Pools		
Depletion	**$ 383,551**	$ 354,149
Intangible drilling costs	**439,380**	311,586
Tangibles	**149,971**	209,655
Non-capital losses	**1,046,951**	553,172
Other	**65,669**	79,212
Total U.S. tax pools	**$ 2,085,522**	$ 1,507,774

Net Income (Loss) and Funds From Operations

The net loss for 2015 totaled $1,133.7 million ($5.72 per basic and diluted share) compared to net loss of $132.8 million ($0.89 per basic and diluted share) in 2014. The funds from operations for 2015 totaled $516.4 million ($2.61 per basic and diluted share) as compared to $879.8 million ($5.91 per basic and diluted share) in 2014. The components of the change in net income (loss) and funds from operations from 2014 are detailed in the following table:

	Net income (loss)	Funds from operations
Year ended December 31, 2014	**$ (132,807)**	$ 879,790
Decrease in		
Operating netback	**(546,859)**	(546,859)
Current income tax expense	**44,968**	44,968
Unrealized financial derivatives gain	**(240,016)**	–
Increase in		
Realized financial derivatives gain	**170,221**	170,221
Depletion and depreciation	**(125,289)**	–
Impairment	**(588,964)**	–
Unrealized foreign exchange loss	**(138,988)**	–
Deferred income tax (recovery)	**433,569**	–
Other[(1)(2)]	**(9,486)**	(31,703)
Year ended December 31, 2015	**$ (1,133,651)**	$ 516,417

(1) *For net income (loss), other includes exploration and evaluation expense, general and administrative expense, acquisition-related costs, share-based compensation, financing costs, realized foreign exchange loss and gain on disposition.*

(2) *For funds from operations, other includes general and administrative expenses, acquisition-related expenses, interest on bank loan and long-term notes and realized foreign exchange loss.*

Dividends

In 2015, we declared monthly dividends of $0.10 per share for January to August totaling $0.80 per share ($2.64 per share – 2014). The Company paid $96.6 million in cash dividends for the year ended December 31, 2015, and $57.3 million of dividends declared was settled by issuing 4,707,914 shares under the Company's dividend reinvestment plan. In response to the prolonged low price commodity environment, Baytex suspended the monthly dividend beginning September 2015.

Other Comprehensive Income (Loss)

Other comprehensive income (loss) is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $505.8 million foreign currency translation gain for the year ended December 31, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at December 31, 2015 compared to the exchange rate on December 31, 2014.

Capital Expenditures

Capital expenditures for the years ended December 31, 2015 and 2014 are summarized as follows:

	Years Ended December 31					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Land	$ 4,704	$ 276	$ 4,980	$ 7,250	$ 1,339	$ 8,589
Seismic	300	–	300	1,894	30	1,924
Drilling, completion and equipping	45,937	420,559	466,496	296,284	366,931	663,215
Facilities	20,309	28,954	49,263	88,800	3,543	92,343
Total exploration and development	$ 71,250	$ 449,789	$ 521,039	$ 394,228	$ 371,843	$ 766,071
Total acquisitions, net of divestitures	1,641	7	1,648	(33,863)	2,579,019	2,545,156
Total oil and natural gas expenditures	$ 72,891	$ 449,796	$ 522,687	$ 360,365	$ 2,950,862	$ 3,311,227

In response to the lower commodity prices, we reduced our capital program throughout the year with 2015 exploration and development expenditures of $521.0 million compared to $766.1 million in 2014. Capital spending was focused on our Eagle Ford assets with 86% of total capital being spent in the U.S. Spending in the U.S. totaled $449.8 million in 2015 compared to $371.8 million in 2014 and we drilled 50.2 net wells in 2015 compared to 33.2 net wells in 2014. 2014 exploration and development expenditures included Eagle Ford development from the acquisition date in June of 2014 and included $56.2 million of expenditures on the North Dakota assets. In 2015, we worked with our partner in the Eagle Ford to achieve significant cost savings. Drilling, completions and equipping costs per well have decreased from approximately US$8.5 million in 2014 to approximately US$6.2 million in 2015. The weakening of the Canadian dollar offset some of the cost savings achieved.

Activity in Canada was significantly reduced in 2015 as we drilled 31.4 net wells and spent $71.3 million compared to 175.1 net wells and $394.2 million in 2014. Despite achieving cost reductions of approximately 20% in Canada, the commodity prices did not support drilling in Peace River or Lloydminster in the second half of 2015 which resulted in significantly less expenditures for the year.

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 by approximately 40% from our initial plans and working with our lending syndicate to relax certain financial covenants related to our credit facilities on February 19, 2015 and again on December 8, 2015. On April 2, 2015, we closed an equity financing and 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.

At December 31, 2015, net debt was $2,049.9 million, as compared to $2,296.0 million at December 31, 2014. The decrease at December 31, 2015 is primarily attributable to the equity proceeds of $606.0 million being applied to outstanding bank debt. This was partially offset by the increase in our U.S. dollar denominated bank loan and long-term notes of $240.4 million due to the weakening Canadian dollar and a $114.4 million increase in credit facilities as dividend payments and capital expenditures exceeded funds from operations.

Bank Loan

Baytex has revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a $50 million operation loan, a $750 million syndicated loan and a US$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants as detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension 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). 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 and January 7, 2016).

The weighted average interest rate on the credit facilities for the year ended December 31, 2015 was 3.32% (year ended December 31, 2014 – 3.25%).

Long-Term Notes

Baytex has five series of senior unsecured notes outstanding that total $1.62 billion as at December 31, 2015. The senior unsecured notes do not contain any significant financial maintenance covenants. The notes contain a minimum fixed charge coverage ratio covenant as a debt incurrence covenant which, if not met, limits the Company from taking on new borrowings beyond existing senior unsecured notes and credit facilities.

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.

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

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "2021 Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "2024 Notes"). The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at 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.

Covenants

The following table lists the covenants under the Revolving Facilities and the senior unsecured notes, and the compliance therewith as at December 31, 2015.

Covenant Description		Position as at December 31, 2015
Revolving Facilities – Financial Covenants	**Maximum Ratio**	
Senior debt to Capitalization(1)(2)	0.65:1.00	0.44:1.00
Senior debt to Bank EBITDA(1)(5)	5.25:1.00	2.97:1.00
Total debt to Bank EBITDA(3)(5)	5.25:1.00	2.97:1.00
Senior Unsecured Notes – Debt Incurrence Covenant	**Minimum Ratio**	
Fixed charge coverage(4)	2:50:1.00	5.63:1.00

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

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

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

(4) Fixed charge coverage is computed as the ratio of financing costs excluding accretion on asset retirement obligations to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended December 31, 2015 was $629 million.

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

On December 8, 2015, we reached an agreement with the lending syndicate to amend the financial covenants as follows: a) the maximum Senior Debt to capitalization ratio will be 0.65:1.00 for the period December 31, 2015 up to and including December 31, 2017, and 0.55:1.00 thereafter; b) the maximum Senior Debt to Bank EBITDA ratio will be 5.25:1.00 for the period December 31, 2015 up to and including December 31, 2017, and 3.50:1.00 thereafter; and c) the maximum Total Debt to Bank EBITDA will be 5.25:1.00 for the period December 31, 2015 up to and including December 31, 2017, 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 the Company will encounter difficulty in meeting obligations associated with financial liabilities. We manage liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default, resulting in the Company incurring a loss. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is partially mitigated through a series of derivative contracts intended to reduce some of the volatility of our funds from operations.

A summary of the risk management contracts in place as at December 31, 2015 and the accounting treatment thereof is disclosed in note 19 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 February 28, 2016, we had 210,688,856 common shares and no preferred shares issued and outstanding. During the year ended December 31, 2015, shares were issued through an equity financing, the dividend reinvestment plan 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 December 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	$ 267,838	$ 267,838	$ –	$ –	$ –
Bank loan[1][2]	256,749	–	–	256,749	–
Long-term notes[2]	1,623,658	–	–	8,858	1,614,800
Interest on long-term notes	620,144	94,064	188,129	186,969	150,982
Operating leases	50,305	8,063	16,501	15,589	10,152
Processing agreements	52,147	9,219	10,340	9,043	23,545
Transportation agreements	75,392	13,910	24,556	23,371	13,555
Total	$ 2,946,233	$ 393,094	$239,526	$ 500,579	$1,813,034

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

(2) Principal amount of instruments.

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 December 31, 2015, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 3 and 4 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with GAAP requires management to make judgments and estimates that affect the financial results of the Company. The financial and operating results of Baytex incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated future recoverable value of petroleum and natural gas properties;
- estimated depletion and depreciation that are based on estimates of petroleum and natural gas reserves and future costs to develop those reserves that Baytex expects to recover in the future;
- estimated fair value of oil and gas properties and exploration and evaluation assets from business combinations;
- estimated fair value of financial derivative contracts that are subject to fluctuation depending upon the underlying commodity prices, interest rates and foreign exchange rates;
- estimated value of share-based compensation related to our Share Award Incentive Plan and related performance conditions and forfeiture rates; and
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures.

Baytex employs individuals skilled in making such estimates and ensures those responsible have the most accurate information available. Further, approved budgets and prior period estimates are also reviewed and analyzed against actual results to ensure appropriate decisions are made for future estimates and outlooks. Actual results could differ materially if various assumptions or estimates do not turn out as expected.

CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Revenue from Contracts with Customers

International Financial Reporting Standards ("IFRS") 15 "Revenue from Contracts with Customers" is effective January 1, 2018 and will supersede IAS 11 "Construction Contracts" and IAS 18 "Revenue" and related interpretations. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The new standard also requires disclosures on the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The Company has not yet adopted IFRS 15 and is evaluating its impact on the consolidated financial statements.

Financial Instruments

IFRS 9 "Financial Instruments" replaces IAS 39 "Financial Instruments: Recognition and Measurement", which eliminates the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. In November 2013, the IASB amended IFRS 9 to include the new general hedge accounting model which remains optional, allows more opportunities to apply hedge accounting, and will be effective on January 1, 2018 and applied retroactively to each period presented. The Company has not yet adopted IFRS 9 and is evaluating its impact on the consolidated financial statements.

Leases

IFRS 16 "Leases" replaces IAS 17 "Leases" and is effective January 1, 2019 with early adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers". The new standard will bring most leases on-balance sheet for lessees. The Company has not yet adopted IFRS 16 and is evaluating its impact on the consolidated financial statements.

2016 GUIDANCE

As an industry, we continue to face unprecedented challenges due to the continued global oversupply of crude oil. We are committed to preserving financial liquidity through this downturn. In 2016, we are targeting capital expenditures to approximate funds from operations in order to minimize additional bank borrowings. In addition, we may contemplate minor non-core asset sales.

Our original 2016 production guidance was 74,000 to 78,000 boe/d with budgeted exploration and development expenditures of $325 to $400 million. This budget contemplated ramping up activity in Canada in the second half of 2016.

Based on the forward strip for the remainder of 2016, we do not plan to execute our heavy oil development program this year. We will forgo drilling 12 net wells at Peace River and 24 net wells at Lloydminster. In addition, we are proactively shutting-in approximately 7,500 bbl/d of low or negative margin heavy oil production in order to optimize the value of our resource base and maximize our funds from operations. Should netbacks improve, we have the ability to restart these wells within one month. We currently anticipate that this production will be brought back on-line mid-year.

In the Eagle Ford, we now anticipate a reduced pace of development in 2016 with approximately four to five drilling rigs (six drilling rigs in fourth quarter of 2015) and one to two frac crews (two frac crews in the fourth quarter of 2015) working on our lands. At this pace, we anticipate bringing approximately 30 net wells on production in 2016 (previously 35 to 40 net wells).

We now anticipate 2016 exploration and development expenditures of $225 to $265 million, of which approximately 95% will be invested in the Eagle Ford. At the mid-point, this reflects a 33% reduction in capital spending for 2016 relative to our initial expectation of $325 to $400 million and a 53% reduction relative to 2015 capital expenditures of $521 million. Our 2016 program will remain flexible and allows for adjustments to spending based on changes in the commodity price environment.

Taking into account the shut-in heavy oil volumes and a reduced capital program, we have revised our production guidance range for 2016 to 68,000 to 72,000 boe/d. Our revised production guidance represents an approximate 5% reduction to our original guidance, excluding the impact of shut-in volumes. This compares to a 33% reduction in our capital budget, demonstrating the continued strong performance of our assets. Based on the mid-point of our production guidance range, approximately 55% of our production is expected to be generated in the Eagle Ford with the remaining 45% coming from our Canadian assets.

Production during the first quarter of 2016 is expected to average 73,000 to 75,000 boe/d.

SELECTED ANNUAL INFORMATION

($ thousands, except per common share amounts)	2015	2014
Revenues, net of royalties	$ 888,447	$ 1,529,897
Net income (loss)	$ (1,133,651)	$ (132,807)
Per common share – basic	$ (5.72)	$ (0.89)
Per common share – diluted	$ (5.72)	$ (0.89)
Total assets	$ 5,488,498	$ 6,230,596
Total bank loan and long-term notes	$ 1,854,929	$ 2,062,344
Cash dividends or distributions declared per common share	$ 0.80	$ 2.64
Average wellhead prices, net of blending costs ($/boe)	$ 35.40	$ 66.54
Total production (boe/d)	84,648	78,395

QUARTERLY FINANCIAL INFORMATION

($ thousands, except per common share amounts)	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Gross revenues	**230,200**	268,625	345,432	285,615	472,394	634,415	476,404	385,809
Net income (loss)	**(412,924)**	(517,856)	(26,955)	(175,916)	(361,816)	144,369	36,799	47,841
Per common share – basic	**(1.96)**	(2.49)	(0.13)	(1.04)	(2.16)	0.87	0.27	0.38
Per common share – diluted	**(1.96)**	(2.49)	(0.13)	(1.04)	(2.16)	0.86	0.27	0.38

FOURTH QUARTER OF 2015

Our production for the three months ended December 31, 2015 was 81,110 boe/d, a decrease of 11,161 boe/d as compared to 92,271 boe/d for the fourth quarter of 2014. The declines are due to reduced capital spending, non-core dispositions and uneconomic production we have shut-in. The price of WTI decreased by US$30.96/bbl, or 42%, to US$42.18/bbl in the fourth quarter of 2015 compared to the same period in 2014. Funds from operations were $93.1 million, bringing total funds from operations for the year to $516.4 million. Net loss of $410.0 million in the fourth quarter of 2015 increased from a net loss of $361.8 million for the same period in 2014 due to lower operating netbacks and a larger impairment in the current period.

	Three Months Ended December 31	
	2015	2014
Benchmark Averages		
WTI oil (US$/bbl)	**42.18**	73.14
WCS heavy (US$/bbl)	**27.69**	58.90
Heavy oil differential	**35%**	20%
CAD/USD exchange rate	**1.3353**	1.1378
Edmonton par oil ($/bbl)	**52.94**	75.69
LLS (US$/bbl)	**43.33**	76.34
AECO gas price ($/mcf)	**2.65**	4.01
NYMEX gas price (US$/mmbtu)	**2.27**	4.00

	Three Months Ended December 31					
	2015			2014		
($ thousands, except as noted)	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production						
Heavy oil (bbl/d)	31,733	–	31,733	43,186	–	43,186
Light oil and condensate (bbl/d)	1,600	23,330	24,930	2,494	24,422	26,916
NGL (bbl/d)	973	8,023	8,996	1,381	6,717	8,098
Natural gas (mcf/d)	39,122	53,586	92,708	43,048	41,380	84,428
Total production (boe/d)	40,826	40,284	81,110	54,236	38,035	92,271
Baytex Average Sales Prices						
Canadian heavy oil ($/bbl)(1)	$ 24.41	$ –	$ 24.41	$ 53.34	$ –	$ 53.34
Light oil and condensate ($/bbl)	47.84	50.33	50.17	70.77	77.86	77.20
NGL ($/bbl)	19.93	16.90	17.23	33.31	26.99	28.07
Natural gas ($/mcf)	2.36	3.05	2.76	3.89	4.36	4.12
Weighted average ($/boe)(2)	$ 23.59	$ 36.56	$ 30.03	$ 49.66	$ 59.50	$ 53.72
Operating netback ($/boe)						
Oil and natural gas revenues	$ 23.59	$ 36.56	$ 30.03	$ 49.66	$ 59.50	$ 53.72
Other income	–	–	0.11	–	–	0.76
Less:						
Royalties	2.72	10.56	6.61	7.94	17.56	11.90
Operating expenses	12.27	7.23	9.76	14.76	10.36	12.95
Transportation expenses	2.87	–	1.45	3.51	–	2.07
Operating netback	$ 5.73	$ 18.77	$ 12.32	$ 23.45	$ 31.58	$ 27.56
Financial derivatives gain	–	–	4.09	–	–	6.48
Operating netback after financial derivatives	$ 5.73	$ 18.77	$ 16.41	$ 23.45	$ 31.58	$ 34.04
Capital Expenditures						
Exploration and development	$ 8,804	$ 131,992	$ 140,796	$ 65,234	$ 149,463	$ 214,697
Acquisitions, net of divestitures	$ (593)	$ 19	$ (574)	$ (42,212)	$ 6,546	$ (35,666)

(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.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2015 with the same period in 2014:

- Total production for the fourth quarter of 2015 of 81,110 boe/d decreased by 12%, or 11,161 boe/d, from the same period in 2014, with 3,900 boe/d associated with declines from non-core dispositions and uneconomic production we have shut-in.
- FFO for the fourth quarter of 2015 was $93.1 million ($0.44 per basic share), a 62% decrease from $245.5 million ($1.47 per basic share) in the fourth quarter of 2014.
- WTI oil averaged US$42.18/bbl for the fourth quarter of 2015, a 42% decrease from the average WTI price of US$73.14/bbl in the fourth quarter of 2014.
- Our average realized heavy oil price during the fourth quarter of 2015 was $24.41/bbl, or 66% of WCS, compared to $53.34/bbl, or 80% of WCS, in the fourth quarter of 2014. This decrease was due to a lower WTI price partially offset the weakening of the Canadian dollar compared to the fourth quarter of 2014.
- Total petroleum and natural gas revenues for the fourth quarter of 2015 were $230.2 million, a decrease of $242.2 million from the same period in 2014. Canadian revenues totaled $93.9 million, a decrease of $163.9 million from the fourth quarter of 2014 due to lower crude oil prices. In the U.S., the Eagle Ford properties contributed $135.5 million of revenue for the three months ended December 31, 2015, a decrease of $72.7 million from the same period in 2014.
- Operating expenses for the fourth quarter of 2015 of $72.9 million decreased $37.0 million compared to the same period in 2014 primarily due to lower production volumes associated with our Canadian assets combined with cost reductions achieved across all operations. Operating expenses per boe decreased by $3.19/boe from the fourth quarter of 2014 to $9.76/boe in the current period due to cost savings initiatives.
- General and administrative expenses for the three months ended December 31, 2015 were $12.8 million, a decrease of $4.2 million from the same period in 2014 due to reductions to staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending. On a per boe basis, general and administrative expenses decreased by $0.28/boe from the fourth quarter of 2014 to $1.72/boe due to cost controls and the low incremental overhead associated with the acquired Eagle Ford assets.
- Financing costs for the fourth quarter of 2015 of $27.9 million increased $0.6 million as compared to the same period in 2014 due to higher interest expense on U.S. dollar denominated debt as the Canadian dollar weakened against the U.S. dollar offset by lower borrowings on the credit facilities.
- Realized gains on financial derivative contracts totaled $30.5 million for the three months ended December 31, 2015, a decrease of $24.5 million from the same period in 2014 mainly due to higher oil volumes hedged in 2014 as both periods saw a significant drop in WTI prices to levels below those set in our fixed price contracts.
- Unrealized gains on financial derivative contracts totaled $37.9 million for the fourth quarter, a decrease of $91.5 million from the same period in 2014 due to larger decline in prices during the fourth quarter of 2014 and higher oil volumes hedged.
- Depletion expense totaled $163.8 million for the three months ended December 31, 2015, as compared to $176.4 million in the same period of 2014 due to declining production volumes. The depletion rate per boe for the fourth quarter of 2015 remained consistent at $21.12/boe compared to $20.78/boe for the same period in 2014.
- Due to the further decline in commodity prices, we have recorded a $545.3 million impairment charge in the fourth quarter of 2015 as compared to the $449.6 million in the same period in 2014. The impairment relates to $499.6 million of oil and gas properties associated with the Eagle Ford acquisition and $45.7 million of impairment recognized prior to the disposition of non-core assets in Canada.
- Capital expenditures related to exploration and development of $140.8 million were incurred in the fourth quarter of 2015, a decrease of $73.9 million from the same period in 2014. The decrease was mainly in response to the drop in commodity prices during 2015 compared to 2014. We drilled 12.6 net wells in the fourth quarter of 2015 (all in the Eagle Ford), compared to 28.3 net wells (12.9 in Canada and 15.4 in Eagle Ford) during the same period in 2014.

RISK FACTORS

Baytex management is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with our business that can impact the financial results. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2015 under the "Risk Factors" section.

Volatility of Oil and Natural Gas Prices

Our financial condition is substantially dependent on, and highly sensitive to the prevailing prices of crude oil and natural gas. Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, it could also result in the shut in of currently producing wells, a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

Our reserves as at December 31, 2015 are estimated using forecast prices and costs. These prices are above current crude oil and natural gas prices. If crude oil and natural gas prices stay at current levels, our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

We conduct assessments of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas forecast prices decline further, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

Debt Service and Refinancing

We are required to comply with covenants under the Revolving Facilities and the our senior unsecured notes. In the event that we do not comply with these covenants, our access to capital (including our ability to make borrowings under our Revolving Facilities) could be restricted or repayment could be required on an accelerated basis by our lenders.

Our existing Revolving Facilities and any replacement facilities may not provide sufficient liquidity. We currently have Revolving Facilities in the amount of $800 million plus US$200 million. The amounts available under our existing Revolving Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. There can be no assurance that the amount of our Revolving Facilities will be adequate for our future financial obligations, including our future capital expenditure program, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations. In the event that the Revolving Facilities are not extended before June 2019, indebtedness under the Revolving Facilities will be repayable at that time. There is also a risk that the Revolving Facilities will not be renewed for the same amount or on the same terms.

Access to Capital Markets

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future shareholders.

Our ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in our securities in particular and our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

Non-operating Agreements in the U.S.

Marathon Oil EF LLC ("Marathon Oil"), a wholly-owned subsidiary of Marathon Oil Corporation, is the operator of a substantial majority of our Eagle Ford acreage and we will be reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interests and the collective best interests of all of the working interest owners of this acreage, which may not be in our best interests. We have a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of drilling locations and schedules. The success and timing of development activities operated by Marathon Oil will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- Marathon Oil's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. If we are not willing or are unable to fund our capital expenditure requirements relating to our Marathon Oil-operated drilling locations, our interests in our drilling locations may be diluted or forfeited.

Variations in Interest Rates and Foreign Exchange Rates

There is a risk that the interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease to the market price of our common shares.

World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our revenues. A substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as a large portion of our senior unsecured notes are denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

Credit Risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flows and financial position.

Hedging Program

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. We also use derivative instruments in various operational markets to optimize our supply or production chain. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and may also result in royalties being paid on a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves.

Additional Business Risks

Our business involves many operating risks related to acquiring, developing and exploring for oil and natural gas which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation and interruptions; reservoir performance and technical challenges; partner risks; competition; technology; land claims; our ability to hire and retain necessary skilled personnel; the availability of drilling and related equipment; information systems; seasonality and access restrictions; timing and success of integrating the business and operations of acquired assets and companies; phased growth execution; risk of litigation, regulatory issues, increases in government taxes and changes to royalty or mineral/severance tax regimes; and risk to our reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of federal, provincial and state legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Although Baytex believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on Baytex's business, financial condition, results of operations and prospects.

Climate Change Regulation

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation that is enacted in jurisdictions where we have operations. A number of federal, provincial and state governments have announced their intention to regulate greenhouse gases and certain air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. In most cases there are few technical details regarding the implementation and coordination of these plans. The Canadian federal government has stated that it will work with the provinces of Canada to come up with a national strategy and it remains unclear what approach the United States federal government will take. Currently, certain provinces and states, including Alberta and British Columbia, have implemented greenhouse gas emission legislation that impacts areas in which we operate and Alberta has announced a new climate change policy which is expected to include a carbon tax. It is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

Further information regarding environmental and climate change regulation is contained in our Annual Information Form for the year ended December 31, 2015 under the "Industry Conditions – Climate Change Regulation" section.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2015, an evaluation was conducted of the effectiveness of Baytex's "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that Baytex's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that Baytex files or submits under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that Baytex's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

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; our ability to reduced our fixed operating costs; our expectation that we will receive a refund of Canadian cash income taxes during 2016 and the amount thereof; the proposed reassessment of our tax filings by the Canada Revenue Agency; the potential taxes owing and reduction of non-capital losses if the reassessment by the Canada Revenue Agency is successful; our intention to defend the proposed reassessments if issued by the Canada Revenue Agency; our view of our tax filing position; 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; the impact of the adoption of new accounting standards on our financial results; our target for 2016 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings; the possibility of non-core asset sales; our expectations for annual average production rate and exploration and development capital budget for 2016 (both original and revised); our expectation that we will not proceed with our 2016 heavy oil development program; the number of drilling rigs and frac crews working on our Eagle Ford lands during 2016; the portion of our 2016 capital budget to be invested in the Eagle Ford; the number of net wells to be brought on production in the Eagle Ford during 2016; the geographic breakdown of our 2016 annual production; our expectations for the average production rate in Q1/2016; and our expectation that we are in material compliance with environmental legislation. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices; further declines or an extended period of the currently low oil and natural gas prices; failure to comply with the covenants in our debt agreements; refinancing risk for existing debt and debt service costs; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; a downgrade of our credit ratings; risks associated with properties operated by third parties; 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 risks; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; 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 changes in market-based factors and the discretionary nature of dividend payments; 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, 2015, 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2015, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015 has been audited by Deloitte LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2015.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Baytex Energy Corp. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of Deloitte LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

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

Rodney D. Gray
Chief Financial Officer
Baytex Energy Corp.

March 2, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Baytex Energy Corp.:

We have audited the accompanying consolidated financial statements of Baytex Energy Corp. and subsidiaries (the "Company"), which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014, and the consolidated statements of income (loss) and comprehensive income (loss), consolidated statements of changes in equity, and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as Management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by Management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Baytex Energy Corp. and subsidiaries as at December 31, 2015 and December 31, 2014, and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants

March 2, 2016
Calgary, Canada

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Baytex Energy Corp.:

We have audited the internal control over financial reporting of Baytex Energy Corp. and subsidiaries (the "Company") as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as at and for the year ended December 31, 2015 of the Company and our report dated March 2, 2016 expressed an unmodified/unqualified opinion on those consolidated financial statements.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants

March 2, 2016
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	December 31, 2015	December 31, 2014
(thousands of Canadian dollars)		
ASSETS		
Current assets		
Cash	$ 247	$ 1,142
Trade and other receivables	98,093	203,521
Financial derivatives (note 19)	106,573	220,146
	204,913	424,809
Non-current assets		
Financial derivatives (note 19)	4,417	498
Exploration and evaluation assets (note 7)	578,969	542,040
Oil and gas properties (note 8)	4,674,175	4,983,916
Other plant and equipment (note 9)	26,024	34,268
Goodwill (note 10)	–	245,065
	$ 5,488,498	$ 6,230,596
LIABILITIES		
Current liabilities		
Trade and other payables	$ 267,838	$ 398,261
Dividends payable to shareholders	–	16,811
Financial derivatives (note 19)	–	54,839
	267,838	469,911
Non-current liabilities		
Bank loan (note 11)	252,172	663,312
Long-term notes (note 12)	1,602,757	1,399,032
Asset retirement obligations (note 13)	296,002	286,032
Deferred income tax liability (note 17)	655,255	905,532
	3,074,024	3,723,819
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 14)	4,296,831	3,580,825
Contributed surplus	4,575	31,067
Accumulated other comprehensive income	705,382	199,575
Deficit	(2,592,314)	(1,304,690)
	2,414,474	2,506,777
	$ 5,488,498	$ 6,230,596

Commitments and contingencies (note 21)

See accompanying notes to the consolidated financial statements.

Naveen Dargan
Director, Baytex Energy Corp.

Gregory K. Melchin
Director, Baytex Energy Corp.

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

Years Ended December 31	2015	2014
(thousands of Canadian dollars, except per common share amounts)		
Revenue, net of royalties		
Petroleum and natural gas sales	$ 1,129,872	$ 1,969,022
Royalties	(241,425)	(439,125)
	888,447	1,529,897
Expenses		
Operating	320,187	353,849
Transportation	53,127	83,766
Blending	27,830	58,120
Exploration and evaluation (note 7)	8,775	17,743
Depletion and depreciation (note 8 and 9)	661,858	536,569
Impairment (notes 8 and 10)	1,038,554	449,590
General and administrative	59,406	59,957
Acquisition-related	–	38,591
Share-based compensation (note 15)	15,344	27,463
Financing (note 18)	111,660	90,033
Financial derivatives (gain) (note 19)	(142,729)	(212,524)
Foreign exchange loss (note 20)	210,713	75,381
Loss (gain) on disposition of oil and gas properties	1,519	(50,225)
	2,366,244	1,528,313
Net income (loss) before income taxes	(1,477,797)	1,584
Income tax expense (recovery) (note 17)		
Current income tax expense	8,907	53,875
Deferred income tax (recovery) expense	(353,053)	80,516
	(344,146)	134,391
Net income (loss) attributable to shareholders	$(1,133,651)	$ (132,807)
Other comprehensive income		
Foreign currency translation adjustment	505,807	213,533
Comprehensive income (loss)	$ (627,844)	$ 80,726
Net income (loss) per common share (note 16)		
Basic	$ (5.72)	$ (0.89)
Diluted	$ (5.72)	$ (0.89)
Weighted average common shares (note 16)		
Basic	198,207	148,932
Diluted	198,207	148,932

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars)	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	**Total equity**
Balance at December 31, 2013	$ 2,004,203	$ 53,081	$ 1,484	$ (776,283)	**$ 1,282,485**
Dividends to shareholders	–	–	–	(395,600)	**(395,600)**
Exercise of share rights	25,667	(14,369)	–	–	**11,298**
Vesting of share awards	35,108	(35,108)	–	–	**–**
Share-based compensation	–	27,463	–	–	**27,463**
Issued for cash	1,495,044	–	–	–	**1,495,044**
Issuance costs, net of tax	(78,468)	–	–	–	**(78,468)**
Issued pursuant to dividend reinvestment plan	99,271	–	–	–	**99,271**
Accumulated other comprehensive income recognized on disposition of foreign operation	–	–	(15,442)	–	**(15,442)**
Comprehensive income for the year	–	–	213,533	(132,807)	**80,726**
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	41,836	(41,836)	–	–	**–**
Share-based compensation	–	15,344	–	–	**15,344**
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 year	–	–	505,807	(1,133,651)	**(627,844)**
Balance at December 31, 2015	$ 4,296,831	$ 4,575	$ 705,382	$ (2,592,314)	**$ 2,414,474**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31	2015	2014
(thousands of Canadian dollars)		
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income (loss) for the year	$(1,133,651)	$ (132,807)
Adjustments for:		
Share-based compensation (note 15)	15,344	27,463
Unrealized foreign exchange loss (note 20)	213,999	75,011
Exploration and evaluation (note 7)	8,775	17,743
Depletion and depreciation (note 8)	661,858	536,569
Impairment (notes 8 and 10)	1,038,554	449,590
Non-cash financing costs	8,256	8,948
Unrealized financial derivatives (gain) loss (note 19)	54,816	(185,200)
(Gain) loss on disposition of oil and gas properties	1,519	(50,225)
Current income tax expense on dispositions	–	52,182
Deferred income tax (recovery) expense	(353,053)	80,516
Change in non-cash working capital (note 20)	43,891	31,890
Asset retirement obligations settled (note 13)	(10,888)	(14,528)
	549,420	897,152
Financing activities		
Payment of dividends	(109,806)	(307,103)
(Decrease) increase in bank loan	(439,465)	287,986
Net proceeds from issuance of long-term notes	–	849,944
Tenders of long-term notes	(10,372)	(793,099)
Issuance of common shares related to share rights (note 14)	–	11,298
Issuance of common shares, net of issuance costs (note 14)	606,095	1,401,317
	46,452	1,450,343
Investing activities		
Additions to exploration and evaluation assets (note 7)	(5,642)	(15,824)
Additions to oil and gas properties (note 8)	(515,397)	(750,247)
Property acquisitions	(2,070)	(15,335)
Corporate acquisition (note 6)	–	(1,866,307)
Proceeds from disposition of oil and gas properties	423	383,130
Current income tax expense on dispositions	(8,181)	(42,894)
Additions to other plant and equipment, net of disposals	4,107	(8,283)
Change in non-cash working capital (note 20)	(70,968)	(50,416)
	(597,728)	(2,366,176)
Impact of foreign currency translation on cash balances	961	1,455
Change in cash	(895)	(17,226)
Cash, beginning of year	1,142	18,368
Cash, end of year	$ 247	$ 1,142
Supplementary information		
Interest paid	$ 100,257	$ 77,417
Income taxes paid	$ 12,064	$ 44,587

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2015 AND 2014
(all tabular amounts in thousands of Canadian dollars, except per common share amounts)

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 ("TSX") 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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. The significant accounting policies set out below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex on March 2, 2016.

The consolidated financial statements have been prepared on the historical cost basis, with some exceptions as noted in the accounting policies set out below. 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. On the consolidated statement of cash flows, financing costs have been reclassified from financing activities to operating activities for the year ended December 31, 2014. This resulted in a decrease to cash flows from operating activities resulting in a $77.4 million decrease to cash flow from operations and a corresponding increase to cash flow from financing activities.

Measurement Uncertainty and Judgments

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Accordingly, actual results can differ from those estimates. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, expenses, and disclosure of contingencies are discussed below.

Oil and Gas Activities

Reserves estimates can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion, asset retirement obligations, asset impairments and business combinations. The estimation of reserves is a complex process requiring significant judgment. The Company's reserves are estimated annually using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent or greater statistical probability of being recovered (total proved plus probable reserves) or a 25 percent or greater statistical probability of being recovered (total possible reserves). Changes to estimates such as forward price estimates, production costs, recovery rates and accordingly, economic status of reserves may have a material impact on the consolidated financial statements.

The Company's capital assets are aggregated into cash-generating units based on management's judgment of their ability to generate largely independent cash flows. The cash-generating units are used to assess impairment and accordingly, can directly impact the recoverability of the assets therein. Impairment of assets and groups of assets are calculated based on the higher of value-in-use calculations and fair value less cost to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, royalty rates, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and natural gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. The Company assesses internal and external indicators of impairment in determining whether the carrying values of the assets may not be recoverable.

The determination of technical feasibility and commercial viability of exploration and evaluation ("E&E") assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment.

Depletion and Depreciation

The amounts recorded for depletion of oil and gas properties are based on a unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. See Oil and Gas Activities above for discussion of estimates and judgments involved in reserve estimation.

Amounts recorded for depreciation are based on the estimated useful lives of depreciable assets; management reviews these estimates at each reporting date.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and exploration and evaluation assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net income (loss) can be affected as a result of changes in future depletion, depreciation, asset impairment or goodwill impairment.

Joint Control

Judgment is required to determine when the Company has joint control over a joint operation, which requires an assessment of the capital and operating activities of the projects undertaken with partners and when decisions in relation to those activities require unanimous consent.

Fair Value Measurement

Fair values of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs and are described in note 19. These estimates may vary from the actual prices achieved upon settlement of the financial instruments.

Share-based Compensation

Compensation expense related to the Company's performance awards under the Share Award Incentive Plan is dependent on estimated fair values, forfeiture rates, and for performance awards, a payout multiplier based on past performance. Compensation expense may fluctuate due to changes in management's estimates.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations are based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future and the discount and inflation rates. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Legal

The Company is engaged in litigation and claims arising in the normal course of operations where the actual outcome may vary from the amount recognized in the consolidated financial statements. None of these claims are expected to materially affect the Company's financial position or reported results of operations.

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and differing interpretations require management judgment. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards may result in a material change in the Company's provision for income taxes. As such, income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Partnership. Intercompany balances, net income (loss) and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

A portion of the Company's exploration, development and production activities is conducted through jointly controlled operations. The financial statements reflect the Company's proportionate interest where the Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases. Joint control exists for contractual arrangements governing assets whereby the Company has less than 100 per cent working interest, all of the partners have control of the arrangement collectively, and spending on the project requires unanimous consent of all parties that collectively control the arrangement and share the associated risks.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The cost of an acquisition is measured as cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed, including contingent liabilities, are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the deficiency is credited to net income (loss) in the statements of income (loss) and comprehensive income (loss) in the period of acquisition. Associated transaction costs are expensed when incurred.

Exploration and Evaluation Assets, Oil and Gas Properties and Other Plant and Equipment

Pre-license Costs

Pre-license costs are costs incurred before the legal rights to explore a specific area have been obtained. These costs are expensed in the period in which they are incurred.

E&E Costs

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well program/project is complete and the results have been evaluated.

Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing. E&E costs are capitalized until technical feasibility and commercial viability of extracting petroleum and natural gas resources is considered to be determined. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. All such costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract value from the asset. If the asset is determined not to be technically feasible or economically viable, an impairment is charged to exploration and evaluation expense. Upon determination of technical feasibility and commercial viability, the E&E assets attributable to those reserves are first tested for impairment and then reclassified to oil and gas properties.

Borrowing Costs and Other Capitalized Costs

Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset form part of the cost of that asset. A qualifying asset is an asset that requires a period of one year or greater to get ready for its intended use or sale. Baytex currently has no qualifying assets that would allow for borrowing costs to be capitalized to the asset and all borrowing costs are expensed as incurred.

Depletion and Depreciation

The net carrying value of oil and gas properties is depleted using the unit-of-production method based on estimated proved and probable reserves. Future development costs, which are the estimated costs necessary to bring those reserves into production, are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil.

The depreciation methods and estimated useful lives for other plant and equipment are as follows:

Classification	Method	Rate or period
Motor Vehicles	Diminishing balance	15%
Office Equipment	Diminishing balance	20%
Computer Hardware	Diminishing balance	30%
Furniture and Fixtures	Diminishing balance	10%
Leasehold Improvements	Straight-line over life of the lease	Various
Other Assets	Diminishing balance	Various

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively.

Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net identifiable assets acquired, which is inherently imprecise as estimates and judgment are required in the determination of the fair value of assets and liabilities. The portion of goodwill related to U.S. operations had fluctuated due to changes in foreign exchange rates subsequent to the date of acquisition. Goodwill is assessed for impairment at least annually at year end, or more frequently if events or changes in circumstances indicate that the asset may be impaired. Impairment is recognized in net income (loss) and is not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal. Goodwill is not deductible for income tax purposes.

Impairment of Non-financial Assets

E&E assets are assessed for impairment when they are reclassified to oil and gas properties and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The Company assesses other assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable.

Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets (the "cash-generating unit" or "CGU"). Goodwill acquired is allocated to CGUs expected to benefit from synergies of the related business combination.

The Company assesses its CGUs for impairment when indicators of impairment exist or at least annually for CGUs with goodwill. The Company compares the recoverable amount of the CGU to its carrying amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value-in-use. In assessing the recoverable amount, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces first the carrying amount of any goodwill allocated to the CGU. Any remaining impairment is allocated to the individual assets in the CGU on a pro-rata basis. Impairment is charged to net income (loss) in the period in which it occurs.

For all assets (other than goodwill), an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized for the asset in prior years and circumstances indicate the impairment no longer exists. Such reversal is recognized in net income (loss). Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Asset Retirement Obligations

The Company recognizes a liability for the future asset retirement costs associated with its oil and gas properties discounted using the risk free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted to expense over its useful life. The liability is accreted until the date of expected settlement of the retirement obligations and is recognized within financing costs in the statements of income (loss) and comprehensive income (loss). Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows on the discount rates are recognized as changes in the asset retirement obligation provision and related asset.

Foreign Currency Translation

Foreign transactions

Transactions completed in currencies other than the functional currency are reflected in Canadian dollars at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to Canadian dollars at the period-end exchange rate. Revenue and expenses are translated to Canadian dollars using the average exchange rate for the period. Both realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income (loss).

Foreign operations

As several of the Company's subsidiaries operate and transact primarily in countries other than Canada, they accordingly have functional currencies other than the Canadian dollar. The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Assets and liabilities of foreign operations are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. The resulting unrealized gains or losses are included in accumulated other comprehensive income in shareholders' equity and are reclassified to net income (loss) when there has been a disposal or partial disposal of the foreign operation.

Revenue Recognition

Revenue associated with sales of petroleum and natural gas is recognized when title passes to the purchaser at the delivery point and collectability of the revenue is probable. Revenue from the production of petroleum and natural gas in which the Company has an interest with other producers is recognized based on the Company's working interest and the terms of the relevant agreements. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty with the right and intent to settle net are recorded on a net basis.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: fair value through profit or loss ("FVTPL"), loans and receivables, held-to-maturity investments, available-for-sale financial assets and other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets are measured at fair value and changes in fair value are recognized in net income (loss). Available-for-sale financial assets are measured at fair value with changes in fair value recorded in other comprehensive income (loss) until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest method. Cash and financial derivatives are classified at FVTPL. Trade and other receivables are classified as loans and receivables, which are measured at amortized cost. Trade and other payables, dividends payable to shareholders, bank loan and long-term notes are classified as other financial liabilities, which are measured at amortized cost.

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts consist of a host contract and an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The embedded derivatives are measured at FVTPL.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed immediately. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income (loss) over the term of the financial instrument. Debt issuance costs related to the restructuring of credit facilities are capitalized and amortized as financing costs over the term of the credit facilities.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. These instruments are classified as FVTPL. The Company does not use financial derivatives for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments by recording an asset or liability on the statements of financial position and recognizing changes in the fair value of the instrument in the statements of income (loss) and comprehensive income (loss) for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income (loss) when incurred.

The Company has accounted for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Income Taxes

Current and deferred income taxes are recognized in net income (loss), except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity. When current income tax or deferred income tax arises from the initial accounting for a business combination, the tax effect is included in the accounting for the business combination as goodwill.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period.

The Company follows the balance sheet liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all temporary differences deductible to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share-based Compensation Plans

Expenses related to the Share Award Incentive Plan are determined based on the fair value of the award on the grant date. This amount is expensed over the vesting period of the share award.

Baytex's Share Award Incentive Plan is further described in note 15.

4. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Revenue from Contracts with Customers

IFRS 15 "Revenue from Contracts with Customers" is effective January 1, 2018 and will supersede IAS 11 "Construction Contracts" and IAS 18 "Revenue" and related interpretations. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The new standard also requires disclosures on the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The Company has not yet adopted IFRS 15 and is evaluating its impact on the consolidated financial statements.

Financial Instruments

IFRS 9 "Financial Instruments" replaces IAS 39 "Financial Instruments: Recognition and Measurement", which eliminates the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. In November 2013, the IASB amended IFRS 9 to include the new general hedge accounting model which remains optional, allows more opportunities to apply hedge accounting, and will be effective on January 1, 2018 and applied retroactively to each period presented. The Company has not yet adopted IFRS 9 and is evaluating its impact on the consolidated financial statements.

Leases

IFRS 16 "Leases" replaces IAS 17 "Leases" and is effective January 1, 2019 with early adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers". The new standard will bring most leases on-balance sheet for lessees. The Company has not yet adopted IFRS 16 and is evaluating its impact on the consolidated financial statements.

5. SEGMENTED FINANCIAL INFORMATION

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

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada.
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the states of Texas and 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	
Years Ended December 31	2015	2014	2015	2014	2015	2014	2015	2014
Revenue, net of royalties								
Petroleum and natural gas sales[1]	$ 521,104	$1,382,904	$ 600,320	$ 579,255	$ 8,448	$ 6,863	$ 1,129,872	$1,969,022
Royalties	(67,323)	(265,066)	(174,102)	(174,059)	–	–	(241,425)	(439,125)
	453,781	1,117,838	426,218	405,196	8,448	6,863	888,447	1,529,897
Expenses								
Operating	210,945	272,515	109,242	81,334	–	–	320,187	353,849
Transportation	53,127	83,766	–	–	–	–	53,127	83,766
Blending	27,830	58,120	–	–	–	–	27,830	58,120
Exploration and evaluation	8,775	10,499	–	7,244	–	–	8,775	17,743
Depletion and depreciation	279,744	328,902	377,847	204,461	4,267	3,206	661,858	536,569
Impairment	45,703	37,755	992,851	411,835	–	–	1,038,554	449,590
General and administrative	–	–	–	–	59,406	59,957	59,406	59,957
Acquisition-related	–	–	–	–	–	38,591	–	38,591
Share-based compensation	–	–	–	–	15,344	27,463	15,344	27,463
Financing	–	–	–	–	111,660	90,033	111,660	90,033
Financial derivatives gain	–	–	–	–	(142,729)	(212,524)	(142,729)	(212,524)
Foreign exchange loss	–	–	–	–	210,713	75,381	210,713	75,381
Loss (gain) on disposition of oil and gas properties	1,769	(6,302)	(250)	(43,923)	–	–	1,519	(50,225)
	627,893	785,255	1,479,690	660,951	258,661	82,107	2,366,244	1,528,313
Net income (loss) before income taxes	(174,112)	332,583	(1,053,472)	(255,755)	(250,213)	(75,244)	(1,477,797)	1,584
Income tax expense (recovery)								
Current income tax expense	6,577	–	1,946	53,680	384	195	8,907	53,875
Deferred income tax expense (recovery)	(39,191)	122,346	(324,940)	(25,403)	11,078	(16,427)	(353,053)	80,516
	(32,614)	122,346	(322,994)	28,277	11,462	(16,232)	(344,146)	134,391
Net income (loss)	$(141,498)	$ 210,237	$ (730,478)	$ (284,032)	$(261,675)	$ (59,012)	$(1,133,651)	$ (132,807)
Total oil and natural gas capital expenditures[2]	$ 72,891	$ 360,365	$ 449,796	$2,950,862	$ –	$ –	$ 522,687	$3,311,227

(1) Corporate includes other income related to North Dakota.

(2) Includes acquisitions and divestitures.

As at	December 31, 2015	December 31, 2014
Canadian assets	$ 2,059,903	$ 2,398,241
U.S. assets	3,304,647	3,598,192
Corporate assets	123,948	234,163
Total consolidated assets	$ 5,488,498	$ 6,230,596

6. BUSINESS COMBINATION

On June 11, 2014, Baytex acquired all of the issued and outstanding shares of Aurora Oil & Gas Limited ("Aurora"), a public oil and natural gas company listed on the Australian Stock Exchange and the TSX with properties in the State of Texas, USA. The total consideration for the acquisition was $2.8 billion (including the assumption of approximately $0.9 billion of indebtedness).

The acquisition has been accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:	
Cash paid	$1,920,928
Cash acquired	(54,621)
Bank loan assumed	145,618
Long-term notes assumed	810,061
Total consideration	**$2,821,986**
Allocation of purchase price:	
Trade and other receivables	$ 108,965
Exploration and evaluation assets	391,127
Oil and gas properties	2,520,612
Other plant and equipment	1,209
Goodwill	615,338
Trade and other payables	(242,045)
Financial derivative contracts	(20,083)
Asset retirement obligations	(1,217)
Deferred income tax liabilities	(551,920)
Total net assets acquired	**$2,821,986**

The Company incurred $38.6 million of acquisition-related costs that were expensed in the consolidated statements of income (loss) and comprehensive income (loss) for the year ended December 31, 2014. Goodwill of $615.3 million is attributable to the excess consideration paid over the fair value of assets acquired including the recognition of $551.9 million of deferred income tax liabilities with the remainder attributable to incremental well locations and undeveloped resource rights.

For the period from June 11, 2014 to December 31, 2014, the acquired properties contributed revenues, net of royalties, of $349.4 million and operating income (revenues, net of royalties less operating expenses) of $281.9 million to Baytex's operations. If the acquisition had occurred on January 1, 2014, management estimates for the year ended December 31, 2014, that the acquired properties would have contributed revenues, net of royalties, of approximately $601.2 million and operating income of approximately $501.2 million.

7. EXPLORATION AND EVALUATION ASSETS

	December 31, 2015	December 31, 2014
Balance, beginning of period	$542,040	$162,987
Capital expenditures	5,642	15,824
Corporate acquisition (note 6)	–	391,127
Property acquisition	1,813	12,489
Exploration and evaluation expense	(8,775)	(17,743)
Transfer to oil and gas properties	(38,062)	(10,443)
Divestitures	(1,588)	(40,306)
Foreign currency translation	77,899	28,105
Balance, end of period	**$578,969**	$542,040

As at December 31, 2015, our E&E assets associated with the U.S. CGU were assessed for impairment. In the U.S., the Company estimated the recoverable amount based on management's estimate of the recoverable amount associated with possible reserves as well as the fair value of the undeveloped land. Recoverable amounts for E&E assets exceeded the carrying value, therefore no impairment was recorded at December 31, 2015. At December 31, 2015, there were no indicators of impairment for E&E assets relating to CGUs in Canada and therefore no impairment test was performed.

8. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2013	**$3,223,768**	**$ (1,000,982)**	**$2,222,786**
Capital expenditures	750,247	–	750,247
Corporate acquisition (note 6)	2,520,612	–	2,520,612
Property acquisitions	85,600	–	85,600
Transferred from exploration and evaluation assets	10,443	–	10,443
Change in asset retirement obligations	69,844	–	69,844
Divestitures	(426,477)	96,916	(329,561)
Foreign currency translation	197,723	(10,953)	186,770
Depletion	–	(532,825)	(532,825)
Balance, December 31, 2014	**$6,431,760**	**$ (1,447,844)**	**$4,983,916**
Capital expenditures	515,397	–	515,397
Property acquisitions	551	–	551
Transferred from exploration and evaluation assets	38,062	–	38,062
Change in asset retirement obligations	10,722	–	10,722
Divestitures	(20,096)	19,449	(647)
Impairment	(755,613)	–	(755,613)
Foreign currency translation	607,885	(68,509)	539,376
Depletion	–	(657,589)	(657,589)
Balance, December 31, 2015	**$6,828,668**	**$ (2,154,493)**	**$4,674,175**

For the year ended December 31, 2015, the Company recorded total impairments of $1,038.6 million (2014 – $449.6 million).

As a result of further declining commodity prices, oil and gas properties were reassessed for impairment in 2015. Impairment of $992.9 million ($741.3 million net of tax) was recorded in the U.S. CGU as a reduction to oil and gas properties of $709.9 million and to goodwill of $282.9 million. The recoverable amount for the U.S. CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment at December 31, 2015. The recoverable amount of oil and gas properties of $3,222.0 million for the U.S. CGU was estimated based on their fair value less costs of disposals at December 31, 2015.

For impairment assessments of oil and gas properties, the Company estimates the recoverable amount using a discounted cash flow model based on an independent reserve report approved by the Board of Directors on an annual basis and a pre-tax discount rate. The reserve report is based on an estimated remaining reserve life up to a maximum of 50 years. The forecasted cash flows include reserves where there is at least a 50% probability that the estimated proved plus probable reserves will be recovered and in the case of the U.S. assets, possible reserves as well as fair value of undeveloped land acreage. The recoverable amount was determined using a pre-tax discount rate of 10%.

The recoverable amounts were calculated at December 31, 2015 using the following benchmark reference prices for the years 2016 to 2020 adjusted for commodity differentials specific to the Company:

	2016	2017	2018	2019	2020
WTI crude oil (US$/bbl)	41.44	60.00	70.00	80.00	81.20
NYMEX natural gas (US$/MMBtu)	2.50	3.00	3.50	4.00	4.25
Exchange rate (CAD/USD)	1.33	1.25	1.20	1.18	1.18

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2020 have been adjusted for inflation at an annual rate of 1.5%.

The fair value less costs of disposal values used to determine the recoverable amounts of each CGU are classified as Level 3 fair value measures as they are based on the Company's estimate of key assumptions that are not based on observable market data.

The results of the impairment test are sensitive to changes in any of the key judgments, such as a revision in reserves, a change in forecast commodity prices, expected royalties, future development capital expenditures or expected future production costs, which could decrease or increase the recoverable amounts of assets and result in additional impairment or recovery of impairment.

The following table demonstrates the effect of the assumed discount rate and the effect of forecast commodity prices estimates on impairment recorded for the year ended December 31, 2015. The sensitivity is based on a one per cent increase in the assumed discount rate and a five percent decrease in the forecast commodity price estimate.

	Increase in Discount Rate of 1 percent	Decrease in Commodity Prices of 5 percent
Peace River CGU	$ –	$108,000
Conventional CGU	–	14,000
Lloydminster CGU	–	93,000
U.S. CGU	139,500	321,000
Impairment increase (decrease)	$139,500	$536,000

In November 2015, the Company completed a disposition of certain non-core assets in its Lloydminster CGU and recorded an impairment of $45.7 million.

2014 Dispositions

On September 24, 2014, Baytex Energy USA LLC, an indirect wholly-owned subsidiary of Baytex, disposed of its interests located in North Dakota, which consisted of oil and gas properties, exploration and evaluation assets and other plant and equipment with carrying values of $294.0 million, $32.5 million and $2.0 million, respectively, for cash proceeds of $341.6 million resulting in a before tax gain of $13.1 million. The Company also realized a $15.5 million gain on its foreign currency translation adjustment in accumulated other comprehensive income (loss) which was reclassified on disposition.

During 2014, Baytex disposed of certain non-core assets in Canada, consisting of $34.8 million of oil and gas properties and $7.2 million of exploration and evaluation assets, for net cash proceeds of $45.7 million. Gains totaling $3.7 million were recognized in the statements of income (loss) and comprehensive income (loss).

9. OTHER PLANT AND EQUIPMENT

	Cost	Accumulated depreciation	Net book value
Balance, December 31, 2013	**$69,510**	**$(39,951)**	**$29,559**
Capital expenditures	8,283	–	8,283
Corporate acquisition (note 6)	1,209	–	1,209
Dispositions	(2,496)	1,327	(1,169)
Foreign currency translation	202	(72)	130
Depreciation	–	(3,744)	(3,744)
Balance, December 31, 2014	**$76,708**	**$(42,440)**	**$34,268**
Capital expenditures	3,577	–	3,577
Dispositions	(7,684)	–	(7,684)
Foreign currency translation	277	(147)	130
Depreciation	–	(4,267)	(4,267)
Balance, December 31, 2015	**$72,878**	**$(46,854)**	**$26,024**

Field inventory held is valued at the lower of cost, using the weighted average cost method, or net realizable value and is not depreciated.

10. GOODWILL

	December 31, 2015	December 31, 2014
Balance, beginning of period	**$ 245,065**	$ 37,755
Acquired goodwill (note 6)	**–**	615,338
Impairment	**(282,941)**	(449,590)
Foreign currency translation	**37,876**	41,562
Balance, end of period	**$ –**	$ 245,065

For the year ended December 31, 2015, the Company recorded impairments on its U.S. CGU including a reduction to goodwill of $282.9 million. The recoverable amount of the U.S. CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment. The decline in commodity prices, in particular crude oil, resulted in a reduction of expected future net cash flows to an amount lower than the combined carrying value of the assets and associated goodwill.

For the year ended December 31, 2014, the Company recorded a goodwill impairment of $449.6 million, including $37.8 million of goodwill recognized on the 2004 acquisition of certain conventional oil and gas properties in the Conventional CGU and $411.8 million of goodwill related to the U.S. CGU.

Recoverable amounts related to the goodwill impairment test were determined using the key assumptions listed in notes 7 and 8.

11. BANK LOAN

	December 31, 2015	December 31, 2014
Bank loan – principal	**$ 256,749**	$ 666,886
Unamortized debt issuance costs	**(4,577)**	(3,574)
Bank loan	**$ 252,172**	$ 663,312

Baytex has revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a $50 million operating loan, a $750 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"). 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 period at any time). Advances (including letters of credit) under the Revolving Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex exceeds any of the covenants under the Revolving Facilities, its ability to pay dividends to its shareholders, borrow funds or increase the facilities may be restricted.

The weighted average interest rate on the credit facilities for the year ended December 31, 2015 was 3.32% (3.25% for the year ended December 31, 2014). Baytex is in compliance with all covenants at December 31, 2015.

12. LONG-TERM NOTES

	December 31, 2015	December 31, 2014
9.875% senior unsecured notes (US$7,900 – principal)[1]	$ –	$ 9,165
7.5% senior unsecured notes (US$6,400 – principal)	8,858	7,425
6.75% senior unsecured debentures (US$150,000 – principal)	207,600	174,015
5.125% senior unsecured debentures (US$400,000 – principal)	553,600	464,040
6.625% senior unsecured debentures (Cdn$300,000 – principal)	300,000	300,000
5.625% senior unsecured debentures (US$400,000 – principal)	553,600	464,040
Total long-term notes – principal	1,623,658	1,418,685
Unamortized debt issuance costs	(20,901)	(19,653)
Total long-term notes – net of unamortized debt issuance costs	**$1,602,757**	$1,399,032

(1) Redeemed on February 27, 2015.

Pursuant to the acquisition of Aurora (note 6), Baytex assumed US$365 million of 9.875% senior unsecured notes due February 15, 2017 (the "2017 Notes") and US$300 million of 7.500% senior unsecured notes due April 1, 2020 (the "2020 Notes" and, together with the 2017 Notes, the "Notes").

On April 22, 2014, Baytex commenced a cash tender offer and consent solicitation for the Notes at a price (per US$1,000 of principal amount) of US$1,107.34 for the 2017 Notes and US$1,138.97 for the 2020 Notes. Upon closing of the tender offers on June 11, 2014, Baytex purchased and cancelled US$357.1 million (97.8% of total outstanding) of the 2017 Notes and US$293.6 million (97.9% of total outstanding) of the 2020 Notes. The remaining Notes are recorded at fair value by applying the tender premium on the Notes on the date of acquisition. The premium will be amortized using the effective interest rate of 6.7% for the 2017 Notes and 5.3% for the 2020 Notes. On February 27, 2015, the Company redeemed all of the outstanding 2017 Notes at a price of US$8.3 million plus accrued interest. The remaining 2020 notes are redeemable at the Company's option, in whole or in part, commencing on April 1, 2016 in accordance with the terms of the indenture agreements.

13. ASSET RETIREMENT OBLIGATIONS

	December 31, 2015	December 31, 2014
Balance, beginning of year	**$286,032**	$221,628
Liabilities incurred	**4,964**	18,516
Liabilities settled	**(10,888)**	(14,528)
Liabilities acquired	**593**	2,271
Liabilities divested	**(10,578)**	(25,305)
Corporate acquisition (note 6)	**–**	1,217
Accretion	**6,262**	7,251
Change in estimate[(1)]	**33,266**	31,599
Changes in discount rates and inflation rates	**(17,523)**	42,763
Foreign currency translation	**3,874**	620
Balance, end of year	**$296,002**	$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.

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years. The undiscounted amount of estimated cash flow required to settle the asset retirement obligations is $561.4 million (December 31, 2014 – $630.9 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2015 using an estimated annual inflation rate of 1.50% (December 31, 2014 – 1.75%) and discounted at a risk free rate of 2.25% (December 31, 2014 – 2.25%) is $296.0 million (December 31, 2014 – $286.0 million).

14. 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 December 31, 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	1,092	41,836
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, December 31, 2015	**210,583**	**$4,296,831**

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.

Concurrent with the closing of the acquisition of Aurora on June 11, 2014, Baytex exchanged the 38.4 million subscription receipts issued in February 2014, for 38.4 million common shares and a dividend equivalent payment of $0.88 per subscription receipt (representing the four dividends declared from the date of issuance of the subscription receipts to the date of closing of the acquisition). Issuance costs of $93.7 million ($78.5 million, after tax), including the aggregate dividend equivalent payment of $33.8 million, were incurred and recorded as a reduction to shareholders' capital.

Baytex has a Dividend Reinvestment Plan (the "DRIP") that allows eligible holders in Canada and the United States to reinvest their monthly cash dividends to acquire additional common shares. At the discretion of Baytex, common shares will either be issued from treasury or acquired in the open market at prevailing market prices. Pursuant to the terms of the DRIP, common shares are issued from treasury at a three percent discount to the arithmetic average of the daily volume weighted average trading prices of the common shares on the Toronto Stock Exchange (in respect of participants resident in Canada or any jurisdiction other than the United States) or the New York Stock Exchange (in respect of participants resident in the United States) for the period commencing on the second business day after the dividend record date and ending on the second business day immediately prior to the dividend payment date. Baytex reserves the right at any time to change or eliminate the discount on common shares acquired through the DRIP from treasury. During the year ended December 31, 2015, a total of 4,928,529 common shares were issued in accordance with this plan (2014 – 2,757,315).

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

During the year ended December 31, 2015, the Company declared dividends of $0.80 per share (2014 – $2.64 per share) totaling $154.0 million (2014 – $395.6 million) ($96.6 million, net of DRIP (2014 – $301.1 million)). The Company suspended the monthly dividend in September 2015 in light of low commodity prices.

15. SHARE AWARD INCENTIVE PLAN

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.3% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents as described below) with such common shares to be issued as to one-sixth on the first anniversary date of the grant and as to one-sixth every six months thereafter (with the last issuance to occur 42 months following the grant date). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents as described below) multiplied by a payout multiplier with such common shares to be issued as to one-sixth on the first anniversary date of the grant and as to one-sixth every six months thereafter (with the last issuance to occur 42 months following the grant date). The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payment of dividends from the grant date to the applicable issue date.

The Company recorded compensation expense related to the share awards of $15.3 million for the year ended December 31, 2015 (year ended December 31, 2014 – $27.5 million).

The fair value of share awards is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate, which has been estimated at a weighted average of 14.6% (2014 – 10.4%) of outstanding share awards. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions and actual forfeiture rates. The estimated weighted average fair value for share awards at the measurement date is $17.17 per restricted award and performance award granted during the year ended December 31, 2015 (year ended December 31, 2014 – $43.79 per restricted award and performance award).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[1]	Total number of share awards
Balance, December 31, 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	615	503	1,118
Vested and converted to common shares	(432)	(382)	(814)
Forfeited	(201)	(123)	(324)
Balance, December 31, 2015	**729**	**613**	**1,342**

(1) Based on underlying units before applying performance multiplier.

16. NET INCOME (LOSS) PER SHARE

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

	Years Ended December 31					
	2015			2014		
	Net loss	**Common shares (000s)**	**Net loss per share**	Net loss	Common shares (000s)	Net loss per share
Net income (loss) – basic	**$ (1,133,651)**	**198,207**	**$ (5.72)**	$ (132,807)	148,932	$ (0.89)
Dilutive effect of share awards	**–**	**–**	**–**	–	–	–
Dilutive effect of share rights	**–**	**–**	**–**	–	–	–
Net income (loss) – diluted	**$ (1,133,651)**	**198,207**	**$ (5.72)**	$ (132,807)	148,932	$ (0.89)

For the year ended December 31, 2015, 1.3 million share awards were anti-dilutive (December 31, 2014 – 1.4 million share awards and 0.1 million share rights).

17. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2015	2014
Net income (loss) before income taxes	$ (1,477,797)	$ 1,584
Expected income taxes at the statutory rate of 26.24% (2014 – 25.47%)(1)	(387,774)	403
Increase (decrease) in income taxes resulting from:		
Share-based compensation	4,027	6,465
Non-taxable portion of foreign exchange loss	27,910	9,323
Effect of change in income tax rates(1)	13,246	800
Effect of rate adjustments for foreign jurisdictions	(120,943)	(8,544)
Effect of change in deferred tax benefit not recognized(2)	40,142	1,521
Goodwill impairment	74,025	114,511
Other	5,221	9,912
Income tax (recovery) expense	$ (344,146)	$ 134,391

(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%).

(2) A deferred income tax asset has not been recognized for allowable capital losses of $149 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated senior unsecured notes.

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 is entitled to deduct the non-capital losses, that its tax filings to-date are correct and 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.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2015	Recognized in Net Loss	Acquired in Business Combination	Share Issuance Costs	Foreign Currency Translation Adjustment	December 31, 2015
Taxable temporary differences:						
Petroleum and natural gas properties	$(1,136,083)	$ 30,613	$ –	$ –	$ –	$ (1,105,470)
Financial derivatives	(45,950)	15,989	–	–	–	(29,961)
Deferred income	(81,979)	53,592	–	–	–	(28,387)
Other	(7,222)	103,403	–	7,099	(109,875)	(6,595)
Deductible temporary differences:						
Asset retirement obligations	74,918	8,271	–	–	–	83,189
Financial derivatives	5,341	(3,759)	–	–	–	1,582
Non-capital losses	227,370	156,080	–	–	–	383,450
Finance costs	58,073	(11,136)	–	–	–	46,937
Net deferred income tax liability(1)	$ (905,532)	$ 353,053	$ –	$ 7,099	$(109,875)	$ (655,255)

(1) Non-capital loss carry-forwards at December 31, 2015 totaled $1,110.0 million and expire from 2023 to 2035.

As at	January 1, 2014	Recognized in Net Loss	Acquired in Business Combination	Share Issuance Costs	Foreign Currency Translation Adjustment	December 31, 2014
Taxable temporary differences:						
Petroleum and natural gas properties	$ (344,045)	$ 48,613	$ (840,650)	$ –	$ –	**$ (1,136,082)**
Financial derivatives	–	(45,950)	–	–	–	**(45,950)**
Deferred income	(44,044)	(37,935)	–	–	–	**(81,979)**
Other	(1,772)	19,244	–	15,258	(39,953)	**(7,223)**
Deductible temporary differences:						
Asset retirement obligations	62,089	13,707	(878)	–	–	**74,918**
Financial derivatives	2,397	2,944	–	–	–	**5,341**
Non-capital losses	65,558	(81,297)	243,109	–	–	**227,370**
Finance costs	11,416	158	46,499	–	–	**58,073**
Net deferred income tax liability(1)	$ (248,401)	$ (80,516)	$ (551,920)	$ 15,258	$ (39,953)	**$ (905,532)**

(1) Non-capital loss carry-forwards at December 31, 2014 totaled $685.7 million and expire from 2023 to 2034.

18. FINANCING COSTS

Financing costs are comprised of the following:

	Years Ended December 31 2015	2014
Interest on bank loan	**$ 14,303**	$ 21,854
Interest on long-term notes	**89,101**	59,231
Non-cash financing costs	**1,994**	1,697
Accretion on asset retirement obligations	**6,262**	7,251
Financing costs	**$ 111,660**	$ 90,033

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. To estimate fair values of its financial instruments, Baytex uses quoted market prices when available, or third-party models and valuation methodologies that use observable market data. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan and long-term notes, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its carrying value as it is at a market rate of interest. The fair value of the long-term notes are based on the trading value of the senior unsecured notes.

Fair Value of Financial Instruments

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

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

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

	December 31, 2015		December 31, 2014		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL[1]					
Cash	$ 247	$ 247	$ 1,142	$ 1,142	Level 1
Derivatives	110,990	110,990	220,644	220,644	Level 2
Total FVTPL[1]	$ 111,237	$ 111,237	$ 221,786	$ 221,786	
Loans and receivables					
Trade and other receivables	$ 98,093	$ 98,093	$ 203,259	$ 203,259	–
Total loans and receivables	$ 98,093	$ 98,093	$ 203,259	$ 203,259	
Financial Liabilities					
FVTPL[1]					
Derivatives	$ –	$ –	$ (54,839)	$ (54,839)	Level 2
Total FVTPL[1]	$ –	$ –	$ (54,839)	$ (54,839)	
Other financial liabilities					
Trade and other payables	$ (267,838)	$ (267,838)	$ (398,261)	$ (398,261)	–
Dividends payable to shareholders	–	–	(16,811)	(16,811)	–
Bank loan	(252,172)	(252,172)	(663,312)	(663,312)	–
Long-term notes	(1,602,757)	(1,287,679)	(1,399,032)	(1,251,117)	Level 2
Total other financial liabilities	$ (2,122,767)	$ (1,807,689)	$ (2,477,416)	$ (2,329,501)	

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

There were no transfers between Level 1 and 2 in either 2015 or 2014.

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign Currency Risk

Baytex is exposed to fluctuations in foreign currency as a result of the U.S. dollar portion of its bank loan and long-term notes, crude oil sales based on U.S. dollar benchmark prices and commodity contracts that are settled in U.S. dollars. The Company's net income (loss) and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of currency exchange rate fluctuations, the Company may enter into agreements to fix the Canadian dollar–U.S. dollar exchange rate. At December 31, 2015, the Company did not have any currency derivative contracts outstanding.

A $0.01 increase and decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income (loss) before income taxes by approximately $11.2 million.

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

	Assets		Liabilities	
	December 31, 2015	December 31, 2014	**December 31, 2015**	December 31, 2014
U.S. dollar denominated	**US$124,218**	US$329,716	**US$1,240,308**	US$1,295,391

Interest Rate Risk

The Company's interest rate risk arises from the floating rate credit facilities (note 11). As at December 31, 2015, $256.7 million of the Company's total debt is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income (loss) before income taxes for the year ended December 31, 2015 by approximately $3.4 million. Baytex uses a combination of short-term and long-term debt to finance operations.

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 December 31, 2015, $10.3 million of gross liabilities have been netted against assets (nil at December 31, 2014).

When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 31, 2015, a 10% increase in oil prices would decrease the unrealized gain at December 31, 2015 by $28.4 million, while a 10% decrease would increase the unrealized gain at December 31, 2015 by $16.8 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2015, a 10% increase in natural gas prices would decrease the unrealized gain at December 31, 2015 by $2.5 million, while a 10% decrease would increase the unrealized gain at December 31, 2015 by $3.2 million.

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	January 2016 to March 2016	1,000 bbl/d	US$65.33	WTI
Fixed – Sell	January 2016 to June 2016	2,000 bbl/d	US$62.50	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	7,500 bbl/d	US$60.13/US$50/US$40	WTI
Producer 3-way option[2]	January 2016 to December 2017	2,000 bbl/d	US$60/US$50/US$40	WTI
Basis swap	January 2016 to December 2016	2,000 bbl/d	WTI less US$13.00	WCS
Basis swap	February 2016 to December 2016	500 bbl/d	WTI less US$13.85	WCS
Fixed – Sell[3]	March 2016 to April 2016	3,000 bbl/d	US$34.80	WTI
Basis swap[3]	March 2016 to December 2016	2,000 bbl/d	WTI less US$13.40	WCS
Basis swap[3]	April 2016	3,000 bbl/d	WTI less US$12.82	WCS
Basis swap[3]	April 2016 to June 2016	500 bbl/d	WTI less US$12.45	WCS
Basis swap[3]	July 2016 to September 2016	500 bbl/d	WTI less US$12.30	WCS
Basis swap[3]	October 2016 to December 2016	500 bbl/d	WTI less US$13.45	WCS
Basis swap[3]	January 2017 to December 2017	1,500 bbl/d	WTI less US$13.42	WCS

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in the $60/$50/$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives 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 December 31, 2015.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	January 2016 to December 2016	10,000 mmBtu/d	US$3.19	NYMEX
Fixed – Sell[2]	February 2016 to December 2016	5,000 mmBtu/d	US$2.57	NYMEX
Fixed – Sell[2]	January 2017 to December 2017	10,000 mmBtu/d	US$2.83	NYMEX
Fixed – Sell	January 2016 to December 2016	15,000 GJ/d	$2.96	AECO
Fixed – Sell[2]	February 2016 to December 2016	5,000 GJ/d	$2.53	AECO
Fixed – Sell[2]	January 2017 to December 2017	5,000 GJ/d	$2.81	AECO

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Contracts entered subsequent to December 31, 2015.

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):

	Years Ended December 31	
	2015	2014
Realized financial derivatives (gain) loss	**$ (197,545)**	$ (27,324)
Unrealized financial derivatives (gain) loss – commodity	**54,318**	(191,097)
Unrealized financial derivate (gain) loss – redemption feature on long-term notes	**498**	5,897
Financial derivatives (gain) loss	**$ (142,729)**	$ (212,524)

Physical Delivery Contracts

As at December 31, 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	January 2016 to December 2016	2,000 bbl/d	WTI less US$13.68

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

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing dividends and capital expenditures. As at December 31, 2015, Baytex had available unused bank credit facilities in the amount of $820.1 million (as at December 31, 2014 – $565.1 million). In the event the Company is not able to comply with the financial covenants contained in agreements with its lenders, the Company's ability to access additional debt may be restricted.

The timing of cash outflows relating to financial liabilities as at December 31, 2015 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 267,838	$ 267,838	$ –	$ –	$ –
Bank loan[(1)(2)]	256,749			256,749	
Long-term notes[(2)]	1,623,658	–	–	8,858	1,614,800
Interest on long-term notes	620,144	94,064	188,129	186,969	150,982
	$ 2,768,389	$ 361,902	$ 188,129	$ 452,576	$ 1,765,782

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

(2) Principal amount of instruments.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. Most of the Company's trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit and/or parental guarantees may be obtained prior to the commencement of business with certain counterparties. None of the Company's financial assets are secured by any other type of collateral. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on accounts receivable at December 31, 2015 relates to accrued revenues for December 2015. Accounts receivables from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. At December 31, 2015, $37.5 million of accounts receivable relates to joint interest receivables from the operator of our joint operations in the Eagle Ford.

Should Baytex determine that the ultimate collection of a receivable is in doubt, the carrying amount of accounts receivable is reduced by the use of an allowance for doubtful accounts and a charge to net income (loss). If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. For the year ended December 31, 2015, $0.1 million was added to the allowance for doubtful accounts (2014 – $0.7 million written-off).

As at December 31, 2015, allowance for doubtful accounts was $1.4 million (2014 – $1.3 million). In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2015, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $1.4 million (2014 – $1.0 million).

The Company's trade and other receivables were aged as follows at December 31, 2015:

Trade and Other Receivables Aging[1]	December 31, 2015
Current (less than 30 days)	$ 88,827
31-60 days	1,422
61-90 days	589
Past due (more than 90 days)	2,787
	$ 93,625

(1) Excludes $4.5 million of prepaid expenses that have been classified as Trade and other receivables.

20. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Years Ended December 31	
	2015	2014
Trade and other receivables	$ 117,489	$ 63,002
Trade and other payables	(144,566)	(81,528)
	$ (27,077)	$ (18,526)
Changes in non-cash working capital related to:		
Operating activities	$ 43,891	$ 31,890
Investing activities	(70,968)	(50,416)
	$ (27,077)	$ (18,526)

Foreign Exchange

	Years Ended December 31	
	2015	2014
Unrealized foreign exchange loss	$ 213,999	$ 75,011
Realized foreign exchange(gain) loss	(3,286)	370
Foreign exchange loss	$ 210,713	$ 75,381

Income Statement Presentation

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2015	2014
Operating	$ 13,180	$ 13,262
General and administrative	28,432	36,269
Total employee compensation costs	$ 41,612	$ 49,531

21. COMMITMENTS AND CONTINGENCIES

Baytex has 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 cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of December 31, 2015, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Operating leases	$ 50,305	8,063	16,501	15,589	10,152
Processing agreements	52,147	9,219	10,340	9,043	23,545
Transportation agreements	75,392	13,910	24,556	23,371	13,555
Total	$ 177,844	$ 31,192	$ 51,397	$ 48,003	$ 47,252

Baytex also has 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.

Operating lease and sublease payments recognized as an expense during the year ended December 31, 2015 were $8.0 million (December 31, 2014 – $8.0 million). Baytex has entered into operating leases on office buildings in the ordinary course of business. The Company's operating lease agreements do not contain any contingent rent clauses. The Company has the option to renew or extend the leases on its office building with the new lease terms to be based on current market prices. None of the operating lease agreements contain purchase options or escalation clauses or any restrictions regarding dividends, further leases or additional debt.

The litigation and claims that Baytex is engaged with, which arose in the normal course of operations, are not expected to materially affect the Company's financial position or reported results of operations.

At December 31, 2015, Baytex had $12.4 million of outstanding letters of credit (December 31, 2014 – $10.1 million).

22. RELATED PARTIES

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Transactions with key management personnel (including directors) are noted in the table below:

	Years Ended December 31	
	2015	2014
Short-term employee benefits	$ 6,831	$ 9,319
Share-based compensation	12,032	12,989
Termination payments	549	1,943
Total compensation for key management personnel	$ 19,412	$ 24,251

23. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of its business through maintenance of investor, creditor and market confidence.

Baytex considers its capital structure to include net debt and shareholders' equity. Baytex monitors capital based on the current and projected ratio of net debt to funds from operations and the current and projected level of its undrawn credit facilities. Historically and under normal operating conditions, the Company's objective is to maintain a net debt to funds from operations ratio of less than two times and to have access to undrawn credit facilities of not less than $100 million. The net debt to funds from operations ratio may increase beyond the two times and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors including changes to commodity prices, acquisitions, and changes in the credit market.

These objectives and strategy are reviewed on an annual basis. With the significant decrease in commodity prices in 2015, Baytex's net debt to funds from operations ratio has exceeded its target but the Company has maintained access to at least $100 million in undrawn credit facilities. The Company's financial strategy is designed to maintain a flexible capital structure consistent with the objectives stated above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to manage its capital, the Company may adjust its level of capital spending, issue new shares or debt, adjust the amount of its dividends or sell assets to reduce debt. In the current commodity environment the Company's objective is to have access to undrawn credit facilities of not less than $100 million and to manage its capital to maintain liquidity.

As at December 31, 2015, Baytex is in compliance with all financial covenants relating to its senior unsecured notes and Revolving Facilities.

	Years Ended December 31	
	2015	2014
Cash flow from operating activities	$ 549,420	$ 897,152
Change in non-cash working capital	(43,891)	(31,890)
Asset retirement expenditures	10,888	14,528
Funds from operations	$ 516,417	$ 879,790

	As at December 31	
	2015	2014
Bank loan – principal	$ 256,749	$ 666,886
Long-term notes – principal	1,623,658	1,418,685
Trade and other payables	267,838	398,261
Dividends payable to shareholders	–	16,811
Cash	(247)	(1,142)
Trade and other receivables	(98,093)	(203,521)
Net debt	$ 2,049,905	$ 2,295,980

	As at December 31	
	2015	2014
Available undrawn credit facilities	$ 820,051	$ 565,134
Net debt to funds from operations ratio	4.0	2.6

Petroleum and Natural Gas Reserves as at December 31, 2015

Baytex's year-end 2015 proved and probable reserves were evaluated by Sproule Unconventional Limited ("Sproule") and Ryder Scott Company, L.P. ("Ryder Scott"), both independent qualified reserves evaluators. Sproule prepared our reserves report by consolidating the Canadian properties evaluated by Sproule with the United States properties evaluated by Ryder Scott, in each case using Sproule's December 31, 2015 forecast price and cost assumptions. Ryder Scott also evaluated the possible reserves associated with our Eagle Ford assets. All of Baytex's oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. The following table sets forth our gross and net reserves volumes at December 31, 2015 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

CANADA

	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
Reserves Category	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
Proved						
Developed Producing	34,199	25,847	529	485	2,758	2,522
Developed Non-Producing	3,469	2,910	7,801	6,917	45	40
Undeveloped	27,362	22,498	5,429	4,522	99	118
Total Proved	65,030	51,254	13,758	11,925	2,902	2,681
Probable	37,883	29,642	55,882	43,421	2,420	2,100
Total Proved Plus Probable	102,913	80,896	69,640	55,346	5,323	4,781

CANADA

	Forecast Prices and Costs					
	Natural Gas Liquids		Conventional Natural Gas		Oil Equivalent(3)	
Reserves Category	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mbbl)	*(mbbl)*	*(mmcf)*	*(mmcf)*	*(mboe)*	*(mboe)*
Proved						
Developed Producing	1,364	1,005	56,397	46,976	48,248	37,688
Developed Non-Producing	4	3	349	327	11,377	9,925
Undeveloped	1,376	1,089	35,254	29,511	40,142	33,145
Total Proved	2,745	2,096	92,000	76,814	99,767	80,758
Probable	3,081	2,285	85,538	70,169	113,523	89,143
Total Proved Plus Probable	5,826	4,381	177,538	146,982	213,290	169,900

UNITED STATES

	Forecast Prices and Costs					
	Tight Oil		Natural Gas Liquids		Shale Gas	
Reserves Category	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*
Proved						
Developed Producing	20,403	15,003	25,812	19,072	56,753	41,948
Developed Non-Producing	–	–	–	–	–	–
Undeveloped	28,812	21,155	57,897	42,491	138,014	101,130
Total Proved	49,215	36,158	83,710	61,563	194,767	143,078
Probable	4,551	3,343	16,263	11,904	40,038	29,357
Total Proved Plus Probable	53,765	39,501	99,972	73,467	234,805	172,435
Possible(4)(5)	16,920	12,505	88,902	65,436	210,894	155,206
Total Proved Plus Probable Plus Possible	70,685	52,006	188,874	138,903	445,699	327,641

UNITED STATES

	Forecast Prices and Costs			
	Conventional Natural Gas		Oil Equivalent(3)	
Reserves Category	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mmcf)	*(mmcf)*	*(mboe)*	*(mbbl)*
Proved				
Developed Producing	27,859	20,502	60,317	44,483
Developed Non-Producing	–	–	–	–
Undeveloped	29,021	21,330	114,548	84,056
Total Proved	56,880	41,832	174,865	128,539
Probable	5,991	4,406	28,486	20,874
Total Proved Plus Probable Possible	62,871	46,238	203,350	149,413
Possible(4)(5)	20,049	14,799	144,312	106,276
Total Proved Plus Probable Plus Possible	82,920	61,037	347,662	255,689

TOTAL

	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
Reserves Category	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
Proved						
Developed Producing	34,199	25,847	529	485	2,758	2,522
Developed Non-Producing	3,469	2,910	7,801	6,917	45	40
Undeveloped	27,362	22,498	5,429	4,522	99	118
Total Proved	65,030	51,254	13,758	11,925	2,902	2,681
Probable	37,883	29,642	55,882	43,421	2,420	2,100
Total Proved Plus Probable	102,913	80,896	69,640	55,346	5,323	4,781
Possible(4)(5)	–	–	–	–	–	–
Total Proved Plus Probable Plus Possible	102,913	80,896	69,640	55,346	5,323	4,781

TOTAL

Reserves Category	Forecast Prices and Costs					
	Tight Oil		Natural Gas Liquids		Shale Gas	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*
Proved						
Developed Producing	20,403	15,003	27,176	20,077	56,753	41,948
Developed Non-Producing	–	–	4	3	–	–
Undeveloped	28,812	21,155	59,273	43,580	138,014	101,130
Total Proved	49,215	36,158	86,454	63,659	194,767	143,078
Probable	4,551	3,343	19,344	14,188	40,038	29,357
Total Proved Plus Probable	53,765	39,501	105,798	77,848	234,805	172,435
Possible[4][5]	16,920	12,505	88,902	65,436	210,894	155,206
Total Proved Plus Probable Plus Possible	70,685	52,006	194,699	143,284	445,699	327,641

TOTAL

Reserves Category	Forecast Prices and Costs			
	Conventional Natural Gas		Oil Equivalent[3]	
	Gross[1]	Net[2]	Gross[1]	Net[2]
	(mmcf)	*(mmcf)*	*(mboe)*	*(mboe)*
Proved				
Developed Producing	84,256	67,477	108,565	82,171
Developed Non-Producing	349	327	11,377	9,925
Undeveloped	64,275	50,841	154,690	117,201
Total Proved	148,880	118,646	274,633	209,297
Probable	91,530	74,575	142,008	110,017
Total Proved Plus Probable	240,409	193,220	416,640	319,313
Possible[4][5]	20,049	14,799	144,312	106,276
Total Proved Plus Probable Plus Possible	260,458	208,019	560,952	425,589

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs 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.

(4) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(5) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in table may not add due to rounding.

Reconciliation of Gross Reserves[1][2]
By Principal Product Type
Forecast Prices and Costs

	Heavy Oil			Bitumen		
Gross Reserves Category	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
December 31, 2014	78,145	39,777	117,922	18,058	73,054	91,112
Extensions	1,121	4,592	5,713	–	–	–
Infill Drilling	929	620	1,549	–	–	–
Improved Recoveries	–	175	175	–	–	–
Technical Revisions	(475)	(6,677)	(7,151)	(3,225)	(17,194)	(20,419)
Discoveries	11	4	15	–	–	–
Acquisitions	1,515	511	2,026	–	–	–
Dispositions	(977)	(922)	(1,900)	–	–	–
Economic Factors	(3,341)	(196)	(3,537)	(211)	22	(189)
Production	(11,898)	–	(11,898)	(864)	–	(864)
December 31, 2015	65,030	37,883	102,913	13,758	55,882	69,640

	Light and Medium Crude Oil			Tight Oil		
Gross Reserves Category	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
December 31, 2014	3,736	2,496	6,232	49,333	4,546	53,879
Extensions	–	–	–	–	–	–
Infill Drilling	1	–	1	4,971	473	5,444
Improved Recoveries	–	–	–	–	–	–
Technical Revisions	347	(333)	15	989	(328)	661
Discoveries	–	–	–	–	–	–
Acquisitions	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–
Economic Factors	(521)	257	(265)	(457)	(140)	(597)
Production	(660)	–	(660)	(5,622)	–	(5,622)
December 31, 2015	2,902	2,420	5,323	49,215	4,551	53,765

	Natural Gas Liquids			Shale Gas		
Gross Reserves Category	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*	*(mmcf)*
December 31, 2014	81,583	12,753	94,336	185,604	22,543	208,147
Extensions	49	428	477	–	–	–
Infill Drilling	13,339	9,152	22,491	28,783	22,560	51,342
Improved Recoveries	–	–	–	–	–	–
Technical Revisions	(1,740)	(2,871)	(4,611)	(7,017)	(4,759)	(11,776)
Discoveries	–	–	–	–	–	–
Acquisitions	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–
Economic Factors	(521)	(119)	(640)	(762)	(305)	(1,067)
Production	(6,256)	–	(6,256)	(11,841)	–	(11,841)
December 31, 2015	86,454	19,344	105,798	194,767	40,038	234,805

	Conventional Natural Gas			Oil Equivalent[3]		
Gross Reserves Category	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mmcf)	*(mmcf)*	*(mmcf)*	*(mboe)*	*(mboe)*	*(mboe)*
December 31, 2014	128,762	71,891	200,653	283,249	148,365	431,614
Extensions	1,263	10,107	11,369	1,381	6,704	8,085
Infill Drilling	8,573	1,463	10,036	25,465	14,249	39,714
Improved Recoveries	–	–	–	–	175	175
Technical Revisions	38,990	10,593	49,583	1,225	(26,430)	(25,204)
Discoveries	–	–	–	11	4	15
Acquisitions	–	–	–	1,515	511	2,026
Dispositions	–	–	–	(977)	(922)	(1,900)
Economic Factors	(7,057)	(2,525)	(9,582)	(6,354)	(648)	(7,002)
Production	(21,651)	–	(21,651)	(30,882)	–	(30,882)
December 31, 2015	148,880	91,529	240,409	274,633	142,008	416,640

Notes:

(1) *"Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.*

(2) *Reserves information as at December 31, 2015 and 2014 is prepared in accordance with NI 51-101.*

(3) *Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs 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.*

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2015 by Q4/2015 production.

		Reserves Life Index (years)	
	Q4/2015 Actual Production	Proved	Proved Plus Probable
Oil and NGL (bbl/d)	65,659	9.1	14.1
Natural Gas (mcf/d)	92,708	10.2	14.0
Oil Equivalent (boe/d)	81,110	9.3	14.1

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent qualified reserves evaluators, the efficiency of our capital programs (including future development costs) is summarized in the following table.

	2015	2014	2013	Three-Year Total/Average 2013 - 2015
Capital Expenditures ($ millions)				
Exploration and development	$ 521.0	$ 766.1	$ 550.9	$1,838.0
Acquisitions (net of dispositions)	1.6	2,545.1	(39.1)	2,507.7
Total	$ 522.7	$3,311.2	$ 511.8	$4,345.7
Change in Future Development Costs – Proved ($ millions)				
Exploration and development	$(397.9)	$ (248.5)	$ 300.8	$ (345.6)
Acquisitions (net of dispositions)	6.0	1,312.9	(39.3)	1,279.6
Total	$(391.9)	$1,064.4	$ 261.5	$ 934.0
Change in Future Development Costs – Proved plus Probable ($ millions)				
Exploration and Development	$(399.9)	$ (102.0)	$ 393.7	$ (108.2)
Acquisitions (net of dispositions)	0.5	1,210.5	(39.3)	1,171.7
Total	$(399.4)	$1,108.5	$ 354.4	$1,063.5
Proved Reserves Additions (mboe)				
Exploration and development	21,729	83,515	38,117	143,362
Acquisitions (net of dispositions)	537	68,824	(1,160)	68,201
Total	22,266	152,339	36,957	211,563
Proved plus Probable Reserves Additions (mboe)				
Exploration and development	15,782	33,598	48,936	98,316
Acquisitions (net of dispositions)	126	108,515	(1,540)	107,101
Total	15,908	142,113	47,396	205,417
F&D costs ($/boe)(1)				
Proved	$ 5.67	$ 6.20	$ 22.34	$ 10.41
Proved plus probable	$ 7.68	$ 19.77	$ 19.30	$ 17.59
FD&A costs ($/boe)(2)				
Proved	$ 5.88	$ 28.72	$ 20.92	$ 24.96
Proved plus probable	$ 7.75	$ 31.10	$ 18.28	$ 26.33
Ratios (based on proved plus probable reserves)				
Production replacement(3)	52%	497%	227%	255%
Recycle ratio(4)	2.1x	1.8x	1.7x	1.9x

Notes:

(1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures) divided by reserves additions from exploration and development activity.

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures) divided by total reserves additions.

(3) Production Replacement ratio is calculated as total reserves additions (including acquisitions and divestitures) divided by annual production.

(4) Recycle ratio is calculated as operating netback divided by F&D costs (proved plus probable including future development costs). Operating netback is calculated as revenue (excluding realized hedging gains and losses) minus royalties, production and operating expenses and transportation expenses.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes Sproule and Ryder Scott's estimate of the net present value before income taxes of the future net revenue attributable to our reserves using Sproule's forecast prices and costs (and excluding the impact of any hedging activities). Please note that the data in the table may not add due to rounding.

CANADA

	Summary of Net Present Value of Future Net Revenue As at December 31, 2015 Forecast Prices and Costs Before Income Taxes and Discounted at (%/year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	$ 708,303	$ 611,709	$ 534,278	$ 473,010	$ 424,180
Developed Non-Producing	305,817	210,792	150,901	111,743	85,246
Undeveloped	738,519	537,449	397,466	297,941	225,503
Total Proved	1,752,639	1,359,950	1,082,644	882,694	734,929
Probable	2,621,469	1,437,508	875,496	573,723	395,191
Total Proved Plus Probable	$ 4,374,108	$ 2,797,458	$ 1,958,141	$ 1,456,417	$ 1,130,120

UNITED STATES

Reserves Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	$ 1,696,780	$ 1,283,191	$ 1,027,554	$ 857,701	$ 738,088
Developed Non-Producing					
Undeveloped	2,596,337	1,661,238	1,108,896	761,605	532,125
Total Proved	4,293,117	2,944,429	2,136,450	1,619,306	1,270,213
Probable	830,523	400,056	216,176	127,677	80,458
Total Proved Plus Probable	5,123,640	3,344,485	2,352,627	1,746,984	1,350,670
Possible[1]	3,899,317	2,447,383	1,659,634	1,186,615	880,408
Total Proved Plus Probable Plus Possible[1]	$ 9,022,957	$ 5,791,868	$ 4,012,261	$ 2,933,599	$ 2,231,078

TOTAL

Reserves Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	$ 2,405,083	$ 1,894,899	$ 1,561,832	$ 1,330,711	$ 1,162,267
Developed Non-Producing	305,817	210,792	150,901	111,743	85,246
Undeveloped	3,334,856	2,198,688	1,506,362	1,059,546	757,628
Total Proved	6,045,756	4,304,379	3,219,095	2,502,000	2,005,142
Probable	3,451,992	1,837,564	1,091,673	701,400	475,648
Total Proved Plus Probable	9,497,748	6,141,943	4,310,767	3,203,401	2,480,790
Possible[1][2]	3,899,317	2,447,383	1,659,634	1,186,615	880,408
Total Proved Plus Probable Plus Possible[1][2]	$13,397,065	$ 8,589,326	$ 5,970,402	$ 4,390,016	$ 3,361,198

Notes:

(1) *Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.*

(2) *The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.*

The net present values noted in the table above do not include any value for future net revenue which may ultimately be generated from the contingent resources discussed below.

Sproule Forecast Prices and Costs

The following table summarizes the forecast prices used by Sproule in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2015.

Year	WTI Cushing *US$/bbl*	Canadian Light Sweet *C$/bbl*	Western Canada Select *C$/bbl*	Henry Hub *US$/MMbtu*	AECO-C Spot *C$/MMbtu*	Operating Cost Inflation Rate *%/Yr*	Capital Cost Inflation Rate *%/Yr*	Exchange Rate *$US/$Cdn*
2015 act.	48.80	57.45	46.09	2.63	2.70	1.4	(19.7)	0.783
2016	45.00	55.20	45.26	2.25	2.25	0.0	0.0	0.750
2017	60.00	69.00	57.96	3.00	2.95	0.0	4.0	0.800
2018	70.00	78.43	65.88	3.50	3.42	1.5	4.0	0.830
2019	80.00	89.41	75.11	4.00	3.91	1.5	4.0	0.850
2020	81.20	91.71	77.03	4.25	4.20	1.5	1.5	0.850
2021	82.42	93.08	78.19	4.31	4.28	1.5	1.5	0.850
2022	83.65	94.48	79.36	4.38	4.35	1.5	1.5	0.850
2023	84.91	95.90	80.55	4.44	4.43	1.5	1.5	0.850
2024	86.18	97.34	81.76	4.51	4.51	1.5	1.5	0.850
2025	87.48	98.80	82.99	4.58	4.59	1.5	1.5	0.850
2026	88.79	100.28	84.23	4.65	4.67	1.5	1.5	0.850
Thereafter	Escalation rate of 1.5%							

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below (using forecast prices and costs).

($000s)	CANADA		UNITED STATES		TOTAL	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2016	$ 61,711	$ 85,939	$ 157,342	$ 167,145	$ 219,053	$ 253,084
2017	178,007	225,264	256,592	267,412	434,599	492,676
2018	161,646	359,531	224,399	271,612	386,045	631,143
2019	50,505	236,404	518,791	540,938	569,297	777,342
2020	12,469	113,829	319,128	351,414	331,597	465,243
Remaining	19,602	319,189	26,531	37,251	46,133	356,440
Total (Undiscounted)	$483,940	$1,340,155	$1,502,783	$1,635,772	$1,986,723	$2,975,927

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2015.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	580,616	513,765
British Columbia	660	26
Saskatchewan	139,163	132,990
Total Canada	720,438	646,781
United States		
Texas	10,855	8,409
Total Company	731,294	655,190

We estimate the value of our net undeveloped land holdings at December 31, 2015 to be approximately $110 million. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

Net Asset Value

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before tax, as estimated by the Company's independent reserves engineers, Sproule and Ryder Scott, at year-end, plus the estimated value of our undeveloped acreage, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves evaluators.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of possible reserves or contingent resources. As we execute our capital programs, we expect to convert possible reserves and contingent resources to reserves which could result in an increase in booked proved plus probable reserves.

The following table sets forth our net asset value as at December 31, 2015.

	Net Asset Value Forecast Prices and Costs (before tax) Discounted at				
($ millions, except per share amounts)	0%	5%	10%	15%	20%
Total net present value of proved plus probable reserves (before tax)	$ 9,498	$ 6,142	$ 4,311	$ 3,203	$ 2,481
Undeveloped acreage(1)	110	110	110	110	110
Asset retirement obligations(2)	(425)	(104)	(44)	(30)	(32)
Long–term debt	(1,880)	(1,880)	(1,880)	(1,880)	(1,880)
Net working capital	(170)	(170)	(170)	(170)	(170)
Net Asset Value	$ 7,133	$ 4,098	$ 2,327	$ 1,233	$ 541
Net Asset Value per share(3)	$ 33.87	$ 19.46	$ 11.05	$ 5.85	$ 2.42

Notes:

(1) Undeveloped acreage value generally represents the estimated replacement cost of our undeveloped land.

(2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.

(3) Based on 210.6 million common shares outstanding as at December 31, 2015.

Contingent Resources Assessment

We commissioned Sproule to conduct an evaluation of our contingent resources in the Peace River Area and certain properties in Northeast Alberta. We also commissioned Ryder Scott to conduct an audit of our internal evaluation of our contingent resources in the Eagle Ford Area of Texas. Both assessments were effective December 31, 2015, and were prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and NI 51-101. For additional information on contingent resources, see “Advisory Regarding Oil and Gas Information” below.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The recovery and resource estimates provided herein are estimates. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

The contingent resources described below represent our gross interests and are a best estimate. A “best estimate” is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources identified in the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources herein are presented as deterministic cumulative best estimate volumes.

Our contingent resources fall within the development pending and development unclarified sub-classes, which are defined as follows:

- Development Pending – are economic contingent resources that have a high chance of development. Contingencies are directly influenced by the developer, are actively being pursued and resolution is expected in a reasonable time period.
- Development Unclarified – are contingent resources that have a chance of development which is difficult to assess, and have an economic status which is undetermined. Projects are currently under evaluation and therefore contingencies are not clearly defined. Progress is expected within a reasonable time period.

Development Pending

The following table presents the company gross best estimate of our contingent resources for the assessed properties that fall within the development pending project maturity sub-class, using Sproule’s December 31, 2015 forecast prices and costs.

	Development Pending (Best Estimate)(1)			
	Unrisked (mmboe)	Chance of Development	Risked (mmboe)	Risked NPV Discounted at 10% (before tax) ($MM)
Canada				
Peace River	19	81%	16	$ 90
Northeast Alberta	4	86%	3	$ 10
Total Canada	23		19	$100
United States				
Eagle Ford	74	80%	59	$459
Total Company	96		78	$560

Note:

(1) Numbers may not add due to rounding.

The estimates of risked net present value (“NPV”) of future net revenues of the development pending contingent resources are preliminary assessments and are provided to assist the reader in reaching an opinion on the quality of the resources and likelihood of our proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked NPV of future net revenue will be realized.

The following table summarizes the status of our risked development pending contingent resources.

	Development Pending – Status				
	Product Type	Project Status	Future Development Costs ($ millions)[1]	Timing of First Commercial Production	Recovery Technology
Peace River	Bitumen	Pre-Development	$ 136	2019-2021	Cyclic steam stimulation
Northeast Alberta	Heavy Oil	Pre-Development	$ 54	2021-2027	Horizontal drilling and cold production methods
Eagle Ford	Tight Oil, Shale Gas and NGL	Pre-Development	$1,114	2016-2024	Horizontal multi-stage fracturing and production operations

Note:

(1) Undiscounted and unrisked.

The principal risks that would influence the development of the Peace River and Northeast Alberta development pending contingent resources are: the timing of regulatory approvals to expand the project areas, the results of delineation drilling and seismic activity necessary for project development, the ability of these projects to compete for capital against our other projects, our corporate commitment to the timing of development, and the commodity price levels affecting the economic viability bitumen and heavy oil production in Alberta. The principal risks specific to the development of the Eagle Ford development pending contingent resources are: our reliance on the Operator's commitment of capital and timing to the development, the ability of these projects to compete for capital against our other projects, and the possibility of inter-well communication from infill drilling.

Development Unclarified

Our development unclarified contingent resources are conceptual project scenarios with no specific company defined development plan in the near term. The following table presents the company gross best estimate of our contingent resources for the assessed properties that fall within the development unclarified project maturity sub-classes.

	Development Unclarified (Best Estimate)[1]		
	Unrisked (mmboe)	Chance of Development	Risked (mmboe)
Canada			
Peace River	813	61%	492
Northeast Alberta	141	48%	68
Total Canada	954		560
United States			
Eagle Ford	61	50%	31
Total Company	1,015		590

Note:

(1) Numbers may not add due to rounding.

In addition to the risks identified for the development pending sub-class, the projects in the Peace River and Northeast Alberta development unclarified sub-class are also subject to risks pertaining to commercial productivity of the reservoirs. The geological complexity and variability in these reservoirs may require the implementation of pilot projects to test the viability of steam-assisted gravity drainage and cyclic steam stimulation recovery technologies. The risks outlined for the contingent resources in the Eagle Ford development pending sub-class also apply to the development unclarified sub-class but are greater in magnitude.

Additional disclosures related to our contingent resources will be included in Appendix A to our Annual Information Form for the year ended December 31, 2015.

Advisory Regarding Oil and Gas Information

The reserves information contained in this report has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2015. Listed below are cautionary statements that are specifically required by NI 51-101:

- 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. BOEs 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.
- With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
- This report contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

This report contains estimates as of December 31, 2015 of the volumes of "contingent resources" for our oil resource plays in Peace River and Northeast areas of Alberta and the Sugarkane area in South Texas. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

The recovery and resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

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.

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
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
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

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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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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

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Chad L. Kalmakoff
Vice President, Finance

Gregory A. Sawchenko
Vice President, Land

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

AUDITORS

Deloitte LLP

BANKERS

Bank of Nova Scotia

Alberta Treasury Branches

Bank of America

Bank of Montreal

Barclays Bank plc

Canadian Imperial Bank of Commerce

Caisse Centrale Desjardins

National Bank of Canada

Royal Bank of Canada

Société Générale

The Toronto-Dominion Bank

Union Bank

Wells Fargo Bank

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited

Ryder Scott Company, L.P.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: **BTE**

BAYTEX

ENERGY CORP.

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