Q3 REPORT | TWO THOUSAND FOURTEEN

SUMMARY

- Generated production of 94,093 boe/d (85% oil and NGL) in Q3/2014, an increase of 41% over Q2/2014 and 56% over Q3/2013;
- Delivered funds from operations ("FFO") of $298.0 million ($1.79 per basic share) during Q3/2014, an increase of 80% over Q2/2014 and 49% over Q3/2013;
- Produced approximately 34,000 boe/d in the Eagle Ford in Q3/2014, an increase of approximately 21% from the closing of the acquisition;
- Realized an operating netback (sales price less royalties, production and operating expenses, and transportation expenses) in Q3/2014 of $40.86/boe;
- Maintained a conservative payout ratio, net of Dividend Reinvestment Plan ("DRIP") participation, of 30% (40% before DRIP) in Q3/2014; and
- Divested of our North Dakota assets for after-tax net proceeds of approximately $290 million which were used to repay debt.

	Three Months Ended			Nine Months Ended	
	September 30, 2014	June 30, 2014	September 30, 2013	September 30, 2014	September 30, 2013
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 634,415**	$ 476,404	$ 422,791	**$ 1,496,627**	$ 1,036,747
Funds from operations(1)	**297,964**	165,503	199,318	**634,277**	456,894
Per share – basic	**1.79**	1.22	1.61	**4.44**	3.71
Per share – diluted	**1.78**	1.21	1.59	**4.40**	3.66
Cash dividends declared(2)	**89,771**	75,397	61,354	**228,610**	178,129
Dividends declared per share	**0.72**	0.68	0.66	**2.06**	1.98
Net income	**144,369**	36,799	87,331	**229,009**	133,672
Per share – basic	**0.87**	0.27	0.70	**1.60**	1.08
Per share – diluted	**0.86**	0.27	0.70	**1.59**	1.07
Exploration and development	**230,032**	148,916	121,484	**551,373**	465,840
Acquisitions, net of divestitures	**(341,908)**	2,920,845	2,838	**2,580,818**	(41,340)
Total oil and natural gas capital expenditures	**$ (111,876)**	$ 3,069,761	$ 124,322	**$ 3,132,191**	$ 424,500
Bank loan	**$ 624,067**	$ 952,402	$ 244,651	**$ 624,067**	$ 244,651
Long-term debt	**1,380,811**	1,329,487	454,275	**1,380,811**	454,275
Working capital deficiency	**250,939**	178,517	57,703	**250,939**	57,703
Total monetary debt(3)	**$ 2,255,817**	$ 2,460,406	$ 756,629	**$ 2,255,817**	$ 756,629

	Three Months Ended			Nine Months Ended	
	September 30, 2014	June 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
OPERATING					
Daily production					
Heavy oil (bbl/d)	**45,456**	45,986	44,908	**45,559**	41,664
Light oil and condensate (bbl/d)	**28,124**	9,864	6,670	**14,569**	6,403
NGL (bbl/d)	**6,629**	2,476	1,696	**3,714**	1,760
Total oil and NGL (bbl/d)	**80,209**	58,326	53,274	**63,842**	49,827
Natural gas (mcf/d)	**83,300**	51,645	41,460	**58,766**	41,979
Oil equivalent (boe/d @ 6:1)	**94,093**	66,934	60,184	**73,636**	56,823
Average prices (before hedging)					
WTI oil (US$/bbl)	**97.17**	102.99	105.82	**99.61**	98.15
WCS Heavy Oil (US$/bbl)	**76.99**	82.95	88.34	**78.50**	75.29
Edmonton par oil ($/bbl)	**98.65**	106.68	105.07	**101.83**	95.55
LLS oil (US$/bbl)	**100.87**	105.55	109.92	**103.60**	109.55
BTE heavy oil ($/bbl)	**73.99**	79.26	79.29	**74.84**	66.41
BTE light oil and condensate ($/bbl)	**99.65**	104.16	100.81	**100.19**	92.20
BTE NGL ($/bbl)	**36.77**	38.74	40.71	**40.59**	41.32
BTE total oil and NGL ($/bbl)	**79.91**	81.74	80.75	**78.62**	68.83
BTE natural gas ($/mcf)	**4.43**	4.84	2.72	**4.73**	3.26
BTE oil equivalent ($/boe)	**72.04**	75.06	73.36	**71.97**	62.77
CAD/USD noon rate at period end	**1.1208**	1.0676	1.0285	**1.1208**	1.0285
CAD/USD average rate for period	**1.0893**	1.0894	1.0385	**1.0940**	1.0236
TSX					
Share price (Cdn$)					
High	**49.49**	49.88	44.44	**49.88**	47.60
Low	**41.73**	44.30	37.65	**38.90**	36.37
Close	**42.35**	45.89	42.51	**42.35**	42.51
Volume traded (thousands)	**40,645**	45,952	24,658	**140,378**	82,511
NYSE					
Share price (US$)					
High	**46.46**	46.30	43.08	**46.46**	47.47
Low	**37.54**	40.70	35.72	**35.34**	34.75
Close	**37.86**	42.16	41.27	**37.86**	41.27
Volume traded (thousands)	**5,212**	3,552	3,282	**12,915**	11,414
Common shares outstanding (thousands)	**166,709**	165,421	124,497	**166,709**	124,497

Notes:

(1) *Funds from operations is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define funds from operations as cash flow from operating activities adjusted for finance costs, changes in non-cash operating working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and nine months ended September 30, 2014.*

(2) *Cash dividends declared are net of DRIP participation.*

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

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

(5) *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 average production rate for the second half of 2014 and full-year 2014; our exploration and development capital expenditures for the second half of 2014 and full-year 2014; our Eagle Ford shale play, including our assessment of the performance of wells drilled in the Eagle Ford in 2014, initial production rates from new wells, our expectations that the Eagle Ford assets have the drilling inventory and infrastructure in place that support future growth, the potential to expand our drilling inventory by drilling up to four stacked horizons from a single well pad, the capital efficiency of our Eagle Ford wells relative to other North American projects and the timing of completion of planned maintenance on central processing facilities; our Peace River heavy oil resource play, including our plans to implement a water flood pilot, the timing of commencing water injection and the potential to enhance ultimate recovery from the field; our Lloydminster heavy oil properties, including the potential to improve capital efficiencies through the use of multi-lateral drilling techniques and our plans for an expanded multi-lateral drilling program in 2015; our Gemini steam-assisted gravity drainage project, including our assessment of the performance of the pilot project and our plans to file an application to amend the currently approved project; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate light oil; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate our exposure to heavy oil price differentials by transporting our crude oil to market by railways; our liquidity and financial capacity; the sufficiency of our financial resources to fund our operations; the capital efficiency of our projects relative to other North American projects; our ability to continue to add production at relatively low capital costs per barrel and maintain our productive capacity by reinvesting a portion of our funds from operations; our ability to generate sufficient funds from operations in 2015 under specified pricing assumptions to fund our sustaining capital requirements and cash dividends on our common shares; and our objective, over the long-term, to fund our capital expenditures and cash dividends on our common shares with funds from operations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Although Baytex believes that the expectations and assumptions upon which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Baytex can give no assurance that they will prove to be correct.

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

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

Oil and Gas Information

References herein to initial test production rates, 30-day IP 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. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Non-GAAP Financial Measures

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

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

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

MESSAGE TO SHAREHOLDERS

Operations Review

Production averaged 94,093 boe/d (85% oil and NGL) during Q3/2014, an increase of 41% from Q2/2014 and 56% from Q3/2013, which reflects a strong contribution (and first full quarter) from our Eagle Ford assets and continued strong performance from our Canadian assets. Capital expenditures for exploration and development activities totaled $230.0 million in Q3/2014 and included the drilling of 107 (41.4 net) wells with a 99% success rate.

As previously announced, we divested of our North Dakota Bakken assets on September 24, 2014 for after-tax net proceeds of approximately $290 million. The proceeds were applied against outstanding indebtedness. The North Dakota assets contributed approximately 3,500 boe/d of production in Q3/2014.

We are updating our 2014 guidance to reflect our strong third quarter operating performance. We now expect to generate an average production rate of 91,000 to 92,000 boe/d for the second half of 2014, which at the mid-point reflects an increase of 5% over our previous guidance of 86,000 to 88,000 boe/d. We expect to generate this additional production while maintaining our original capital spending guidance of $440 to $465 million for the second half of 2014. Our full-year 2014 production guidance has also been adjusted upward to 77,000 to 78,000 boe/d (previously 74,000 to 76,000 boe/d) with forecast exploration and development expenditures of $765 to $790 million remaining unchanged.

Wells Drilled – Three Months Ended September 30, 2014

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster	33	13.8	–	–	–	–	4	4.0	1	0.2	38	18.0
Peace River	6	6.0	–	–	–	–	–	–	–	–	6	6.0
	39	**19.8**	**–**	**–**	**–**	**–**	**4**	**4.0**	**1**	**0.2**	**44**	**24.0**
Light oil, NGL and natural gas												
Eagle Ford	60	14.9	–	–	–	–	–	–	–	–	60	14.9
Western Canada	–	–	–	–	–	–	–	–	–	–	–	–
North Dakota	3	2.5	–	–	–	–	–	–	–	–	3	2.5
	63	**17.4**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**63**	**17.4**
Total	**102**	**37.2**	**–**	**–**	**–**	**–**	**4**	**4.0**	**1**	**0.2**	**107**	**41.4**

Wells Drilled – Nine Months Ended September 30, 2014

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster	146	84.9	2	2.0	–	–	17	17.0	3	2.2	168	106.1
Peace River	26	26.0	–	–	–	–	24	24.0	–	–	50	50.0
	172	**110.9**	**2**	**2.0**	**–**	**–**	**41**	**41.0**	**3**	**2.2**	**218**	**156.1**
Light oil, NGL and natural gas												
Eagle Ford	71	17.8	–	–	–	–	–	–	–	–	71	17.8
Western Canada	6	5.7	–	–	2	2.0	–	–	–	–	8	7.7
North Dakota	14	7.2	–	–	–	–	–	–	–	–	14	7.2
	91	**30.7**	**–**	**–**	**2**	**2.0**	**–**	**–**	**–**	**–**	**93**	**32.7**
Total	**263**	**141.6**	**2**	**2.0**	**2**	**2.0**	**41**	**41.0**	**3**	**2.2**	**311**	**188.8**

Eagle Ford Performance

Our Q3/2014 results reflect the first full quarter of operations for our Eagle Ford assets. When we acquired the Eagle Ford assets, the acreage position included 22,200 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. Since that time, we have acquired additional acreage bringing our total land position to approximately 23,000 net acres. At the time of the acquisition, production from the Eagle Ford was approximately 28,000 boe/d. In Q3/2014, production from the Eagle Ford averaged approximately 34,000 boe/d, an increase of approximately 21%. Production from the Eagle Ford represented approximately 36% of our Q3/2014 production.

Drilling results in the Eagle Ford have exceeded our initial expectations with wells drilled in 2014 outperforming the type curves upon which our acquisition evaluation was based. The evaluation was based on 30-day initial production rates of 800 to 1,000 boe/d. Through the first eight months of 2014, a total of 22.3 net wells have been drilled and placed on production for more than 30 days. For these wells, we are seeing an approximate 20% improvement in 30-day initial production rates. This improved performance is driven by a combination of factors, including the drilling of longer horizontal laterals, tighter spacing of fracs and an increased amount of proppant per frac stage. These individual well economics provide some of the highest capital efficiencies in North America.

In Q3/2014, we participated in the drilling of 60 (14.9 net) wells and commenced production from 51 (14.4 net) wells. The capital expenditures for the Eagle Ford assets incurred during the quarter totaled $140.3 million.

We have also identified additional well locations to support future growth. In addition to targeting the Lower Eagle Ford formation, we are now actively delineating the Austin Chalk formation. To-date, we have delineated the Austin Chalk on approximately 50% of our acreage. Furthermore, we are now piloting the drilling of up to four stacked horizons from a single pad, which, if successful, could lead to a further expansion of our drilling inventory.

During the third quarter, two new central processing facilities were commissioned, each capable of processing 20,000 bbl/d of oil and 60 mmcf/d of natural gas. This increases the total number of central processing facilities across our Eagle Ford assets to 15 and has contributed to a debottlenecking of production in the quarter. Planned maintenance on facilities is expected to occur during the fourth quarter.

Canadian Operations

In Canada, our operations and capital program remain on track with our full-year plans. Production in Canada averaged 56,709 boe/d (87% oil and NGL) in Q3/2014, essentially unchanged from Q3/2013.

Production from our Peace River area properties averaged approximately 26,500 boe/d in Q3/2014, essentially unchanged from Q3/2013. In Q3/2014, we drilled six (6.0 net) cold horizontal producers encompassing a total of 81 laterals in the Peace River area. We also received regulatory approval to implement a water flood pilot in the Bluesky reservoir in Harmon Valley. Construction of the required facilities commenced in Q3/2014 and we anticipate that water injection will begin in Q4/2014. This is our first water flood project in the Peace River area, which, if successful, could enhance our ultimate recoveries from the field.

In our Lloydminster heavy oil area, we continue to expand the use of multi-lateral drilling techniques. In Q3/2014, we drilled three (3.0 net) successful horizontal multi-lateral wells (one dual lateral well and two triple lateral wells). Initial results are showing an approximate 20% improvement in capital efficiencies through the use of multi-lateral drilling. We continue to monitor the performance of these wells and are planning for an expanded multi-lateral drilling program in the Lloydminster area for 2015.

At our Gemini steam-assisted gravity drainage (“SAGD”) pilot project, the 600 metre horizontal well pair averaged 850 bbl/d in Q3/2014, with peak oil rates exceeding 1,100 bbl/d. Since acquiring the Gemini acreage in 2013, we have drilled 21 stratigraphic test wells to further delineate our acreage position. At the time of initial acquisition, the Gemini project had regulatory approval for a 10,000 bbl/d SAGD facility. Consistent with our delineation plans, in Q4/2014 we will be filing the required regulatory amendment for our planned 5,000 bbl/d SAGD facility. The amendment will include the additional delineated lands as well as capture various facility modifications. While this regulatory step is necessary to progress the project, a final investment decision is contingent upon a full economic review and the outcome of the front end engineering study which is currently in progress.

Financial Review

We generated FFO of $298.0 million ($1.79 per basic share) during Q3/2014, representing an increase of 80% from Q2/2014 and 49% from Q3/2013. This level of FFO on both an absolute and per-share basis is the highest ever recorded by Baytex and reflects a strong contribution from our Eagle Ford assets and continued strong operational execution in Canada.

The average WTI price for Q3/2014 was US$97.17/bbl, representing a decrease of 6% from Q2/2014 and 8% from Q3/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 21% in Q3/2014, as compared to 19% in Q2/2014 and 17% in Q3/2013. Our realized oil and NGL price of $79.91/bbl in Q3/2014 decreased by 2% from $81.74/bbl in Q2/2014 and 1% from $80.75/bbl in Q3/2013.

Subsequent to quarter-end, WTI has fallen to the US$80.00/bbl level due to lower than expected global demand, the return of Libyan exports and increased crude inventories. Offsetting to a certain degree the decline in WTI has been a strengthened market for WCS heavy oil and a decline in the Canadian dollar relative to the U.S. dollar. The WCS dollar differential for the October and November trade months averaged US$13.74/bbl and US$12.94/bbl, respectively, as compared to US$20.18/bbl in Q3/2014. The improvement in WCS pricing has been driven by increased refinery demand in the U.S. Midwest, a continued increase in crude by rail volumes and, more recently, expanded pipeline shipping capacity. The Canadian dollar has weakened from an average of 1.0893 (C$/US$) in Q3/2014 to its current level of approximately 1.1250 (C$/US$) in response to broad U.S. dollar strength through the wind down of U.S. quantitative easing.

Our Eagle Ford assets contributed positively to our overall operating netback in Q3/2014. Our Canadian operations generated an operating netback of $37.86/boe while the Eagle Ford generated an operating netback of $45.29/boe. On a combined basis (including North Dakota) we generated an operating netback (excluding financial derivatives) of $40.86/boe in Q3/2014. The table below provides a summary of our operating netbacks for the periods noted.

	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013	
($ per boe)	Canada	Eagle Ford	Total	Total	Change
Sales Price	$67.93	$77.19	$72.04	$73.36	(2%)
Less:					
Royalties	13.45	23.03	17.43	15.04	16%
Production and operating expenses	12.70	7.37	10.85	13.09	(17%)
Transportation expenses	3.92	1.50	2.90	3.09	(6%)
Operating netback	$37.86	$45.29	$40.86	$42.14	(3%)

We employ risk mitigation strategies to reduce the volatility in our FFO. For Q4/2014, we have entered into hedges on approximately 51% of our net WTI exposure at a weighted average price of US$96.45/bbl. In addition, we have hedged approximately 36% of our net natural gas price exposure and 34% of our exposure to currency movements between the U.S. and Canadian dollars. For the first half of 2015, we have entered into hedges on approximately 37% of our net WTI exposure at a weighted average price of US$94.79/bbl, and approximately 11% at US$94.23/bbl for the second half of 2015.

As part of our hedging program, we are focusing on opportunities to mitigate the volatility in WCS price differentials by transporting crude oil to higher value markets by rail. Currently, approximately 60% of our heavy oil volumes are delivered to market by rail. Earlier this year, we entered into our first Brent-based fixed differential physical heavy oil sale. This six-month term rail contract runs from October 1, 2014 to March 31, 2015 and is expected to represent approximately 25% of our crude by rail volumes.

Total monetary debt at the end of Q3/2014 is $2.26 billion of which approximately $1.38 billion is comprised of long-term debt with no material repayments required until 2021. With approximately $600 million in undrawn capacity on existing credit facilities of approximately $1.2 billion, we have ample liquidity to allow us to execute our growth and income model.

Current Outlook

We are committed to our growth and income business model and its three fundamental principles: delivering organic production growth, paying a meaningful dividend and maintaining capital discipline. When oil prices fall as they have in the past month, this can put stress on any business model. However, we believe we are well positioned to weather the current downturn. We have some of the strongest capital efficiencies across our portfolio which allows us to add production at relatively low capital costs per barrel and we are now directing over 90% of our capital to three resource plays which have among the highest capital efficiencies in North America. Our strong capital efficiencies benefit us as we require a lower percentage of our FFO to be reinvested to maintain our productive capacity.

While we have not finalized our plans for 2015, we have carried out various sensitivity analyses. A sensitivity analysis using a WTI price of US$80.00/bbl, an exchange rate of 1.12 (C$/US$) and a WCS differential of 18% provides some context to the current commodity price environment. Under these assumptions, we would expect to generate sufficient FFO to fund our sustaining capital requirements and the cash portion of our dividend. Over the long-term, our objective is to fund our capital expenditures and cash dividends with FFO. While this represents just one scenario, in a persistent low commodity price environment, we would initially look to reduce our capital expenditures to achieve this balance.

Conclusion

Our third quarter results reflect a strong contribution from our Eagle Ford assets, which has resulted in record production and funds from operations. Our operating results to-date in the Eagle Ford have exceeded our initial expectations with wells drilled in 2014 outperforming the type curves upon which our acquisition evaluation was based. Reflective of our strong operating results, we are increasing our production guidance for the second half of 2014 by 5% with an unchanged exploration and development capital budget.

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

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
October 30, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and nine months ended September 30, 2014. This information is provided as of October 30, 2014. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The third quarter results have been compared with the corresponding period in 2013. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three and nine months ended September 30, 2014, its audited comparative consolidated financial statements for the years ended December 31, 2013 and 2012, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2013. 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, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

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

Payout Ratio

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

Total Monetary Debt

We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities. See "Liquidity, Capital Resources and Risk Management" for a description of Total Monetary Debt.

Operating Netback

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

THIRD QUARTER HIGHLIGHTS

The third quarter of 2014 includes our first full quarter of results from the Eagle Ford assets that we acquired on June 11, 2014. Our production for the three months ended September 30, 2014 was 94,093 boe/d, significantly higher than any prior period due to the acquisition and continued strong performance from our base Canadian assets. The new Eagle Ford assets added 33,886 boe/d of production and $240.6 million of revenue in the quarter. During the quarter, the price of West Texas Intermediate ("WTI") decreased and the heavy oil differential increased which tempered some of the positive impact of the production increase on revenue. Funds from operations for the third quarter were $298.0 million, bringing total funds from operations for the year to $634.3 million. In late September 2014, we completed the disposition of our assets in North Dakota, which produced approximately 3,500 boe/d in the third quarter of 2014. Proceeds from the disposition of $341.6 million ($289.1 million net of tax) were applied against outstanding indebtedness. We also generated net income of $144.4 million in the third quarter of 2014, up from $87.3 million for the same period last year.

BUSINESS COMBINATION

On June 11, 2014, we acquired all of the ordinary shares of Aurora Oil & Gas Limited ("Aurora") for a total purchase price of approximately $2.8 billion, including the assumption of $955 million of indebtedness and $54.6 million of cash. Aurora's primary asset consisted of 22,200 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate future annual production growth. The acquisition added an estimated 166.6 million boe of proved and probable reserves. In addition, these assets have future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones.

To finance the acquisition of Aurora, we issued 38,433,000 common shares, raising gross proceeds of approximately $1.5 billion. We also negotiated an agreement with a Canadian chartered bank for the provision of new unsecured revolving credit facilities of approximately $1.4 billion (to replace the $850 million revolving credit facilities of Baytex Energy Ltd.) and issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 and US$400 million of 5.625% notes due June 1, 2024. Approximately US$746 million of the proceeds from the issuance of the senior unsecured notes were used to acquire and cancel approximately 98% of the senior debt assumed from Aurora.

The Results of Operations include the Eagle Ford assets from June 11, 2014. Total production from the date of acquisition to September 30, 2014 was 3,673,175 boe (32,796 boe/d), including 33,886 boe/d for the three months ended September 30, 2014 and 13,455 boe/d for the nine months ended September 30, 2014. Revenue for the period since acquisition was $288.1 million, or $78.44/boe, which generated an operating netback for the Eagle Ford assets of $46.60/boe.

RESULTS OF OPERATIONS

The Canadian division includes the heavy oil assets in Peace River and Lloydminster and the conventional oil and natural gas assets in Western Canada. The U.S. division includes the Eagle Ford assets in Texas and the Bakken assets in North Dakota. The Bakken assets were sold on September 24, 2014.

Production

	Three Months Ended September 30					
	2014			2013		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Crude oil (bbl/d)						
Heavy oil[(1)]	45,456	–	45,456	44,908	–	44,908
Light oil and condensate	2,628	25,496	28,124	3,301	3,369	6,670
NGL	1,174	5,455	6,629	1,668	28	1,696
Total crude oil (bbl/d)	49,258	30,951	80,209	49,877	3,397	53,274
Natural gas (mcf/d)	44,703	38,597	83,300	41,270	190	41,460
Total production (boe/d)	56,709	37,384	94,093	56,755	3,429	60,184
Production Mix						
Heavy oil	80%	–%	48%	79%	–%	75%
Light oil and condensate	5%	68%	30%	6%	98%	11%
NGL	2%	15%	7%	3%	1%	3%
Natural gas	13%	17%	15%	12%	1%	11%

(1) Heavy oil sales volumes may differ from reported production volumes due to changes in our heavy oil inventory. For the three months ended September 30, 2014, heavy oil sales volumes were 44 bbl/d higher than production volumes (three months ended September 30, 2013 – 78 bbl/d higher).

	Nine Months Ended September 30					
	2014			2013		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Crude oil (bbl/d)						
Heavy oil[(1)]	45,559	–	45,559	41,664	–	41,664
Light oil and condensate	2,664	11,905	14,569	3,297	3,106	6,403
NGL	1,461	2,253	3,714	1,730	30	1,760
Total crude oil (bbl/d)	49,684	14,158	63,842	46,691	3,136	49,827
Natural gas (mcf/d)	43,033	15,733	58,766	41,794	185	41,979
Total production (boe/d)	56,856	16,780	73,636	53,657	3,167	56,823
Production Mix						
Heavy oil	79%	–%	61%	78%	–%	74%
Light oil and condensate	5%	71%	21%	6%	99%	11%
NGL	3%	13%	5%	3%	1%	3%
Natural gas	13%	16%	13%	13%	–%	12%

(1) Heavy oil sales volumes may differ from reported production volumes due to changes in our heavy oil inventory. For the nine months ended September 30, 2014, heavy oil sales volumes were 82 bbl/d higher than production volumes (nine months ended September 30, 2013 – 91 bbl/d higher).

Total production for the three months ended September 30, 2014 of 94,093 boe/d increased by 56%, or 33,909 boe/d, from the three months ended September 30, 2013, primarily due to the acquisition. Canadian heavy oil and natural gas production increased due to successful development activities in the Peace River and Pembina areas, however heavy oil production was negatively impacted in the third quarter due to temporary pipeline and rail issues. Light oil and natural gas liquids ("NGL") production decreased due to natural declines. Subsequent to the acquisition in June, the Eagle Ford properties have contributed 22,313 bbl/d of light oil and condensate, 5,310 bbl/d of NGL and 37,578 mcf/d of natural gas for a total of 33,886 boe/d for the three months ended September 30, 2014.

Total production for the nine months ended September 30, 2014 of 73,636 boe/d increased by 30%, or 16,813 boe/d, compared to the same period in 2013, primarily due to the acquisition. Canadian production increased primarily due to successful heavy oil development in Peace River. Subsequent to the acquisition in June, the Eagle Ford properties contributed 8,890 bbl/d of light oil and condensate, 2,096 bbl/d of NGL and 14,812 mcf/d of natural gas for a total of 13,455 boe/d for the nine months ended September 30, 2014.

Commodity Prices

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

Crude Oil

For the three months ended September 30, 2014, the WTI oil prompt averaged US$97.17/bbl, an 8% decrease from the average WTI price of US$105.82/bbl in the third quarter of 2013. During the three months ended September 30, 2014, crude oil prices posted steady declines from their June highs. Factors contributing to declining prices included lower than expected global summer demand, the return of Libyan exports and increased crude inventories. For the nine months ended September 30, 2014, the WTI oil prompt averaged US$99.61/bbl, a 1% increase from the average WTI price of US$98.15/bbl during the same period in 2013. In the first nine months of 2014, WTI prices traded as high as US$107.73/bbl in June on heightened geopolitical risk and bullish sentiment surrounding the summer refining season, but have since fallen to multi-year lows due to the aforementioned factors.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 21% for the three months ended September 30, 2014, as compared to 17% for the same period in 2013. WCS differentials increased due to lower refining runs as a result of lower refinery margins as compared to the same period of 2013. For the nine months ended September 30, 2014, the WCS heavy oil differential averaged 21%, as compared to 23% in the first nine months of 2013. The current year has seen less volatility in the differential as compared to previous years due to the conversion of BP Whiting's refinery to run heavy oil, more rail transportation options and, more recently, expanded pipeline shipping capacity out of Western Canada.

Natural Gas

For the three months ended September 30, 2014, the AECO natural gas prices averaged $4.22/mcf, a 50% increase compared to $2.82/mcf in the same period in 2013. The increase in natural gas prices was supported by storage restocking after a prolonged and colder than normal 2013-2014 winter despite lower than expected cooling demand during the summer. In the first nine months of 2014, natural gas prices also benefited from a weaker Canadian dollar and a colder than normal winter, as compared to the same period in 2013.

The following table compares selected benchmark prices and our average realized selling prices for the current quarter and year to date against the same periods last year.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	Change	**2014**	2013	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**$ 97.17**	$ 105.82	(8%)	**$ 99.61**	$ 98.15	1%
WCS heavy oil (US$/bbl)[2]	**$ 76.99**	$ 88.34	(13%)	**$ 78.50**	$ 75.29	4%
Heavy oil differential[3]	**(21%)**	(17%)		**(21%)**	(23%)	
LLS oil (US$/bbl)[4]	**$ 100.87**	$ 109.92	(8%)	**$ 103.60**	$ 109.55	(5%)
CAD/USD average exchange rate	**1.0893**	1.0385	5%	**1.0940**	1.0236	7%
Edmonton par oil ($/bbl)	**$ 98.65**	$ 105.07	(6%)	**$ 101.83**	$ 95.55	7%
AECO natural gas price ($/mcf)[5]	**$ 4.22**	$ 2.82	50%	**$ 4.55**	$ 3.12	46%
Average Sales Prices[7]						
Canadian heavy oil ($/bbl)[6]	**$ 73.99**	$ 79.29	(7%)	**$ 74.84**	$ 66.41	13%
Light oil and condensate ($/bbl)						
Canada	**$ 92.92**	$ 100.98	(8%)	**$ 95.91**	$ 90.50	6%
U.S.	**100.35**	100.65	–%	**101.15**	94.00	8%
Total	**$ 99.65**	$ 100.81	(1%)	**$ 100.19**	$ 92.20	9%
NGL ($/bbl)						
Canada	**$ 48.83**	$ 40.56	20%	**$ 49.36**	$ 41.23	20%
U.S.	**34.18**	49.81	(31%)	**34.89**	46.61	(25%)
Total	**$ 36.77**	$ 40.71	(10%)	**$ 40.59**	$ 41.32	(2%)
Total oil and NGL ($/bbl)						
Canada	**$ 74.40**	$ 79.43	(6%)	**$ 75.22**	$ 67.17	12%
U.S.	**88.68**	100.24	(12%)	**90.61**	93.55	(3%)
Total	**$ 79.91**	$ 80.75	(1%)	**$ 78.62**	$ 68.83	14%
Natural gas ($/mcf)						
Canada	**$ 4.19**	$ 2.72	54%	**$ 4.69**	$ 3.25	44%
U.S.	**4.71**	4.15	13%	**4.85**	4.26	14%
Total	**$ 4.43**	$ 2.72	63%	**$ 4.73**	$ 3.26	45%
Summary						
Weighted average ($/boe)[7]						
Canada	**$ 67.93**	$ 71.78	(5%)	**$ 69.29**	$ 61.00	14%
U.S.	**78.28**	99.54	(21%)	**80.99**	92.89	(13%)
Total	**$ 72.04**	$ 73.36	(2%)	**$ 71.97**	$ 62.77	15%

(1) WTI refers to the arithmetic average based on NYMEX prompt month WTI.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) Heavy oil differential refers to the WCS discount to WTI on a monthly weighted average basis.
(4) Louisiana Light Sweet ("LLS") refers to the monthly arithmetic average for Argus LLS front month.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter.
(6) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(7) 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.

Average Realized Sales Prices

Our realized heavy oil price during the third quarter of 2014 was $73.99/bbl, or 88% of WCS, compared to $79.29/bbl, or 86% of WCS, in the third quarter of 2013. The realized price during the third quarter of 2014 decreased by 7% due to a decrease in WTI coupled with an increase in the WCS differential partially offset by the weakening of the Canadian dollar compared to the third quarter of 2013. During the third quarter of 2014, our average sales price for Canada light oil and condensate was $92.92/bbl, down 8% from $100.98/bbl in the third quarter of 2013, which is in line with the decrease in the Edmonton par oil benchmark price over the same period. In the U.S., our average sales during the third quarter of 2014 for light oil and condensate was $100.35/bbl, down slightly from $100.65/bbl in the third quarter of 2013. The decrease is mainly due to the decline of crude oil prices partially offset by higher pricing received for Eagle Ford production as compared to North Dakota production. Our realized natural gas price for the three months ended September 30, 2014 was $4.43/mcf, up from $2.72/mcf in the second quarter of 2013. The increase is in line with the increase in the AECO benchmark applicable to the Canadian production and consistent with expected prices for the Eagle Ford production over the same period.

Our realized heavy oil price for the nine months ended September 30, 2014 was $74.84/bbl, or 87% of WCS, compared to $66.41/bbl, or 86% of WCS, in the first nine months of 2013. The 13% increase is due to the weakening of the Canadian dollar against the U.S. dollar compared to the same period in 2013, an increase in the benchmark prices and increased utilization of rail. During the first nine months of 2014, our average sales price for light oil and condensate was $95.91/bbl, up 6% from $90.50/bbl in the first nine months of 2013, consistent with the increase in the Edmonton par oil benchmark price over the same period. Light oil and condensate pricing for the U.S. for the first nine months of 2014 was $101.15/bbl, up 8% from $94.00/bbl for the same period of 2013 due to higher pricing received for Eagle Ford production as compared to North Dakota production. Our realized natural gas price for the nine months ended September 30, 2014 was $4.73/mcf, up from $3.26/mcf in the third quarter of 2013, largely in line with increase in the AECO benchmark and the U.S. natural gas benchmarks.

Gross Revenues

	Three Months Ended September 30					
	2014			2013		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 309,719	$ –	$ 309,719	$ 328,145	$ –	$ 328,145
Light oil and condensate	22,466	235,377	257,843	30,658	31,200	61,858
NGL	5,272	17,150	22,422	6,226	127	6,353
Total oil revenue	337,457	252,527	589,984	365,029	31,327	396,356
Natural gas revenue	17,249	16,709	33,958	10,308	73	10,381
Total oil and natural gas revenue	354,706	269,236	623,942	375,337	31,400	406,737
Other income	–	(2)	(2)	–	–	–
Heavy oil blending revenue	10,475	–	10,475	16,054	–	16,054
Total petroleum and natural gas revenues	$ 365,181	$ 269,234	$ 634,415	$ 391,391	$ 31,400	$ 422,791

	Nine Months Ended September 30					
	2014			2013		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 932,448	$ –	$ 932,448	$ 756,962	$ –	$ 756,962
Light oil and condensate	69,747	328,762	398,509	81,439	79,713	161,152
NGL	19,690	21,461	41,151	19,471	382	19,853
Total oil revenue	1,021,885	350,223	1,372,108	857,872	80,095	937,967
Natural gas revenue	55,104	20,812	75,916	37,128	216	37,344
Total oil and natural gas revenue	1,076,989	371,035	1,448,024	895,000	80,311	975,311
Other income	–	413	413	–	–	–
Heavy oil blending revenue	48,190	–	48,190	61,436	–	61,436
Total petroleum and natural gas revenues	$1,125,179	$ 371,448	$1,496,627	$ 956,436	$ 80,311	$1,036,747

Total petroleum and natural gas revenues for the three months ended September 30, 2014 of $634.4 million increased $211.6 million from the same period in 2013. In Canada, petroleum and natural gas revenues for the three months ended September 30, 2014 totaled $365.2 million which decreased $26.2 million compared to the same period of 2013 due to lower crude oil prices. In the U.S., the Eagle Ford properties contributed $240.6 million of revenue for the three months ended September 30, 2014 which accounted for the majority of the increase compared to 2013.

Total petroleum and natural gas revenues for the nine months ended September 30, 2014 of $1,496.6 million increased $459.9 million from the same period in 2013 largely due to the revenue from the Eagle Ford assets. In

Canada, petroleum and natural gas revenues for the nine months ended September 30, 2014 totaled $1,125.2 million which increased $168.7 million compared to the same period of 2013 due to both higher production volumes and higher realized prices. Petroleum and natural gas revenues in the U.S. increased over the prior year primarily due to the Eagle Ford acquisition which contributed $288.1 million since the date of acquisition to September 30, 2014.

Heavy oil blending revenue was down for the three and nine months ended September 30, 2014 compared to the same periods in 2013 due an increase in volumes of heavy oil being transported by rail. Unlike transportation through oil pipelines, transportation of heavy oil by rail does not require blending diluent.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on netback less capital investment and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons including the commodity produced, royalty contract, commodity price level, royalty incentives and the area or jurisdiction. The following tables summarize our royalties and royalty rates for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30					
	2014			2013		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 70,231	$ 80,691	$ 150,922	$ 72,761	$ 10,635	$ 83,396
Average royalty rate(1)	19.8%	30.0%	24.2%	19.4%	33.9%	20.5%
Royalty rate per boe	$ 13.45	$ 23.46	$ 17.43	$ 13.92	$ 33.71	$ 15.04

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

	Nine Months Ended September 30					
	2014			2013		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 225,458	$ 112,625	$ 338,083	$ 159,171	$ 31,513	$ 190,684
Average royalty rate(1)	20.9%	30.4%	23.3%	17.8%	39.2%	19.6%
Royalty rate per boe	$ 14.50	$ 24.59	$ 16.80	$ 10.85	$ 36.45	$ 12.27

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

Total royalties for the three months ended September 30, 2014 of $150.9 million increased $67.5 million from the three months ended September 30, 2013 primarily due to Eagle Ford royalties of $71.8 million for the three months ended September 30, 2014.

The royalty rate of 19.8% in Canada for the three months ended September 30, 2014 increased from 19.4% over the same period in the prior year due to increased production on certain lands in Peace River with higher applicable rates. This increase was partially mitigated by royalty audits resolved in our favour during the quarter which amounted to $4.3 million. The U.S. royalty rate of 30.0% for the three months ended September 30, 2014 primarily reflects the royalty rate associated with the Eagle Ford properties which averaged approximately 29.5% during the quarter. The higher U.S. royalty rate of 33.9% experienced in 2013 mainly related to carry obligations associated with our North Dakota properties.

Total royalties for the nine months ended September 30, 2014 of $338.1 million increased $147.4 million from the same period in 2013. Overall, royalties have increased to 23.3% for the nine months ended September 30, 2014 compared to the same period during 2013 mainly due to the Eagle Ford properties which carry higher royalty rates. The royalty rate of 20.9% in Canada for the nine months ended September 30, 2014 increased from 17.8% over the same period in 2013 largely due to higher royalty rates on certain lands in Peace River. The higher U.S. royalty rate for the nine months ended September 30, 2013 of 39.2% was due to carry obligations associated with our North Dakota properties.

Production and Operating Expenses

	Three Months Ended September 30					
	2014			2013		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Production and operating expenses	$ 66,311	$ 27,626	$ 93,937	$ 66,501	$ 6,064	$ 72,565
Production and operating expenses per boe	$ 12.70	$ 8.03	$ 10.85	$ 12.72	$ 19.22	$ 13.09

	Nine Months Ended September 30					
	2014			2013		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Production and operating expenses	$ 198,867	$ 39,248	$ 238,115	$ 191,142	$ 15,638	$ 206,780
Production and operating expenses per boe	$ 12.79	$ 8.57	$ 11.83	$ 13.03	$ 18.09	$ 13.31

Production and operating expenses for the three months ended September 30, 2014 of $93.9 million increased $21.4 million compared to the same period in 2013 primarily due to the inclusion of $23.0 million of expenses related to the Eagle Ford properties. Production and operating expenses on a per boe basis decreased by $2.24/boe from the third quarter of 2013 to $10.85/boe in the current period as the Eagle Ford properties had lower average production and operating expenses of $7.37/boe. Canadian production and operating expenses per boe were consistent year over year.

Production and operating expenses for the nine months ended September 30, 2014 of $238.1 million increased $31.3 million compared to the same period in 2013 primarily due to the inclusion of the Eagle Ford properties which contributed $25.6 million to the overall increase. Production and operating expenses in Canada of $198.9 million increased for the nine months ended September 30, 2014 from $191.1 million in the same period in 2013 due to higher production volumes. Canadian production and operating expenses per boe decreased to $12.79/boe for the first nine months of 2014 from $13.03/boe in the same period last year primarily due to lower costs associated with repair and maintenance and fluid hauling in the current period and the impact of severe weather conditions in Saskatchewan in the first half of 2013. U.S. production and operating expenses per boe declined by $9.52/boe to $8.57/boe due to the inclusion of the Eagle Ford properties in 2014 and the impact of severe weather which increased costs during 2013.

Transportation and Blending Expenses

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

The following tables compare our blending and transportation expenses for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30					
	2014			2013		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Blending expenses	$ 10,475	$ –	$ 10,475	$ 16,054	$ –	$ 16,054
Transportation expenses	20,456	4,688	25,144	17,124	–	17,124
Total transportation and blending expenses	$ 30,931	$ 4,688	$ 35,619	$ 33,178	$ –	$ 33,178
Transportation expense per boe(1)	$ 3.92	$ 1.36	$ 2.90	$ 3.27	$ –	$ 3.09

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

	Nine Months Ended September 30					
	2014			2013		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Blending expenses	$ 48,191	$ –	$ 48,191	$ 61,436	$ –	$ 61,436
Transportation expenses	66,228	5,840	72,068	59,318	–	59,318
Total transportation and blending expenses	$ 114,419	$ 5,840	$ 120,259	$ 120,754	$ –	$ 120,754
Transportation expense per boe(1)	$ 4.26	$ 1.27	$ 3.58	$ 4.04	$ –	$ 3.82

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

Blending expenses for the three and nine months ended September 30, 2014 decreased compared to the same periods in 2013 due to lower volumes of condensate being required for blending due to increased volumes being shipped by rail.

Transportation expenses for the three and nine months ended September 30, 2014 totaled $25.1 million and $72.1 million, respectively, and increased $8.0 million and $12.8 million, respectively, compared to the same periods in 2013. The increases are primarily due the inclusion of expenses related to the Eagle Ford properties which accounted for $4.7 million and $5.8 million of the increases, respectively, for the three and nine months ended September 30, 2014 combined with the reversal of a $4.0 million provision during 2013 in Canada which reduced 2013 costs.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize a series of financial derivative contracts which are intended to reduce some of the volatility in our operating cash flow. Financial derivatives are managed corporately and are not allocated between divisions. The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	2014	2013	Change	2014	2013	Change
Realized gain (loss) on financial derivatives[1]						
Crude oil	$ (2,811)	$ (16,713)	$ 13,902	$ (13,252)	$ (1,104)	$ (12,148)
Natural gas	45	744	(699)	(1,771)	823	(2,594)
Foreign currency	(1,281)	27	(1,308)	(4,547)	840	(5,387)
Interest	(4,109)	(3,776)	(333)	(8,130)	(7,381)	(749)
Total	$ (8,156)	$ (19,718)	$ 11,562	$ (27,700)	$ (6,822)	$ (20,878)
Unrealized gain (loss) on financial derivatives[2]						
Crude oil	$ 100,098	$ (10,463)	$ 110,561	$ 57,752	$ (15,537)	$ 73,289
Natural gas	2,528	153	2,375	287	803	(516)
Foreign currency	(10,295)	18,612	(28,907)	(4,177)	(4,095)	(82)
Interest[3]	6,357	(7,649)	14,006	22,325	7,136	15,189
Total	$ 98,688	$ 653	$ 98,035	$ 76,187	$ (11,693)	$ 87,880
Total gain (loss) on financial derivatives						
Crude oil	$ 97,287	$ (27,176)	$ 124,463	$ 44,500	$ (16,641)	$ 61,141
Natural gas	2,573	897	1,676	(1,484)	1,626	(3,110)
Foreign currency	(11,576)	18,639	(30,215)	(8,724)	(3,255)	(5,469)
Interest[3]	2,248	(11,425)	13,673	14,195	(245)	14,440
Total	$ 90,532	$ (19,065)	$ 109,597	$ 48,487	$ (18,515)	$ 67,002

(1) Realized gain (loss) on financial derivatives represents actual cash settlement or receipts for the financial derivatives.

(2) Unrealized gain (loss) on financial derivatives represents the change in fair value of the financial derivatives during the period.

(3) Unrealized gain (loss) on interest rate derivatives includes the change in fair value of the call options embedded in our senior unsecured notes.

Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price on the date the contract matures. As the forward markets for commodities and currencies fluctuate and as new contracts are executed, changes in the fair value are reported as unrealized gains or losses in the period. Contracts in place at the beginning of the period which settle during the period will give rise to the reversal of the unrealized gain or loss recorded at the beginning of the period.

The realized loss of $8.2 million for the three months ended September 30, 2014 on derivative contracts is mainly due to crude oil prices rising to levels above our fixed price contracts, the settlement of our remaining out-of-money interest rate swaps as well as the weakening Canadian dollar against the U.S. dollar at September 30, 2014 over the period. The unrealized mark-to-market gain of $98.7 million for the three months ended September 30, 2014 mainly relates to lower forward crude oil prices at September 30, 2014 compared to prices set in our fixed price contracts, partially offset by the weakening Canadian dollar against the U.S. dollar, as compared to June 30, 2014

The realized loss of $27.7 million for the nine months ended September 30, 2014 on derivative contracts relates mainly to crude oil prices rising to levels above our fixed price contracts, the settlement of our out-of-money interest rate swaps as well as the weakening Canadian dollar against the U.S. dollar at September 30, 2014 over the period. The unrealized mark-to-market gain of $76.2 million for the nine months ended September 30, 2014 is mainly due to lower forward commodity prices at September 30, 2014 compared to prices set in our fixed price contracts, the fair value gain of $14.4 million on the call options embedded in our senior unsecured notes and the settlement of previously recorded unrealized losses on interest rate contracts, partially offset by the weakening Canadian dollar against the U.S. dollar at September 30, 2014 compared to December 31, 2014.

A summary of the financial derivative contracts in place as at September 30, 2014 and the accounting treatment thereof are disclosed in note 19 to the consolidated financial statements.

Operating Netback

	Three Months Ended September 30					
	2014			2013		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	56,753	37,384	94,137	56,834	3,428	60,262
Operating netback[(1)]:						
Sales price	$ 67.93	$ 78.28	$ 72.04	$ 71.78	$ 99.54	$ 73.36
Less:						
Royalties	13.45	23.46	17.43	13.92	33.72	15.04
Production and operating expenses	12.70	8.03	10.85	12.72	19.22	13.09
Transportation expenses	3.92	1.36	2.90	3.27	–	3.09
Operating netback before financial derivatives	$ 37.86	$ 45.43	$ 40.86	$ 41.87	$ 46.60	$ 42.14
Financial derivatives (loss)[(2)]	–	–	(0.47)	–	–	(2.88)
Operating netback after financial derivatives	$ 37.86	$ 45.43	$ 40.39	$ 41.87	$ 46.60	$ 39.26

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

(2) Financial derivatives reflect realized losses on commodity related contracts only and exclude the impact of interest rate swaps.

	Nine Months Ended September 30					
	2014			2013		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	56,938	16,780	73,718	53,747	3,167	56,914
Operating netback[(1)]:						
Sales price	$ 69.29	$ 80.99	$ 71.97	$ 61.00	$ 92.89	$ 62.77
Less:						
Royalties	14.50	24.59	16.80	10.85	36.45	12.27
Production and operating expenses	12.79	8.57	11.83	13.03	18.09	13.31
Transportation expenses	4.26	1.27	3.58	4.04	–	3.82
Operating netback before financial derivatives	$ 37.74	$ 46.56	$ 39.76	$ 33.08	$ 38.35	$ 33.37
Financial derivatives (loss) gain[(2)]	–	–	(0.97)	–	–	0.04
Operating netback after financial derivatives	$ 37.74	$ 46.56	$ 38.79	$ 33.08	$ 38.35	$ 33.41

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

(2) Financial derivatives reflect realized gains (losses) on commodity related contracts only and exclude the impact of interest rate swaps.

Evaluation and Exploration Expense

Evaluation and exploration expense includes the write-off of undeveloped lands and assets and will vary period to period depending on the expiry of leases and our assessment of undeveloped land.

Evaluation and exploration expense decreased to $1.6 million for the three months ended September 30, 2014 from $2.2 million for the same period in 2013 due to a decrease in the expiration of undeveloped land leases.

Evaluation and exploration expense increased to $16.1 million for the nine months ended September 30, 2014 from $7.7 million for the same period in 2013 due to both an increase in the expiration of undeveloped land leases and the write-off of evaluation and exploration assets that will not be developed. Approximately $6.0 million of the expense related to expiring leases in North Dakota which we sold during the third quarter of 2014.

Depletion and Depreciation

	Three Months Ended September 30					
	2014			2013		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation(1)	**$ 78,573**	**$ 92,582**	**$ 172,024**	$ 67,938	$ 5,570	$ 74,397
Depletion and depreciation per boe	**$ 15.05**	**$ 26.92**	**$ 19.86**	$ 12.99	$ 17.66	$ 13.43

(1) Total includes corporate depreciation.

	Nine Months Ended September 30					
	2014			2013		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation(1)	**$ 237,029**	**$ 121,048**	**$ 360,208**	$ 222,700	$ 14,873	$ 239,507
Depletion and depreciation per boe	**$ 15.25**	**$ 26.42**	**$ 17.90**	$ 15.18	$ 17.20	$ 15.41

(1) Total includes corporate depreciation.

Depletion and depreciation expense totaled $172.0 million and $360.2 million for the three and nine months ended September 30, 2014, respectively, as compared to $74.4 million and $239.5 million in the same periods of 2013. The depletion rate per boe for the three and nine months ended September 30, 2014 increased to $19.86/boe and $17.90/boe, respectively, from $13.43/boe and $15.41/boe, respectively, for the comparative periods of 2013, mainly due to the acquisition of the Eagle Ford assets and the full inclusion of the fair value attributed to oil and gas properties in the depletable pool.

General and Administrative Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2014**	2013	Change	**2014**	2013	Change
General and administrative expenses	**$ 16,770**	$ 10,970	53%	**$ 42,978**	$ 33,060	30%
General and administrative expenses per boe	**$ 1.94**	$ 1.98	(2%)	**$ 2.14**	$ 2.13	–%

General and administrative expenses for the three and nine months ended September 30, 2014 increased compared to the same periods of 2013 due to higher salaries and increased head count. Overall we expect our general and administrative expenses per boe to decrease as a result of the Eagle Ford acquisition as we are able to leverage our existing structure to support the acquired operations.

Acquisition-related Costs

During the nine months ended September 30, 2014, acquisition-related costs for the Aurora acquisition were $37.0 million, which included legal, regulatory and advisory fees along with premiums paid on foreign currency hedges.

Gain on Divestiture of Oil and Gas Properties

For the three and nine months ended September 30, 2014 the gain on divestiture of oil and gas properties totaled $26.8 million and $45.6 million, respectively. In the third quarter of 2014 we disposed of our interests located in North Dakota for net proceeds of $341.6 million resulting in a $11.4 million gain before income tax. On the disposition of the North Dakota assets, accumulated other comprehensive income of $15.5 million was also reclassified to gain on divestiture of oil and gas properties. In the second quarter of 2014, we completed a swap of assets, exiting mature properties in Saskatchewan and acquiring additional properties in Peace River area, resulting in a gain on divestiture of oil and gas properties of $18.7 million.

Share-based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan and the Share Rights Plan is recognized in income over the vesting period of the share awards or share rights with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards or exercise of share rights 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 $6.9 million and $22.9 million for the three and nine months ended September 30, 2013, respectively, from $8.6 million and $27.5 million in the three and nine months ended September 30, 2013, respectively. This decrease is primarily due to an increase in actual forfeitures resulting from the closure of our Denver office following the sale of the North Dakota assets combined with a higher estimated future forfeiture rate and a lower estimated payout multiplier for performance awards during 2014 compared to 2013.

Financing Costs

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

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for %)	**2014**	2013	Change	**2014**	2013	Change
Bank loan and other	**$ 8,919**	$ 2,884	209%	**$ 16,332**	$ 7,364	122%
Long-term debt	**20,352**	7,755	162%	**39,547**	23,149	71%
Accretion on asset retirement obligations	**1,786**	1,817	(2%)	**5,307**	5,167	3%
Debt financing costs	**255**	22	1059%	**312**	2,178	(86%)
Financing costs	**$ 31,312**	$ 12,478	151%	**$ 61,498**	$ 37,858	62%

The increases in financing costs for the three and nine months ended September 30, 2014 were primarily due to higher outstanding debt levels compared to the same periods in 2013. Debt levels increased primarily as a result of the acquisition of the Eagle Ford assets.

Foreign Exchange

Unrealized foreign exchange gains and losses are due to translation of the U.S. dollar denominated long-term debt and bank loans caused by the movement of the Canadian dollar against the U.S. dollar during the period. Realized foreign exchange gains and losses are due to our day-to-day U.S. dollar denominated transactions.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for exchange rates)	**2014**	2013	Change	**2014**	2013	Change
Unrealized foreign exchange loss (gain)	**$ 54,937**	$ (4,030)	$ 58,967	**$ 40,014**	$ 4,706	$ 35,308
Realized foreign exchange loss (gain)	**2,109**	(28)	2,137	**3,095**	(3,629)	6,724
Foreign exchange loss (gain)	**$ 57,046**	$ (4,058)	$ 61,104	**$ 43,109**	$ 1,077	$ 42,032
CAD/USD exchange rates:						
At beginning of period	**1.0676**	1.0512		**1.0636**	0.9949	
At end of period	**1.1208**	1.0285		**1.1208**	1.0285	

The foreign exchange losses of $57.0 million and $43.1 million for the three and nine months ended September 30, 2014, respectively, were primarily due to the weaker Canadian dollar against the U.S. dollar upon translation of our U.S. dollar denominated long-term debt and bank loan.

Income Taxes

For the three months ended September 30, 2014, total income tax expense was $41.3 million, an increase of $18.5 million over the same period of 2013, and was comprised of $52.5 million of current income tax expense (three months ended September 30, 2013 – $6.8 million recovery) and $11.2 million of deferred income tax recovery (three months ended September 30, 2013 – $29.6 million expense).

For the nine months ended September 30, 2014, total income tax expense was $81.4 million, an increase of $40.8 million over the same period of 2013), and was comprised of $52.5 million of current income tax expense (nine months ended September 30, 2013 – $6.8 million recovery) and $28.9 million of deferred income tax expense (nine months ended September 30, 2013 – $47.4 million)

The gain on disposition of the North Dakota assets resulted in current income tax expense of $52.5 million and a deferred income tax recovery of $52.4 million.

The decrease in deferred tax expense for both the three and nine months ended September 30, 2014 relates to the realization of current income taxes on the disposition of North Dakota assets, partially offset by the increase in unrealized financial derivative gains, net of unrealized foreign exchange losses and an increase in tax pool claims used to shelter income generated by higher operating netbacks.

Net Income

Net income for the three months ended September 30, 2014 totaled $144.4 million compared to $87.3 million for the same period in 2013. The increase was due to higher operating netbacks, financial derivative gains and gains on divestitures of oil and gas properties in the current quarter, partially offset by foreign exchange losses and higher depletion expense, financing costs and income taxes.

Net income for the nine months ended September 30, 2014 totaled $229.0 million compared to $133.7 million for the same period in 2013. The increase was due to higher operating netbacks, financial derivative gains and gains on divestitures of oil and gas properties, partially offset by higher foreign exchange losses, costs incurred related to the acquisition of Aurora and higher depletion expense, financing costs and income taxes.

Other Comprehensive Income

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. operations not recognized in profit or loss. The $155.5 million and $108.4 million foreign currency translation gain for the three and nine months ended September 30, 2014, respectively, is primarily due to the weakening of the Canadian dollar against the U.S. dollar at September 30, 2014 compared to the exchange rate on June 30, 2014, June 11, 2014 (being the closing date of the acquisition of Aurora), and December 31, 2013, respectively. Other comprehensive income is higher in 2014 than in 2013 as the carrying value of U.S. operations is significantly higher in the current year as a result of the Aurora acquisition.

Capital Expenditures

Capital expenditures for the three and nine months ended September 30, 2014 and 2013 are summarized as follows:

	Three Months Ended September 30					
	2014			2013		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	$ 76,621	$ 153,411	$ 230,032	$ 109,297	$ 12,187	$ 121,484
Acquisitions, net of divestitures	(388)	(341,520)	(341,908)	3,419	(581)	2,838
Other plant and equipment, net(1)	–	–	1,843	–	–	12
Total capital expenditures(1)	$ 76,233	$ (188,109)	$ (110,033)	$ 112,716	$ 11,606	$ 124,334

(1) Total includes corporate capital expenditures.

	Nine Months Ended September 30					
	2014			2013		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	$ 328,994	$ 222,379	$ 551,373	$ 399,169	$ 66,671	$ 465,840
Acquisitions, net of divestitures	8,349	2,572,470	2,580,819	(42,311)	971	(41,340)
Other plant and equipment, net(1)	–	–	6,704	–	–	4,732
Total capital expenditures(1)	$ 337,343	$ 2,794,849	$ 3,138,896	$ 356,858	$ 67,642	$ 429,232

(1) Total includes corporate capital expenditures.

During the three months ended September 30, 2014, exploration and development expenditures of $230.0 million increased $108.5 million from the same period in 2013. The increase is mainly due to higher activity associated with the Eagle Ford acquisition. In the third quarter of 2014, we drilled 41.4 net wells (24.0 net in Canada, 14.9 net in the Eagle Ford and 2.5 net in North Dakota) compared to 58.3 net wells (57.0 net in Canada and 1.3 net in North Dakota) in the three months ended September 30, 2013.

During the nine months ended September 30, 2014, exploration and development expenditures of $551.4 million increased $85.5 million from the same period in 2013. The increase is primarily due to higher activity levels associated with the Eagle Ford acquisition. In the first nine months of 2014, we drilled 188.8 net wells (163.8 net in Canada, 17.8 net in the Eagle Ford and 7.2 net in North Dakota) compared to 193.9 net wells (185.3 net in Canada and 8.6 net in North Dakota) in the nine months ended September 30, 2013.

In 2014, capital investment activity has progressed as planned in our key development areas. For the three and nine months ended September 30, 2014 our Canadian exploration and development expenditures are moderately lower compared to the same period in 2013 due to our current focus on our Eagle Ford assets. Although our average per well costs are higher on our U.S. properties, we generate higher operating netback as a result of incurring exploration and development expenditures in this division.

On September 24, 2014 we disposed of our 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 $295.7 million, $32.5 million, $2.0 million, respectively, for cash proceeds of $341.6 million.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands except for %)	**2014**	2013	**2014**	2013
Cash flow from operating activities	**$ 347,102**	$ 204,093	**$ 620,796**	$ 459,573
Change in non-cash working capital	**(24,094)**	1,776	**57,846**	21,334
Asset retirement expenditures	**3,894**	3,944	**10,782**	8,190
Financing costs	**(31,312)**	(12,478)	**(61,498)**	(37,858)
Accretion on asset retirement obligations	**1,786**	1,817	**5,307**	5,167
Accretion on notes and long-term debt	**588**	166	**1,044**	488
Funds from operations	**$ 297,964**	$ 199,318	**$ 634,277**	$ 456,894
Dividends declared	**$ 119,785**	$ 82,029	**$ 298,509**	$ 244,420
Reinvested dividends	**(30,014)**	(20,675)	**(69,899)**	(66,291)
Cash dividends declared (net of DRIP)	**$ 89,771**	$ 61,354	**$ 228,610**	$ 178,129
Payout ratio(1)	**40%**	41%	**47%**	53%
Payout ratio (net of DRIP)(1)	**30%**	31%	**36%**	39%

(1) Excluding acquisition-related costs, the payout ratio for the nine months ended September 30, 2014 was 44% (34% net of DRIP)

Baytex does not deduct capital expenditures when calculating the payout ratio. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, it is possible that we would be required to reduce or eliminate dividends on our common shares in order to fund capital expenditures. There can be no certainty that we will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $89.8 million and $228.6 million for the three and nine months ended September 30, 2014 were funded by funds from operations of $298.0 million and $634.3 million, respectively.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

We regularly review our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations, dividends and planned capital expenditures. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of dividend is also discretionary, and we have the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes. Further, we believe that our counterparties currently have the financial capacities 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.

($ thousands)	September 30, 2014	December 31, 2013
Bank loan	$ 624,067	$ 223,371
Long-term debt[(1)]	1,380,811	459,540
Working capital deficiency[(2)]	250,939	79,151
Total monetary debt	$ 2,255,817	$ 762,062

(1) Principal amount of instruments.

(2) Working capital is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale, and liabilities related to assets held for sale).

Bank Loan

At September 30, 2014, total monetary debt was $2,255.8 million, as compared to $762.1 million at December 31, 2013. The increase in total monetary debt at September 30, 2014, as compared to December 31, 2013, was primarily due to the acquisition of Aurora, exploration and development expenditures and cash dividends exceeding cash flow from operations during the first nine months of the year.

Baytex had established credit facilities of approximately $1.4 billion with its bank lending syndicate consisting of the following: (i) revolving extendible unsecured credit facilities consisting of a $50 million operating loan and a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex USA Oil & Gas, Inc., both of which have a four-year term (collectively, the “Revolving Facilities”); and (ii) a $200 million non-revolving unsecured syndicated loan with a two-year term (the “Non-Revolving Facility” and, together with the Revolving Facilities, the “Unsecured Facilities”).

The Non-Revolving Facility was a single drawdown facility available solely to finance the acquisition of Aurora. In accordance with the terms of the facility agreement, it was repaid in full on September 29, 2014 using a portion of the proceeds from the sale of the North Dakota assets. As a result, the Non-Revolving Facility was canceled and the available credit facilities as at September 30, 2014 totaled approximately $1.2 billion.

The Unsecured Facilities contain standard commercial covenants for facilities of this nature and the Revolving Facilities do not require any mandatory principal payments prior to maturity. At September 30, 2014, $624.1 million was drawn on the Unsecured Facilities leaving approximately $575.9 million in undrawn credit capacity. A copy of the credit agreement is accessible on the SEDAR website at www.sedar.com (filed under the category “Material Document” on June 11, 2014 and September 9, 2014).

Long term debt

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

Pursuant to the acquisition of Aurora, we 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”). On June 11, 2014, we 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 redeemable at the issuer’s option, in whole or in part, commencing on February 15, 2015 (in the case of the 2017 Notes) and April 1, 2016 (in the case of the 2020 Notes) 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. 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.

The following table lists the financial covenants under the Unsecured Facilities and the senior unsecured notes, and the compliance therewith as at September 30, 2014.

Covenant Description		Position at September 30, 2014
Bank loan	**Maximum Ratio**	
Senior debt to capitalization(1)(2)	0.50:1.00	0.42:1.00
Senior debt to adjusted income(1)(5)(6)	3.00:1.00	1.71:1.00
Total debt to adjusted income(3)(5)(6)	4.00:1.00	1.71:1.00
Long-term debt	**Minimum Ratio**	
Fixed charge coverage(4)(5)(6)	2:00:1.00	9.93:1.00

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

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

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

(4) Fixed charge coverage is computed as the ratio of financing cost to trailing twelve month Adjusted income.

(5) For purposes of the covenant calculations, Aurora's Adjusted income for the trailing twelve months has been included, in accordance with the terms of the credit agreement and the note indentures.

(6) Adjusted income is calculated based on terms and definitions set out in the credit agreement and the note indentures which adjusts net income for financing costs, certain specific unrealized and non-cash transactions, acquisition and disposition activity and is calculated based on a trailing twelve month basis.

Adjusted income for the trailing twelve months ended September 30, 2014 was $1.18 billion.

In the event of a material acquisition, certain of the financial covenants for our credit facilities are relaxed for up to two quarter ends following the closing of such material acquisition, provided that in each quarter: (i) the senior debt to capitalization ratio shall not exceed 0.55:1.00; (ii) the senior debt to adjusted income ratio shall not exceed 3.50:1.00; and (iii) the sole cause of such ratios exceeding the levels set forth above is due to the material acquisition. If we exceed any of the covenants under the Unsecured Facilities, we would be required to repay, refinance or renegotiate the loan terms and conditions which may restrict our ability to pay dividends to our shareholders.

The weighted average interest rate on the bank loan for the three and nine months ended September 30, 2014 was 3.42% and 3.52%, respectively (three and nine months ended September 30, 2013 – 4.21% and 4.80%, respectively).

Pursuant to various agreements with our lenders, we are restricted from paying dividends to shareholders where the dividend would or could have a material adverse effect on us or our subsidiaries' ability to fulfill our respective obligations under our senior unsecured notes and credit facilities.

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 September 30, 2014 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 October 27, 2014, we had 167,036,306 common shares and no preferred shares issued and outstanding. During the nine months ended September 30, 2014 we issued 41,317,163 common shares including 38,433,000 common shares upon closing of the acquisition of Aurora.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of September 30, 2014 and the expected timing for funding these obligations is noted in the table below.

Operating leases	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 480,345**	$ 480,345	$ –	$ –	$ –
Dividends payable to shareholders	**40,010**	40,010	–	–	–
Bank loan(1)	**624,067**	–	–	624,067	–
Long-term debt(2)	**1,380,811**	–	8,854	–	1,371,957
Operating leases	**44,073**	7,831	16,024	15,907	4,311
Processing agreements	**90,225**	11,663	19,571	13,963	45,028
Transportation agreements	**73,900**	11,719	20,444	18,902	22,835
Total	**$ 2,733,431**	$ 551,568	$ 64,893	$ 672,839	$ 1,444,131

(1) The bank loan is a covenant-based loan with a revolving portion that is extendible annually for up to a four year period. Unless extended, the revolving period will end on June 3, 2018, with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

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

QUARTERLY FINANCIAL INFORMATION

	2014			2013				2012
($ thousands, except per common share amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Gross revenues	**634,417**	476,404	385,809	330,712	422,791	341,011	272,945	292,095
Net income	**144,369**	36,799	47,841	31,173	87,331	36,192	10,149	31,620
Per common share – basic	**0.87**	0.27	0.38	0.26	0.70	0.29	0.08	0.26
Per common share – diluted	**0.86**	0.27	0.38	0.25	0.70	0.29	0.08	0.26

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: the anticipated benefits from the acquisition of Aurora; our expectations that the Aurora assets have infrastructure in place that support future annual production growth; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; our business strategies, plans and objectives; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; funding sources for our cash dividends and capital program; the timing of funding our financial obligations; and the existence, operation and strategy of our risk management program. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: failure to realize the anticipated benefits of the acquisition of Aurora; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; third party credit risk; a downgrade of our credit ratings; risks associated with the exploitation of our properties and our ability to acquire reserves; increases in operating costs; changes in government regulations that affect the oil and gas industry; changes to royalty or mineral/severance tax regimes; risks relating to hydraulic fracturing; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties operated by third parties; risks associated with delays in business operations; risks associated with the marketing of *our petroleum and natural gas production; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; expansion of our operations; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the activities of our operating entities and their key personnel and information systems; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonal weather patterns; our permitted investments; access to technological advances; changes in the demand for oil and natural gas products; involvement in legal, regulatory and tax proceedings; the failure of third parties to comply with confidentiality agreements; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond the control of Baytex. 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, 2013, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.*

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	September 30, 2014	December 31, 2013
ASSETS		
Current assets		
Cash	$ 3,153	$ 18,368
Trade and other receivables	265,766	141,651
Crude oil inventory	497	1,507
Financial derivatives	46,552	10,087
Assets held for sale	–	73,634
	315,968	245,247
Non-current assets		
Financial derivatives	23,414	–
Exploration and evaluation assets (note 6)	531,556	162,987
Oil and gas properties (note 7)	4,856,589	2,222,786
Other plant and equipment	33,884	29,559
Other assets (note 5)	3,829	–
Goodwill (note 8)	672,402	37,755
TOTAL ASSETS	$ 6,437,642	$ 2,698,334
LIABILITIES		
Current liabilities		
Trade and other payables	$ 480,345	$ 213,091
Dividends payable to shareholders	40,010	27,586
Financial derivatives	14,105	18,632
Liabilities related to assets held for sale	–	10,241
	534,460	269,550
Non-current liabilities		
Bank loan (note 9)	624,067	223,371
Long-term debt (note 10)	1,361,232	452,030
Asset retirement obligations (note 11)	258,860	221,628
Deferred income tax liability	833,408	248,401
Financial derivatives	3,438	869
	3,615,465	1,415,849
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 12)	3,540,481	2,004,203
Contributed surplus	33,064	53,081
Accumulated other comprehensive income	94,415	1,484
Deficit	(845,783)	(776,283)
	2,822,177	1,282,485
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,437,642	$ 2,698,334

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Revenues, net of royalties (note 16)	$ 483,493	$ 339,395	$ 1,158,544	$ 846,063
Expenses				
Production and operating	93,937	72,565	238,115	206,780
Transportation and blending	35,619	33,178	120,259	120,754
Exploration and evaluation (note 6)	1,637	2,160	16,145	7,737
Depletion and depreciation	172,024	74,397	360,208	239,507
General and administrative	16,770	10,970	42,978	33,060
Acquisition-related costs	–	–	36,973	–
Share-based compensation (note 13)	6,854	8,586	22,941	27,524
Financing costs (note 17)	31,312	12,478	61,498	37,858
(Gain) loss on financial derivatives (note 19)	(90,532)	19,065	(48,487)	18,515
Foreign exchange loss (gain) (note 18)	57,046	(4,058)	43,109	1,077
Gain on divestiture of oil and gas properties	(26,847)	(38)	(45,588)	(20,989)
	297,820	229,303	848,151	671,823
Net income before income taxes	185,673	110,092	310,393	174,240
Income tax expense (note 15)				
Current income tax expense (recovery)	52,461	(6,821)	52,461	(6,821)
Deferred income tax (recovery) expense	(11,157)	29,582	28,923	47,389
	41,304	22,761	81,384	40,568
Net income attributable to shareholders	$ 144,369	$ 87,331	$ 229,009	$ 133,672
Other comprehensive income				
Foreign currency translation adjustment	155,498	(5,603)	108,373	5,740
Comprehensive income	$ 299,867	$ 81,728	$ 337,382	$ 139,412
Net income per common share (note 14)				
Basic	$ 0.87	$ 0.70	$ 1.60	$ 1.08
Diluted	$ 0.86	$ 0.70	$ 1.59	$ 1.07
Weighted average common shares (note 14)				
Basic	166,189	124,172	142,730	123,318
Diluted	167,300	125,570	144,222	124,860

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus[1]	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2012	$ 1,860,358	$ 65,615	$ (12,462)	$ (614,099)	**$ 1,299,412**
Dividends to shareholders	–	–	–	(244,420)	**(244,420)**
Exercise of share rights	19,596	(12,184)	–	–	**7,412**
Vesting of share awards	22,339	(22,339)	–	–	**–**
Share-based compensation	–	27,524	–	–	**27,524**
Issued pursuant to dividend reinvestment plan	66,725	–	–	–	**66,725**
Comprehensive income for the period	–	–	5,740	133,672	**139,412**
Balance at September 30, 2013	$ 1,969,018	$ 58,616	$ (6,722)	$ (724,847)	**$ 1,296,065**
Balance at December 31, 2013	$ 2,004,203	$ 53,081	$ 1,484	$ (776,283)	**$ 1,282,485**
Dividends to shareholders	–	–	–	(298,509)	**(298,509)**
Exercise of share rights	18,759	(10,692)	–	–	**8,067**
Vesting of share awards	32,266	(32,266)	–	–	**–**
Share-based compensation	–	22,941	–	–	**22,941**
Issued for cash	1,495,044	–	–	–	**1,495,044**
Issuance costs, net of tax	(78,468)	–	–	–	**(78,468)**
Issued pursuant to dividend reinvestment plan	68,677	–	–	–	**68,677**
Accumulated other comprehensive income recognized on disposition of foreign operation	–	–	(15,442)	–	**(15,442)**
Comprehensive income for the period	–	–	108,373	229,009	**337,382**
Balance at September 30, 2014	$ 3,540,481	$ 33,064	$ 94,415	$ (845,783)	**$ 2,822,177**

(1) Share-based compensation is accumulated in contributed surplus.

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands of Canadian dollars) (unaudited)	**2014**	2013	**2014**	2013
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income for the period	**$ 144,369**	$ 87,331	**$ 229,009**	$ 133,672
Adjustments for:				
Share-based compensation (note 13)	**6,854**	8,586	**22,941**	27,524
Unrealized foreign exchange loss (gain) (note 18)	**54,937**	(4,030)	**40,014**	4,706
Exploration and evaluation	**1,637**	2,160	**16,145**	7,737
Depletion and depreciation	**172,024**	74,397	**360,208**	239,507
Unrealized (gain) loss on financial derivatives (note 19)	**(98,688)**	(653)	**(76,187)**	11,693
Gain on divestitures of oil and gas properties	**(26,847)**	(38)	**(45,588)**	(20,989)
Current income tax expense on divestitures	**52,461**	–	**52,461**	–
Deferred income tax (recovery) expense	**(11,157)**	29,582	**28,923**	47,389
Financing costs (note 17)	**31,312**	12,478	**61,498**	37,858
Change in non-cash working capital	**24,094**	(1,776)	**(57,846)**	(21,334)
Asset retirement obligations settled (note 11)	**(3,894)**	(3,944)	**(10,782)**	(8,190)
	347,102	204,093	**620,796**	459,573
Financing activities				
Payments of dividends	**(89,770)**	(61,437)	**(217,407)**	(177,117)
Increase (decrease) in secured bank loan (note 9)	**–**	19,217	**(223,371)**	128,257
(Decrease) increase in unsecured bank loan (note 9)	**(333,027)**	–	**476,316**	–
Net proceeds from issuance of long-term debt	**–**	–	**849,944**	–
Tender of long-term debt	**–**	–	**(793,099)**	–
Issuance of common shares on share rights (note 12)	**3,345**	2,111	**8,067**	7,412
Issuance of common shares, net of issue costs (note 12)	**–**	–	**1,401,317**	–
Other assets (note 5)	**–**	–	**(4,085)**	–
Interest paid	**(19,492)**	(18,754)	**(48,952)**	(40,753)
	(438,944)	(58,863)	**1,448,730**	(82,201)
Investing activities				
Additions to exploration and evaluation assets (note 6)	**(2,735)**	(2,545)	**(11,883)**	(7,608)
Additions to oil and gas properties (note 7)	**(227,297)**	(118,939)	**(539,490)**	(458,232)
Property acquisitions	**(46)**	18	**(10,639)**	(36)
Corporate acquisition (note 4)	**–**	(3,586)	**(1,866,307)**	(3,586)
Proceeds from divestiture of oil and gas properties	**341,954**	730	**342,768**	44,962
Additions to other plant and equipment, net of disposals	**(1,843)**	(12)	**(6,704)**	(4,732)
Change in non-cash working capital	**(33,466)**	(22,850)	**6,742**	52,085
	76,567	(147,184)	**(2,085,513)**	(377,147)
Impact of foreign currency translation on cash balances	**276**	(85)	**772**	(1,747)
Change in cash	**(14,999)**	(2,039)	**(15,215)**	(1,522)
Cash, beginning of period	**18,152**	2,354	**18,368**	1,837
Cash, end of period	**$ 3,153**	$ 315	**$ 3,153**	$ 315

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at September 30, 2014 and December 31, 2013 and for the three and nine months ended September 30, 2014 and 2013

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

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange ("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 condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2013. The Company's accounting policies are unchanged compared to December 31, 2013 except as listed in note 3 "Changes in Accounting Policies" of the unaudited condensed consolidated financial statements as of March 31, 2014. The use of estimates and judgments is also consistent with the December 31, 2013 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on October 29, 2014.

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

3. SEGMENTED FINANCIAL INFORMATION

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

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada.
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the states of Texas and North Dakota, USA. The North Dakota assets were sold in September 2014.
- Corporate includes corporate activities and items not allocated between segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Revenues, net of royalties	**$ 294,950**	$ 318,630	**$ 188,543**	$ 20,765	**$ –**	$ –	**$ 483,493**	$ 339,395
Expenses								
Production and operating	**66,311**	66,501	**27,626**	6,064	**–**	–	**93,937**	72,565
Transportation and blending	**30,931**	33,178	**4,688**	–	**–**	–	**35,619**	33,178
Exploration and evaluation	**1,043**	1,217	**594**	943	**–**	–	**1,637**	2,160
Depletion and depreciation	**78,573**	67,938	**92,582**	5,570	**869**	889	**172,024**	74,397
General and administrative	**–**	–	**–**	–	**16,770**	10,970	**16,770**	10,970
Share-based compensation	**–**	–	**–**	–	**6,854**	8,586	**6,854**	8,586
Financing costs	**–**	–	**–**	–	**31,312**	12,478	**31,312**	12,478
(Gain) loss on financial derivatives	**–**	–	**–**	–	**(90,532)**	19,065	**(90,532)**	19,065
Foreign exchange loss (gain)	**–**	–	**–**	–	**57,046**	(4,058)	**57,046**	(4,058)
Gain on divestiture of oil and gas properties	**–**	(38)	**(26,847)**	–	**–**	–	**(26,847)**	(38)
	176,858	168,796	**98,643**	12,577	**22,319**	47,930	**297,820**	229,303
Net income before income taxes	**118,092**	149,834	**89,900**	8,188	**(22,319)**	(47,930)	**185,673**	110,092
Income tax expense								
Current income tax expense (recovery)	**–**	–	**52,461**	(6,821)	**–**	–	**52,461**	(6,821)
Deferred income tax expense (recovery)	**39,199**	35,592	**(43,755)**	5,126	**(6,601)**	(11,135)	**(11,157)**	29,582
	39,199	35,592	**8,706**	(1,695)	**(6,601)**	(11,135)	**41,304**	22,761
Net income	**$ 78,893**	$ 114,242	**$ 81,194**	$ 9,883	**$ (15,718)**	$ (36,795)	**$ 144,369**	$ 87,331
Total capital expenditures[(1)]	**$ 76,233**	$ 112,716	**$ (188,109)**	$ 11,606	**$ 1,843**	$ 12	**$ (110,033)**	$ 124,334

(1) Includes acquisitions and divestitures.

Nine Months Ended September 30	Canada 2014	Canada 2013	U.S. 2014	U.S. 2013	Corporate 2014	Corporate 2013	Consolidated 2014	Consolidated 2013
Revenues, net of royalties	**$ 899,721**	$ 797,265	**$ 258,823**	$ 48,798	**$ –**	$ –	**$1,158,544**	$ 846,063
Expenses								
Production and operating	**198,867**	191,142	**39,248**	15,638	**–**	–	**238,115**	206,780
Transportation and blending	**114,419**	120,754	**5,840**	–	**–**	–	**120,259**	120,754
Exploration and evaluation	**9,116**	5,260	**7,029**	2,477	**–**	–	**16,145**	7,737
Depletion and depreciation	**237,029**	222,700	**121,048**	14,873	**2,131**	1,934	**360,208**	239,507
General and administrative	**–**	–	**–**	–	**42,978**	33,060	**42,978**	33,060
Acquisition-related costs	**–**	–	**–**	–	**36,973**	–	**36,973**	–
Share-based compensation	**–**	–	**–**	–	**22,941**	27,524	**22,941**	27,524
Financing costs	**–**	–	**–**	–	**61,498**	37,858	**61,498**	37,858
(Gain) loss on financial derivatives	**–**	–	**–**	–	**(48,487)**	18,515	**(48,487)**	18,515
Foreign exchange loss	**–**	–	**–**	–	**43,109**	1,077	**43,109**	1,077
(Gain) loss on divestiture of oil and gas properties	**(18,741)**	(22,468)	**(26,847)**	1,479	**–**	–	**(45,588)**	(20,989)
	540,690	517,388	**146,318**	34,467	**161,143**	119,968	**848,151**	671,823
Net income before income taxes	**359,031**	279,877	**112,505**	14,331	**(161,143)**	(119,968)	**310,393**	174,240
Income tax expense								
Current income tax expense (recovery)	**–**	–	**52,461**	(6,821)	**–**	–	**52,461**	(6,821)
Deferred income tax expense (recovery)	**102,157**	66,422	**(37,283)**	7,024	**(35,951)**	(26,057)	**28,923**	47,389
	102,157	66,422	**15,178**	203	**(35,951)**	(26,057)	**81,384**	40,568
Net income	**$ 256,874**	$ 213,455	**$ 97,327**	$ 14,128	**$ (125,192)**	$ (93,911)	**$ 229,009**	$ 133,672
Total capital expenditures[(1)]	**$ 337,343**	$ 356,858	**$2,794,849**	$ 67,642	**$ 6,704**	$ 4,732	**$3,138,896**	$ 429,232
As at September 30, 2014 and December 31, 2013								
Total Assets	**$2,488,730**	$2,340,702	**$3,845,062**	$ 322,150	**$ 103,850**	$ 35,482	**$6,437,642**	$2,698,334

(1) Includes acquisitions and divestitures.

4. 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 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 debt 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**

For the period from June 11, 2014 to September 30, 2014, the acquired properties contributed revenues, net of royalties, of $202.6 million and operating income (revenues, net of royalties less production and operating expenses and transportation and blending expenses) of $171.2 million to Baytex's operations. If the acquisition had occurred on January 1, 2014, management estimates for the nine months ended September 30, 2014, that the acquired properties would have contributed revenues, net of royalties, of approximately $454.4 million and operating income of approximately $390.5 million.

The fair values of assets and liabilities recognized are estimates due to the uncertainty of provisional amounts recognized. Amendments may be made to the purchase price equation as the cost estimates and balances are finalized.

5. OTHER ASSETS

Other assets include debt issuance costs related to the restructuring of the credit facilities (note 9) and will be amortized as debt financing costs over the four-year term of the credit facilities.

6. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2012	**$ 240,015**
Capital expenditures	11,846
Property acquisition	3,060
Exploration and evaluation expense	(10,286)
Transfer to oil and gas properties	(82,886)
Divestitures	(1,109)
Assets held for sale	(305)
Foreign currency translation	2,652
As at December 31, 2013	**$ 162,987**
Capital expenditures	11,883
Corporate acquisition (note 4)	391,127
Property acquisition	10,080
Exploration and evaluation expense	(16,145)
Transfer to oil and gas properties	(9,086)
Divestitures	(33,413)
Foreign currency translation	14,123
As at September 30, 2014	**$ 531,556**

7. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2012	**$ 2,758,309**
Capital expenditures	539,054
Corporate acquisition	100
Property acquisitions	108
Transferred from exploration and evaluation assets	82,886
Assets held for sale	(110,386)
Change in asset retirement obligations	(28,734)
Divestitures	(33,907)
Foreign currency translation	16,338
As at December 31, 2013	**$ 3,223,768**
Capital expenditures	539,490
Corporate acquisition (note 4)	2,520,612
Property acquisitions	83,314
Transferred from exploration and evaluation assets	9,086
Change in asset retirement obligations	41,121
Divestitures	(360,960)
Foreign currency translation	99,928
As at September 30, 2014	**$ 6,156,359**

Accumulated depletion	
As at December 31, 2012	**$ 720,733**
Depletion for the period	325,793
Divestitures	(10,191)
Assets held for sale	(37,057)
Foreign currency translation	1,704
As at December 31, 2013	**$ 1,000,982**
Depletion for the period	357,689
Divestitures	(64,326)
Foreign currency translation	5,425
As at September 30, 2014	**$ 1,299,770**

Carrying value	
As at December 31, 2013	**$ 2,222,786**
As at September 30, 2014	**$ 4,856,589**

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 $295.7 million, $32.5 million, $2.0 million, respectively, for cash proceeds of $341.6 million resulting in a gain of $11.4 million before tax. An additional $15.5 million was recognized in gain on divestiture of oil and gas properties resulting from the reclassification of accumulated other comprehensive income on disposition.

8. GOODWILL

As at December 31, 2012 and 2013	**$ 37,755**
Acquired goodwill	615,338
Foreign currency translation	19,309
As at September 30, 2014	**$ 672,402**

9. BANK LOAN

	September 30, 2014	December 31, 2013
Bank loan	**$ 624,067**	$ 223,371

Baytex had established credit facilities totaling approximately $1.4 billion with its bank lending syndicate consisting of the following: (i) revolving extendible unsecured credit facilities consisting of a $50 million operating loan and a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex USA Oil & Gas, Inc., both of which have a four-year term (collectively, the "Revolving Facilities"); and (ii) a $200 million non-revolving unsecured syndicated loan with a two-year term (the "Non-Revolving Facility" and, together with the Revolving Facilities, the "Unsecured Facilities").

The Non-Revolving Facility was a single drawdown facility, which was available solely to finance the acquisition of Aurora. In accordance with the terms of the Non-Revolving Facility agreement, it was repaid in full on September 29, 2014 using a portion of the proceeds from the sale of the North Dakota assets. At September 30, 2014 the available credit facilities were approximately $1.2 billion.

Unless extended, the revolving period under the Revolving Facilities will end on June 3, 2018 with all amounts to be re-paid on such date. Baytex may, once in each calendar year, request that the lenders under the Revolving Facilities extend the revolving period for up to four years (subject to a maximum four-year term at any time). The Revolving Facilities do not require any mandatory principal payments prior to maturity and do not include a term-out feature or a borrowing base restriction. The Revolving Facilities include an option allowing such facilities to be increased by up to $250 million, subject to existing or new lender(s) providing commitments for any such increase.

The Unsecured Facilities contain standard commercial covenants for facilities of this nature and are guaranteed by Baytex and its material subsidiaries. Advances (including letters of credit) under the Unsecured Facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. In the event that Baytex does not comply with the covenants under the Unsecured Facilities, its ability to pay dividends to its shareholders may be restricted.

The weighted average interest rate on the bank loan for the three and nine months ended September 30, 2014 was 3.42% and 3.52%, respectively, and 4.21% and 4.80% for the three and nine months ended September 30, 2013, respectively.

10. LONG-TERM DEBT

	September 30, 2014	December 31, 2013
9.875% notes (US$7,900 – principal) due February 15, 2017	$ 9,467	$ –
7.500% notes (US$6,400 – principal) due April 1, 2020	7,919	–
6.750% notes (US$150,000 – principal) due February 17, 2021	166,316	157,673
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	294,731	294,357
5.125% notes (US$400,000 – principal) due June 1, 2021	442,863	–
5.625% notes (US$400,000 – principal) due June 1, 2024	439,936	–
	$1,361,232	$ 452,030

The 2017 and 2020 notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on February 15, 2015 (in the case of the 2017 notes) and April 1, 2016 (in the case of the 2020 notes) at specified redemption prices.

The 2021 and 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.

Each of the outstanding notes are redeemable at the Company's option in accordance with the redemption provisions contained in the indenture governing such notes. Baytex has recognized the fair value of this redemption feature as a derivative financial asset. The fair value has been estimated using a valuation model that considers current bond prices and the spreads associated with the outstanding notes compared to the fixed redemption rates. A fair value gain of $2.3 million and $14.4 million for the three and nine months ended September 30, 2014, respectively, (three and nine months ended September 30, 2013 – $nil) has been recorded as a gain on financial derivatives. As at September 30, 2014, $20.0 million has been included in financial derivatives (December 31, 2013 – $nil) representing the fair value of the redemption feature on all notes.

Accretion expense on the outstanding notes of $0.3 million has been recorded in financing costs for the three months ended September 30, 2014 (three months ended September 30, 2013 – $0.2 million) and $0.8 million for the nine months ended September 30, 2014 (nine months ended September 30, 2013 – $0.5 million).

11. ASSET RETIREMENT OBLIGATIONS

	September 30, 2014	December 31, 2013
Balance, beginning of period	$ 221,628	$ 265,520
Liabilities incurred	6,081	14,901
Liabilities settled	(10,782)	(12,076)
Liabilities acquired	2,271	–
Liabilities divested	(5,383)	(1,409)
Corporate acquisition (note 4)	1,217	–
Accretion	5,307	7,011
Change in estimate(1)	38,152	(42,226)
Liabilities related to assets held for sale	–	(10,241)
Foreign currency translation	369	148
Balance, end of period	$ 258,860	$ 221,628

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

12. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at September 30, 2014, 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, 2012	**121,868**	**$ 1,860,358**
Issued on exercise of share rights	802	10,586
Transfer from contributed surplus on exercise of share rights	–	20,333
Transfer from contributed surplus on vesting and conversion of share awards	555	24,542
Issued pursuant to dividend reinvestment plan	2,167	88,384
Balance, December 31, 2013	**125,392**	**$ 2,004,203**
Issued on exercise of share rights	502	8,067
Transfer from contributed surplus on exercise of share rights	–	10,692
Transfer from contributed surplus on vesting and conversion of share awards	791	32,266
Issued for cash	38,433	1,495,044
Issuance costs, net of tax	–	(78,468)
Issued pursuant to dividend reinvestment plan	1,591	68,677
Balance, September 30, 2014	**166,709**	**$ 3,540,481**

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.

The Company declared monthly dividends of $0.24 per common share from June 2014 to September 2014 and $0.22 per common share for the first five months of 2014. During the three and nine months ended September 30, 2014, total dividends declared of $119.8 million ($89.8 million net of dividend reinvestment) and $298.5 million ($228.6 million net of dividend reinvestment), respectively, were declared.

13. EQUITY BASED PLANS

Share Award Incentive Plan

The Company recorded compensation expense related to the share awards of $6.9 million for the three months ended September 30, 2014 (three months ended September 30, 2013 – $8.4 million) and $22.9 million for the nine months ended September 30, 2014 (nine months ended September 30, 2013 – $27.0 million).

The estimated weighted average fair value for share awards at the measurement date is $43.79 per restricted award and performance award granted during the nine months ended September 30, 2014 (nine months ended September 30, 2013 – $42.91 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Number of share awards *(000s)*
Balance, December 31, 2012	**566**	**388**	**954**
Granted	437	374	811
Vested and converted to common shares	(215)	(142)	(357)
Forfeited	(65)	(40)	(105)
Balance, December 31, 2013	**723**	**580**	**1,303**
Granted	533	483	1,016
Vested and converted to common shares	(307)	(241)	(548)
Forfeited	(139)	(154)	(293)
Balance, September 30, 2014	**810**	**668**	**1,478**

Share Rights Plan

No new grants have been made under the Share Rights Plan since December 31, 2010. All outstanding share rights have been fully expensed and are exercisable.

The number of share rights outstanding and exercise prices are detailed below:

	Number of share rights *(000s)*	Weighted average exercise price
Balance, December 31, 2012(1)	**1,525**	**$ 16.79**
Exercised(2)	(802)	13.53
Forfeited(1)	(6)	27.77
Balance, December 31, 2013(1)	**717**	**$ 17.69**
Exercised(2)	(502)	16.03
Forfeited(1)	–	–
Balance, September 30, 2014(1)	**215**	**$ 18.68**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price for dividends and distributions.

(2) Weighted average exercise price includes rights exercised at both original grant prices and original grant prices reduced for dividends and distributions subsequent to grant date.

14. NET INCOME PER SHARE

	Three Months Ended September 30					
	2014			2013		
	Net income	**Common shares (000s)**	**Net income per share**	Net income	Common shares (000s)	Net income per share
Net income – basic	**$ 144,369**	**166,189**	**$ 0.87**	$ 87,331	124,172	$ 0.70
Dilutive effect of share awards	**–**	**928**	**–**	–	937	–
Dilutive effect of share rights	**–**	**183**	**–**	–	461	–
Net income – diluted	**$ 144,369**	**167,300**	**$ 0.86**	$ 87,331	125,570	$ 0.70

	Nine Months Ended September 30					
	2014			2013		
	Net income	Common shares (000s)	Net income per share	Net income	Common shares (000s)	Net income per share
Net income – basic	$ 229,009	142,730	$ 1.60	$ 133,672	123,318	$ 1.08
Dilutive effect of share awards	–	1,258	–	–	1,027	–
Dilutive effect of share rights	–	234	–	–	515	–
Net income – diluted	$ 229,009	144,222	$ 1.59	$ 133,672	124,860	$ 1.07

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2014	2013
Net income before income taxes	$ 310,393	$ 174,240
Expected income taxes at the statutory rate of 25.47% (2013 – 25.51%)(1)	79,057	44,449
Increase (decrease) in income taxes resulting from:		
Share-based compensation	6,309	7,020
Effect of rate adjustments for foreign jurisdictions	(1,254)	(4,067)
Other	(2,728)	(6,834)
Income tax expense	$ 81,384	$ 40,568

(1) The change in statutory rate is mainly related to changes in the provincial apportionment of income.

16. REVENUES

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Petroleum and natural gas revenues	$ 633,266	$ 422,068	$ 1,492,588	$ 1,033,927
Royalty charges	(150,922)	(83,396)	(338,083)	(190,684)
Royalty income	1,151	723	3,626	2,820
Other income	(2)	–	413	–
Revenues, net of royalties	$ 483,493	$ 339,395	$ 1,158,544	$ 846,063

17. FINANCING COSTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Bank loan and other	$ 8,919	$ 2,884	$ 16,332	$ 7,364
Long-term debt	20,352	7,755	39,547	23,149
Accretion on asset retirement obligations	1,786	1,817	5,307	5,167
Debt financing costs	255	22	312	2,178
Financing costs	$ 31,312	$ 12,478	$ 61,498	$ 37,858

18. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Unrealized foreign exchange loss (gain)	$ 54,937	$ (4,030)	$ 40,014	$ 4,706
Realized foreign exchange loss (gain)	2,109	(28)	3,095	(3,629)
Foreign exchange loss (gain)	$ 57,046	$ (4,058)	$ 43,109	$ 1,077

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Foreign Currency Risk

At September 30, 2014, the Company had in place the following currency derivative contracts relating to operations:

Type	Period	Amount per month	Sales Price	Reference
Monthly average rate forward	October to December 2014	US$3.50 million	1.0671	(2)
Monthly forward spot sale	October to December 2014	US$9.50 million	1.0517	(2)
Monthly average collar	October to December 2014	US$1.00 million	1.0300-1.0600	(2)(5)
Monthly average collar	October to December 2014	US$7.00 million	1.0469-1.1100	(2)(3)
Monthly average range forward	October to December 2014	US$2.00 million	1.0800-1.1400	(1)(5)
Contingent average rate forward	October to December 2014	US$1.00 million	1.1400	(1)(6)
Monthly range forward spot sale	October to December 2014	US$1.00 million	1.0550-1.1303	(1)(5)
Contingent monthly forward spot sale	October to December 2014	US$0.50 million	1.1303	(1)(6)
Monthly average rate forward	October 2014 to December 2015	US$1.50 million	1.0933	(1)
Monthly forward spot sale	October 2014 to December 2015	US$2.00 million	1.1100	(2)
Monthly average collar	January 2015	US$6.50 million	1.0675-1.1200	(1)(3)
Monthly average range forward	January 2015	US$0.50 million	1.0950-1.1200	(1)(5)
Contingent average rate forward	January 2015	US$0.50 million	1.1200	(1)(6)
Monthly forward spot sale	January 2015 to June 2015	US$2.00 million	1.1150	(2)
Monthly range forward spot sale	January 2015 to June 2015	US$1.00 million	1.1000-1.1550	(1)(5)
Contingent monthly forward spot sale	January 2015 to June 2015	US$1.00 million	1.1550	(1)(6)
Monthly range forward spot sale	January 2015 to June 2015	US$1.00 million	1.1000-1.1618	(1)(5)
Contingent monthly forward spot sale	January 2015 to June 2015	US$1.00 million	1.1618	(1)(6)
Monthly average rate forward	January 2015 to December 2015	US$1.00 million	1.1055	(2)
Monthly forward spot sale	January 2015 to December 2015	US$2.00 million	1.1050	(2)
Monthly range forward spot sale	January 2015 to December 2015	US$1.00 million	1.1000-1.1674	(1)(5)
Contingent monthly forward spot sale	January 2015 to December 2015	US$1.00 million	1.1674	(1)(6)
Monthly average range forward	February 2015 to March 2015	US$0.50 million	1.1050-1.1350	(1)(5)
Contingent average rate forward	February 2015 to March 2015	US$0.50 million	1.1350	(1)(6)
Sold call option	January 2015 to December 2015	US$3.00 million	1.0990	(1)(4)
Sold call option	January 2015 to December 2015	US$4.00 million	1.0925	(1)(4)

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

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

(3) Settlement price above the upper end of the price collar will result in settlement at the lower end of the price collar.

(4) Counterparty has the option to enter into a monthly average rate forward for the periods, amounts per month and sales prices noted.

(5) Settlement at or below the lower strike price results in settlement at the lower strike price. Settlement above the lower strike price results in settlement at the higher strike price.

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

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

	Assets		Liabilities	
	September 30, 2014	December 31, 2013	**September 30, 2014**	December 31, 2013
U.S. dollar denominated	**US$221,095**	US$102,367	**US$1,255,899**	US$194,924

Interest Rate Risk

As at September 30, 2014, all interest rate swap financial derivative contracts have expired.

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 derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Baytex. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

Financial Derivative Contracts

At September 30, 2014, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	October 2014	6,558 bbl/d	US$92.78	WTI
Fixed – Sell	October to December 2014	14,500 bbl/d	US$96.40	WTI
Price collar	October to December 2014	491 bbl/d	US$80.00-US$95.50	WTI
Fixed – Sell	October 2014 to March 2015	6,000 bbl/d	US$96.62	WTI
Fixed – Sell	November 2014	6,453 bbl/d	US$92.33	WTI
Fixed – Sell	December 2014	5,939 bbl/d	US$91.77	WTI
Fixed – Sell	January 2015	6,161 bbl/d	US$91.64	WTI
Fixed – Sell	January 2015 to March 2015	1,000 bbl/d	US$95.90	WTI
Fixed – Sell	January 2015 to March 2015	1,000 bbl/d	US$110.00	Brent
Fixed – Sell	January 2015 to June 2015	6,000 bbl/d	US$96.63	WTI
Fixed – Sell	January 2015 to December 2015	4,000 bbl/d	US$95.98	WTI
Sold call option(2)	January 2015 to December 2015	500 bbl/d	US$98.50	WTI
Sold call option(2)	January 2015 to December 2015	500 bbl/d	US$99.00	WTI
Sold call option(2)	January 2015 to March 2015	1,000 bbl/d	US$97.70	WTI
Fixed – Sell	February 2015	6,571 bbl/d	US$91.33	WTI
Fixed – Sell	March 2015	5,742 bbl/d	US$91.31	WTI
Fixed – Sell	April 2015	3,433 bbl/d	US$90.66	WTI
Fixed – Sell	May 2015	3,226 bbl/d	US$90.00	WTI
Sold call option(2)	July 2015 to June 2016	4,000 bbl/d	US$94.00	WTI
Sold call option(2)	July 2015 to June 2016	1,000 bbl/d	US$95.00	WTI
Basis swap	October to December 2014	3,000 bbl/d	WTI less US$21.70	WCS
Bought (sold) put(3)	April 2015	2,300 bbl/d	US$90.66 (US$80.00)	WTI
Bought (sold) put(3)	May 2015	2,129 bbl/d	US$90.01 (US$80.00)	WTI
Bought (sold) put(3)	June 2015	5,367 bbl/d	US$91.12 (US$80.00)	WTI
Bought (sold) put(3)	July 2015	5,032 bbl/d	US$90.00 (US$80.00)	WTI
Bought (sold) put(3)	August 2015	4,903 bbl/d	US$90.00 (US$80.00)	WTI

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

(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

(3) These puts have an upper barrier that ranges between US$100.00 – US$102.00/bbl, WTI price above the barrier price results in settlement at the bought put price.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	October 2014	5,750 mmBtu/d	US$4.19	NYMEX
Fixed – Sell	October to December 2014	2,000 mmBtu/d	US$4.45	NYMEX
Fixed – Sell	October 2014 to March 2015	10,000 mmBtu/d	US$4.08	NYMEX
Fixed – Sell	November 2014 to March 2015	10,000 mmBtu/d	US$4.31	NYMEX
Price collar	October 2014	5,000 mmBtu/d	US$3.90-US$4.50	NYMEX
Sold call option(2)	November 2014 to March 2015	5,000 mmBtu/d	US$4.65	NYMEX
Sold call option(2)	April 2015 to October 2015	5,000 mmBtu/d	US$4.00	NYMEX
Basis swap	October 2014	5,000 mmBtu/d	NYMEX less US$0.3150	AECO
Basis swap	October 2014 to March 2015	17,750 mmBtu/d	NYMEX less US$0.2225	AECO
Basis swap	November 2014 to March 2015	5,000 mmBtu/d	NYMEX less US$0.2700	AECO

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

(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Realized loss on financial derivatives	$ 8,156	$ 19,718	$ 27,700	$ 6,822
Unrealized (gain) loss on financial derivatives	(98,688)	(653)	(76,187)	11,693
(Gain) loss on financial derivatives	$ (90,532)	$ 19,065	$ (48,487)	$ 18,515

Included in unrealized (gain) loss on financial derivatives for the three and nine months ended September 30, 2014 is a gain of $2.3 million and $14.4 million, respectively, related to the redemption feature on outstanding notes included in long-term debt (note 10) (three and nine months ended September 30, 2013 – $nil).

Physical Delivery Contracts

As at September 30, 2014, the following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Price/Unit(1)
WCS Blend	October to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	October to December 2014	3,000 bbl/d	WTI less US$19.07

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

At September 30, 2014, Baytex had committed to deliver the volumes of raw bitumen noted below to market on rail:

Heavy Oil	Period	Term Volume
Raw bitumen	October to December 2014	15,000 bbl/d
Raw bitumen	January 2015 to March 2015	14,500 bbl/d
Raw bitumen	April 2015 to December 2015	7,000 bbl/d
Raw bitumen	January 2016 to December 2016	5,000 bbl/d

20. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

Baytex filed a Short Form Base Shelf Prospectus on October 25, 2013, with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the "Shelf Prospectus"). The Shelf Prospectus allows Baytex to offer and issue common shares, subscription receipts, warrants, options and debt securities by way of one or more prospectus supplements at any time during the 25-month period that the Shelf Prospectus remains in place. The securities may be issued from time to time, at the discretion of Baytex, with an aggregate offering amount not to exceed $750 million.

Any debt securities issued by Baytex pursuant to the Shelf Prospectus will be guaranteed by all of its direct and indirect wholly-owned material subsidiaries (the "Guarantor Subsidiaries"). The guarantees of the Guarantor Subsidiaries are full and unconditional and joint and several. These guarantees may in turn be guaranteed by Baytex. Other than investments in its subsidiaries, Baytex has no independent assets or operations. As at September 30, 2014, all non-minor subsidiaries of Baytex provide guarantees for its indebtedness. There are no significant restrictions on the ability of Baytex to obtain funds from its subsidiaries. In accordance with Rule 3-10(f), Regulation S-X, condensed consolidating financial information is not required.

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
DRIP	Dividend Reinvestment Plan
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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

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

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

Edward Chwyl(2)(3)(4)
Lead Independent Director
Independent Businessman

Naveen Dargan(1)(2)
Independent Businessman

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

Gregory K. Melchin(1)
Independent Businessman

Mary Ellen Peters(1)(2)
Independent Businesswoman

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

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

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Bank of Montreal
Barclays Bank PLC
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
The Toronto-Dominion Bank
Union Bank
Wells Fargo Bank

OFFICERS

James L. Bowzer
President and Chief Executive Officer

Rodney D. Gray
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

Brian G. Ector
Senior Vice President, Capital Markets
and Public Affairs

Kendall D. Arthur
Vice President,
Saskatchewan Business Unit

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

Neal E. Halstead
Vice President, Finance and Controller

Cameron A. Hercus
Vice President, Corporate Development

Ryan M. Johnson
Vice President, Alberta/B.C. Business Unit

Mark A. Montemurro
Vice President, Thermal Projects

Gregory A. Sawchenko
Vice President, Land

Michael L. Verm
Vice President, Eagle Ford Operations

AUDITORS

Deloitte LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE