SUMMARY

- Generated record quarterly production of 60,184 boe/d (89% oil and NGL) in Q3/2013, an increase of 3% over Q2/2013;
- Generated funds from operations ("FFO") of $199.3 million ($1.61 per basic share) during Q3/2013, the highest level of quarterly FFO in our history and an increase of 28% over Q2/2013;
- Earned net income of $87.3 million, or $0.70 per share, an increase of 141% over Q2/2013;
- Produced approximately 26,000 bbl/d from our Peace River area properties in Q3/2013, an increase of 13% over Q2/2013;
- Continued to progress our thermal development with facility construction on time and on budget at both our 15-well CSS module at Cliffdale and our Gemini SAGD pilot project;
- Realized an operating netback (sales price less royalties, production and operating expenses and transportation expenses) in Q3/2013 of $42.14/boe, an increase of 33% over Q2/2013; and
- Ended the third quarter with total monetary debt of $756.6 million, representing a debt-to-FFO ratio of 1.3 times based on FFO over the trailing twelve-month period.

	Three Months Ended			Nine Months Ended	
	September 30, 2013	June 30, 2013	September 30, 2012	**September 30, 2013**	September 30, 2012
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**422,791**	341,011	299,786	**1,036,747**	927,389
Funds from operations[1]	**199,318**	155,804	139,044	**456,894**	405,472
Per share – basic	**1.61**	1.26	1.15	**3.71**	3.39
Per share – diluted	**1.59**	1.25	1.14	**3.66**	3.34
Cash dividends declared[2]	**61,354**	60,328	52,640	**178,129**	160,142
Dividends declared per share	**0.66**	0.66	0.66	**1.98**	1.98
Net income	**87,331**	36,192	26,773	**133,672**	227,011
Per share – basic	**0.70**	0.29	0.22	**1.08**	1.90
Per share – diluted	**0.70**	0.29	0.22	**1.07**	1.87
Exploration and development	**121,484**	177,834	113,126	**465,840**	351,939
Acquisitions, net of divestitures	**2,838**	(1,796)	2,160	**(41,340)**	(302,733)
Total oil and natural gas capital expenditures	**124,322**	176,038	115,286	**424,500**	49,206
Bank loan	**244,651**	225,434	181,785	**244,651**	181,785
Long-term debt	**454,275**	457,680	447,555	**454,275**	447,555
Working capital deficiency (surplus)	**57,703**	87,418	(149,329)	**57,703**	(149,329)
Total monetary debt[3]	**756,629**	770,532	480,011	**756,629**	480,011

	Three Months Ended			Nine Months Ended	
	September 30, 2013	June 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**8,366**	8,202	7,047	**8,163**	7,233
Heavy oil (bbl/d)	**44,908**	42,510	40,580	**41,664**	39,176
Total oil and NGL (bbl/d)	**53,274**	50,712	47,627	**49,827**	46,409
Natural gas (mcf/d)	**41,460**	45,148	40,524	**41,979**	43,336
Oil equivalent (boe/d @ 6:1)(4)	**60,184**	58,236	54,381	**56,823**	53,633
Average prices (before hedging)					
WTI oil (US$/bbl)	**105.82**	94.22	92.22	**98.15**	96.20
WCS heavy oil (US$/bbl)	**88.34**	75.07	70.50	**75.29**	74.20
Edmonton par oil ($/bbl)	**105.07**	92.94	84.79	**95.55**	87.29
Baytex light oil and NGL ($/bbl)	**88.63**	77.85	70.34	**81.23**	74.80
Baytex heavy oil ($/bbl)(5)	**79.29**	63.92	60.11	**66.41**	61.12
Baytex total oil and NGL ($/bbl)	**80.75**	66.17	61.63	**68.83**	63.25
Baytex natural gas ($/mcf)	**2.72**	3.59	2.34	**3.26**	2.26
Baytex oil equivalent ($/boe)	**73.36**	60.42	55.70	**62.77**	56.56
CAD/USD noon rate at period end	**1.0285**	1.0512	0.9837	**1.0285**	0.9837
CAD/USD average rate for period	**1.0385**	1.0231	0.9953	**1.0236**	1.0023
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**44.44**	43.05	50.37	**47.60**	59.40
Low	**37.65**	36.37	39.91	**36.37**	38.54
Close	**42.51**	37.90	46.72	**42.51**	46.72
Volume traded (thousands)	**24,658**	30,085	25,679	**82,511**	83,219
NYSE					
Share price (US$)					
High	**43.08**	42.50	51.73	**47.47**	59.50
Low	**35.72**	34.71	39.50	**34.75**	37.40
Close	**41.27**	36.04	47.44	**41.27**	47.44
Volume traded (thousands)	**3,282**	4,763	5,823	**11,414**	18,568
Common shares outstanding (thousands)	**124,497**	123,593	120,962	**124,497**	120,962

Notes:

(1) Funds from operations is a non-Generally Accepted Accounting Principles ("GAAP") measure that represents cash generated 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, 2013.

(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)), 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 are net of blending costs.

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to: our average production rate for 2013; our exploration and development capital expenditures for 2013; development plans for our properties, including the number of wells to be drilled in the remainder of 2013 and, in some cases, when such wells will commence production; initial production rates from wells drilled; our Peace River heavy oil area, including our assessment of the productivity of recently drilled horizontal wells; our Cliffdale cyclic steam stimulation project, including our assessment of the operations for the initial 10-well module and our plan for a second module, including the timing of drilling the wells, completing plant construction, commencing cold production and commencing steam injection; our plans for the Gemini steam-assisted gravity drainage pilot project, including the timing of construction of the pilot facilities and commencing steam injection; 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 the volatility in heavy oil price differentials by transporting our crude oil to higher value markets by rail; the volume of heavy oil to be transported to market on rail for the fourth quarter of 2013; our average royalty rate for full-year 2013; our debt-to-FFO ratio; the amount of our undrawn credit facilities at September 30, 2013; and our liquidity and financial capacity. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

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 loan. Baytex believes that this measure assists in providing a more complete understanding of our cash liabilities.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product 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 for other entities. Baytex believes that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

Operations Review

Production averaged 60,184 boe/d (89% oil and NGL) during Q3/2013, an increase of 3% over Q2/2013. Capital expenditures for exploration and development activities totaled $121.5 million and included the drilling of 76 (58.3 net) wells with a 98% success rate. In addition, we continued to progress our thermal development with facility construction on time and on budget at both our 15-well cyclic steam stimulation ("CSS") module at Cliffdale and our Gemini steam-assisted gravity drainage ("SAGD") pilot project.

Our third quarter operating results are the strongest in company history. We previously tightened our production guidance following the second quarter of 2013. In recognition of our operational performance, we are further tightening our guidance range for 2013 to 57,500 to 58,000 boe/d, up from previous guidance of 57,000 to 58,000 boe/d and original guidance of 56,000 to 58,000 boe/d.

Given that we expect to achieve the upper end of our original production guidance range, and as we look to maintain our positive operating momentum into 2014, we plan to increase our original 2013 exploration and development budget of $520 million by approximately 5%. The incremental capital will be directed toward our Peace River, Lloydminster and North Dakota operating regions with production additions occurring in Q1/2014. We are in the process of setting our 2014 capital budget, the details of which are expected to be released on December 13, 2013, following approval by our Board of Directors.

Wells Drilled – Three Months Ended September 30, 2013

	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 area	47	31.0	3	3.0	–	–	3	3.0	1	1.0	54	38.0
Peace River area	7	7.0	10	10.0	–	–	1	1.0	–	–	18	18.0
	54	**38.0**	**13**	**13.0**	**–**	**–**	**4**	**4.0**	**1**	**1.0**	**72**	**56.0**
Light oil, NGL and natural gas												
Western Canada	–	–	–	–	1	1.0	–	–	–	–	1	1.0
North Dakota	3	1.3	–	–	–	–	–	–	–	–	3	1.3
	3	**1.3**	**–**	**–**	**1**	**1.0**	**–**	**–**	**–**	**–**	**4**	**2.3**
Total	**57**	**39.3**	**13**	**13.0**	**1**	**1.0**	**4**	**4.0**	**1**	**1.0**	**76**	**58.3**

Wells Drilled – Nine Months Ended September 30, 2013

	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 area	120	92.3	4	4.0	–	–	3	3.0	2	2.0	129	101.3
Peace River area	30	30.0	10	10.0	–	–	31	31.0	–	–	71	71.0
	150	**122.3**	**14**	**14.0**	**–**	**–**	**34**	**34.0**	**2**	**2.0**	**200**	**172.3**
Light oil, NGL and natural gas												
Western Canada	14	11.0	–	–	2	2.0	–	–	–	–	16	13.0
North Dakota	18	8.6	–	–	–	–	–	–	–	–	18	8.6
	32	**19.6**	**–**	**–**	**2**	**2.0**	**–**	**–**	**–**	**–**	**34**	**21.6**
Total	**182**	**141.9**	**14**	**14.0**	**2**	**2.0**	**34**	**34.0**	**2**	**2.0**	**234**	**193.9**

Heavy Oil

In Q3/2013, heavy oil production averaged 44,908 bbl/d, an increase of 6% over Q2/2013. During Q3/2013, we drilled 67 (51.0 net) oil wells, four (4.0 net) stratigraphic and service wells, and one (1.0 net) dry and abandoned well on our heavy oil properties.

Production from our Peace River area properties averaged approximately 26,000 bbl/d in Q3/2013, an increase of 13% over Q2/2013. In Q3/2013, we drilled seven (7.0 net) cold horizontal producers in the Peace River area bringing our year-to-date drilling to 30 (30.0 net) wells. Of the 30 wells drilled during the first nine months of 2013, 28 wells have established average 30-day peak production rates of approximately 700 bbl/d. We plan to drill approximately 10 multi-lateral horizontal wells in the remainder of 2013.

Successful operations continued at our 10-well CSS module at Cliffdale with Q3/2013 production averaging 600 bbl/d. Facility construction at our new 15-well CSS module at Cliffdale is proceeding on schedule with commissioning activities now underway and production facility startup planned for Q4/2013, while steam facility commissioning will occur in Q1/2014. Drilling operations are nearing completion and we expect to commence cold production from the first five of the fifteen wells in Q4/2013.

Recently the Alberta Energy Regulator announced plans to hold a public proceeding that will investigate concerns about odours and emissions associated with heavy oil production in the Peace River area. We welcome this proceeding which will provide an additional opportunity for us to engage with the public about our operations in the area and our efforts to minimize environmental impacts. Baytex has made significant investments to enhance its operations and will continue to operate in an environmentally responsible manner for the benefit of all stakeholders.

In our Lloydminster heavy oil area, Q3/2013 drilling included 21 (11.4 net) horizontal oil wells and 27 (20.6 net) vertical oil wells, with a 97% success rate, and one (1.0 net) thermal infill well and one (1.0 net) SAGD well pair at our Kerrobert SAGD project. The new SAGD well pair commenced production in September and established a 30-day peak production rate of 900 bbl/d. We plan to drill approximately 15 net wells in the Lloydminster area in the remainder of 2013.

Construction of the Gemini SAGD pilot project facilities continued in Q3/2013 and we drilled the pilot SAGD well pair. We remain on track for steaming late this year or early 2014.

Light Oil & Natural Gas

During Q3/2013, natural gas production decreased 8% from Q2/2013 to 41.5 mmcf/d as we focused our activity on higher rate of return oil investment opportunities. Light oil and NGL production increased 2% over Q2/2013 to 8,366 bbl/d.

In our Bakken/Three Forks play in North Dakota, we drilled three (1.3 net) horizontal oil wells and fracture-stimulated four (2.3 net) wells in Q3/2013. During Q3/2013, six Baytex-operated wells on 1,280-acre spacing established average 30-day peak production rates of approximately 470 boe/d.

Financial Review

We generated FFO of $199.3 million ($1.61 per basic share) in Q3/2013, which was the highest level of quarterly FFO in company history, demonstrating the cash flow generating capacity of the company in a strong heavy oil pricing environment. This record level of FFO was achieved notwithstanding that the Company had a net realized loss on financial derivative contracts of $19.7 million. Q3/2013 FFO represents a 28% increase from the $155.8 million generated in Q2/2013 and was the result of higher sales volumes and higher realized commodity prices. During Q3/2013, our operating netback (sales price less royalties, production and operating expenses and transportation expenses) of $42.14/boe represented an improvement of 33% over Q2/2013.

The average WTI price for Q3/2013 was US$105.82/bbl, a 12% increase from Q2/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 17% in Q3/2013, as compared to 20% in Q2/2013. Factors driving a stronger WCS price differential in the third quarter of 2013 included peak demand for heavy oil driven by seasonal product and asphalt demand, and increased volumes of heavy oil being transported by rail which pulled heavy oil supply away from traditional Canadian heavy oil markets. Our realized average oil and NGL price of $80.75/bbl in Q3/2013 (inclusive of our physical hedging gains) increased by 22% from $66.17/bbl in Q2/2013.

We have taken advantage of the recent strength in WTI prices and the weaker Canadian dollar to add to our hedge portfolio. For Q4/2013, we have entered into hedges on approximately 67% of our WTI exposure at a weighted average price of US$99.56/bbl, 46% of our exposure to WCS price differentials primarily through a combination of long term physical supply contracts and rail delivery, 47% of our natural gas price exposure, and 51% of our exposure to currency movements between the U.S. and Canadian dollars. Details of our hedging contracts are contained in the notes to our financial statements.

As part of our hedging program, we are focusing on opportunities to further mitigate the volatility in WCS price differentials by transporting crude oil to higher value markets by rail. During the third quarter, approximately 20,000 bbl/d of our heavy oil volumes were delivered to market by rail, as compared to 7,500 bbl/d for full-year 2012 and 15,000 bbl/d for the first half of 2013. For Q4/2013, we expect to deliver approximately 23,000 to 24,000 bbl/d of our heavy oil volumes by rail, and we continue to explore additional opportunities for rail deliveries.

Royalty rates in Q3/2013 were approximately 20.5% of sales revenues before sales of purchased condensate, consistent with our expectations of 20-21% for full-year 2013. Royalty rates have increased in 2013 as a result of higher commodity prices which impact sliding scale royalty rates, certain oil sands projects reaching payout, and obligations under certain farm-in agreements.

During Q3/2013, we recorded a recovery of cash income taxes of $6.6 million. This is a partial recovery of the income tax paid in 2012 on the disposition of certain of our North Dakota assets. We do not expect to incur any cash income tax expense nor receive any additional tax refund in Q4/2013.

Total monetary debt at the end of Q3/2013 was $756.6 million, representing a debt-to-FFO ratio of 1.3 times based on FFO over the trailing twelve-month period. At the end of the third quarter, Baytex had $605.3 million in undrawn credit facilities and no long-term debt maturities until 2021. Baytex continues to have a strong balance sheet and ample liquidity to allow us execute our growth-and-income model.

As part of normal course business, we maintain a base shelf prospectus on file with securities regulatory authorities in both Canada and the United States to provide us with ready access to the capital markets in the event that we require external financing. On October 25, 2013, we filed a base shelf prospectus which allows us to issue equity and debt securities with an aggregate offering amount not to exceed $750 million (Canadian) at any time during the ensuing 25-month period. Our previously filed base shelf prospectus expired in September 2013.

Conclusion

Our third quarter results were highlighted by the highest quarterly production rate and funds from operations in company history. As compared to Q2/2013, production grew 3% to just over 60,000 boe/d and funds from operations grew 28% to $199.3 million, demonstrating the cash generating capacity of the company in a strong heavy oil pricing environment. Our operations at Peace River, Lloydminster and North Dakota are right on track and we are very pleased, for the second time this year, to be tightening our full-year production guidance range. Our marketing expertise, as demonstrated by the continued growth in our rail volumes, has contributed positively to our bottom line. We continue to have a strong balance sheet and ample liquidity to allow us to execute our growth-and-income model.

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, 2013

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, 2013. This information is provided as of October 29, 2013. 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 2012. 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, 2013, its audited consolidated financial statements for the years ended December 31, 2012 and 2011, together with accompanying notes, and its Annual Information Form for the year ended December 31, 2012. 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) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt

We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

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. As sales volumes are not materially different than production volumes, we believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

RESULTS OF OPERATIONS

Production

	Three Months Ended September 30			Nine Months Ended September 30		
	2013	2012	Change	**2013**	2012	Change
Daily Production						
Light oil and NGL (bbl/d)	**8,366**	7,047	19%	**8,163**	7,233	13%
Heavy oil (bbl/d)[1]	**44,908**	40,580	11%	**41,664**	39,176	6%
Natural gas (mcf/d)	**41,460**	40,524	2%	**41,979**	43,336	(3%)
Total production (boe/d)	**60,184**	54,381	11%	**56,823**	53,633	6%
Production Mix						
Light oil and NGL	**14%**	13%	–	**14%**	14%	–
Heavy oil	**75%**	75%	–	**74%**	73%	–
Natural gas	**11%**	12%	–	**12%**	13%	–

(1) Heavy oil sales volumes may differ from reported production volumes due to changes to Baytex's heavy oil inventory. For the three months ended September 30, 2013, heavy oil sales volumes were 78 bbl/d higher than production volumes (three months ended September 30, 2012 – 148 bbl/d lower). For the nine months ended September 30, 2013, heavy oil sales volumes were 91 bbl/d higher than production volumes (nine months ended September 30, 2012 – 49 bbl/d lower).

Production for the three months ended September 30, 2013 averaged 60,184 boe/d, compared to 54,381 boe/d for the same period in 2012, an 11% increase. Light oil and natural gas liquids ("NGL") production in the third quarter of 2013 increased by 19% to 8,366 bbl/d, as compared to 7,047 bbl/d in the third quarter of 2012, primarily due to successful development activities in the U.S. Heavy oil production for the third quarter of 2013 increased by 11% to 44,908 bbl/d from 40,580 bbl/d in the third quarter of 2012 primarily due to successful development activities in the Peace River area. Natural gas production increased by 2% to 41.5 mmcf/d for the third quarter of 2013, as compared to 40.5 mmcf/d for the same period in 2012, primarily due to successful drilling results in the Pembina region of Alberta.

Production for the nine months ended September 30, 2013 averaged 56,823 boe/d, compared to 53,633 boe/d for the same period in 2012, a 6% increase. Light oil and NGL production in the first nine months of 2013 increased by 13% to 8,163 bbl/d, as compared to 7,233 bbl/d in the first nine months of 2012, primarily due to successful development activities in the U.S., partially offset by the sale of 950 bbl/d associated with our non-operated position in North Dakota in the second quarter of 2012. Heavy oil production for the nine months ended September 30, 2013 increased by 6% to 41,664 bbl/d from 39,176 bbl/d for the same period in 2012 primarily due to successful development activities in the Peace River area. Natural gas production decreased by 3% to 42.0 mmcf/d for the first nine months of 2013, as compared to 43.3 mmcf/d for the same period in 2012, primarily due to natural declines as we focused our capital spending on oil projects.

Commodity Prices

Crude Oil

For the nine months ended September 30, 2013, the West Texas Intermediate ("WTI") oil prompt price averaged US$98.15/bbl. In early July WTI prices staged a US$10.00/bbl rally, and subsequently held a range of US$103-US$109/bbl during the summer. This increase in WTI prices was driven by new pipeline infrastructure connecting Cushing (the WTI valuation point) to the U.S. Gulf Coast which led to a significant draw of Cushing storage during the peak refining season. Towards the end of the summer, escalating conflict in Syria and a strike by Libyan oil production workers drove prices higher, with the daily high over this period of US$110.53/bbl. WTI prices have since eased with a perceived lessening of geopolitical risk, supply returning to market and the start of refinery turnaround season. For the three months ended September 30, 2013, the WTI oil prompt price averaged US$105.82/bbl.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 23% for the nine months ended September 30, 2013 and 17% for the three months ended September 30, 2013, as compared to 23% and 24%, respectively, for the same periods in 2012. Factors driving a stronger WCS differential in the third quarter of 2013 were peak demand for heavy oil driven by seasonal product and asphalt demand, and increased volumes of heavy oil being transported by rail which pulled heavy oil supply away from traditional heavy oil markets. As a result of narrower heavy oil differentials, our realized average oil and NGL price of $80.75/bbl in Q3/2013 (inclusive of our physical hedging gains) increased by 22% from $66.17/bbl in Q2/2013. The WCS differential widened during the October and November trading cycles due to Canadian and U.S. seasonal refinery maintenance and increased supply as incremental oil sands production from planned projects reached the market. Current indications for 2014, based on forward market strips, indicate that WCS will move back towards WTI less $22.50/bbl, or about 23% discount to WTI, in line with previous years' realizations.

Natural Gas

For the nine months ended September 30, 2013, the AECO natural gas price averaged $3.12/mcf, as compared to $2.18/mcf in the same period of 2012. Demand and prices for natural gas peaked in February 2013 and normalized in April 2013 and have since remained near the 5-year average, despite dry gas production remaining elevated. Summer demand was lower than expected due to moderate weather conditions. For the three months ended September 30, 2013, the AECO natural gas price averaged $2.82/mcf, as compared to $2.19/mcf in the same period of 2012.

	Three Months Ended September 30			Nine Months Ended September 30		
	2013	2012	Change	**2013**	2012	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**$ 105.82**	$ 92.22	15%	**$ 98.15**	$ 96.20	2%
WCS heavy oil (US$/bbl)[2]	**$ 88.34**	$ 70.50	25%	**$ 75.29**	$ 74.20	1%
Heavy oil differential[3]	**(17%)**	(24%)		**(23%)**	(23%)	
CAD/USD average exchange rate	**1.0385**	0.9953	4%	**1.0236**	1.0023	2%
Edmonton par oil ($/bbl)	**$ 105.07**	$ 84.79	24%	**$ 95.55**	$ 87.29	9%
AECO natural gas price ($/mcf)[4]	**$ 2.82**	$ 2.19	29%	**$ 3.12**	$ 2.18	43%
Baytex Average Sales Prices						
Light oil and NGL ($/bbl)[6]	**$ 88.63**	$ 70.34	26%	**$ 81.23**	$ 74.80	9%
Heavy oil ($/bbl)[5]	**$ 80.15**	$ 59.45	35%	**$ 65.92**	$ 60.06	10%
Physical forward sales contracts gain (loss) ($/bbl)	**(0.86)**	0.66		**0.49**	1.06	
Heavy oil, net ($/bbl)	**$ 79.29**	$ 60.11	32%	**$ 66.41**	$ 61.12	9%
Total oil and NGL, net ($/bbl)	**$ 80.75**	$ 61.63	31%	**$ 68.83**	$ 63.25	9%
Natural gas ($/mcf)[6]	**$ 2.72**	$ 2.34	16%	**$ 3.26**	$ 2.26	44%
Summary						
Weighted average ($/boe)[6]	**$ 74.00**	$ 55.13	34%	**$ 62.41**	$ 55.66	12%
Physical forward sales contracts gain (loss) ($/boe)	**(0.64)**	0.57		**0.36**	0.90	
Weighted average, net ($/boe)	**$ 73.36**	$ 55.70	32%	**$ 62.77**	$ 56.56	11%

(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.
(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter.
(5) Baytex's realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(6) 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 above pricing information in the table excludes the impact of financial derivatives.

Baytex Average Sales Prices

During the third quarter of 2013, Baytex's average sales price for light oil and NGL was $88.63/bbl, up 26% from $70.34/bbl in the third quarter of 2012, in line with the increase in Edmonton par oil benchmark price. Baytex's realized heavy oil price during the third quarter of 2013, prior to physical forward sales contracts, was $80.15/bbl, or 87% of WCS. This compares to a realized heavy oil price in the third quarter of 2012, prior to physical forward sales contracts, of $59.45/bbl, or 85% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications and has decreased as compared to prior periods due to higher volumes being transported by rail and accessing new markets in the current period. Net of physical forward sales contracts, Baytex's realized heavy oil price during the third quarter of 2013 was $79.29/bbl, up from $60.11/bbl in the third quarter of 2012 due to the narrowing of the heavy oil differential, the higher volumes being transported by rail and a stronger Canadian dollar. Baytex's realized natural gas price for the three months ended September 30, 2013 was $2.72/mcf, up from $2.34/mcf in the third quarter of 2012.

During the first nine months of 2013, Baytex's average sales price for light oil and NGL was $81.23/bbl, up 9% from $74.80/bbl in the same period as 2012, in line with the increase in Edmonton par oil benchmark price. Baytex's realized heavy oil price during the first nine months of 2013, prior to physical forward sales contracts, was $65.92/bbl, or 86% of WCS. This compares to a realized heavy oil price in the first nine months of 2012, prior to physical forward sales contracts, of $60.06/bbl, or 81% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications and has decreased as compared to prior periods due to higher volumes being transported by rail and accessing new markets in the current period. Net of physical forward sales contracts, Baytex's realized heavy oil price during the nine months ended September 30, 2013 was $66.41/bbl, up from $61.12/bbl in the first nine months of 2012 due to the narrowing of the heavy oil differential in the second and third quarters of 2013, partially offset by pipeline apportionments and wider quality discounts in the first quarter of 2013, as well as increased volumes being transported by rail for the nine months ended September 30, 2013. Baytex's realized natural gas price for the nine months ended September 30, 2013 was $3.26/mcf, up from $2.26/mcf in the same period in 2012.

Gross Revenues

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for %)	**2013**	2012	Change	**2013**	2012	Change
Oil revenue						
Light oil and NGL	**$ 68,211**	$ 45,594	50%	**$ 181,005**	$ 148,244	22%
Heavy oil	**328,145**	223,599	47%	**756,962**	655,235	16%
Total oil revenue	**396,356**	269,193	47%	**937,967**	803,479	17%
Natural gas revenue	**10,381**	8,708	19%	**37,344**	26,869	39%
Total oil and natural gas revenue	**406,737**	277,901	46%	**975,311**	830,348	17%
Heavy oil blending revenue	**16,054**	21,885	(27%)	**61,436**	97,041	(37%)
Total petroleum and natural gas revenues	**$ 422,791**	$ 299,786	41%	**$ 1,036,747**	$ 927,389	12%

Petroleum and natural gas revenues increased 41% to $422.8 million for the three months ended September 30, 2013 from $299.8 million for the same period in 2012. The growth in revenues for the three months ended September 30, 2013 was driven by a 47% increase in heavy oil revenues due to higher heavy oil volumes in the Peace River area, higher realized heavy oil pricing resulting from stronger WCS differentials, a 50% increase in light oil and NGL revenues due to success in our U.S. drilling program and higher realized light oil and NGL pricing and a 19% increase in natural gas revenues due to a 16% increase in realized natural gas pricing, as compared to the third quarter of 2012. Revenue for the three months ended September 30, 2013 was slightly offset by the decrease in heavy oil blending revenue, which was down 27% from the same period last year due to an increase in contracted volumes of heavy oil being transported by rail. Unlike transportation through oil pipelines, transportation of heavy oil by rail does not require condensate blending. The decrease in heavy oil blending revenue is offset by a decrease in heavy oil blending costs.

Petroleum and natural gas revenues increased 12% to $1,036.7 million for the nine months ended September 30, 2013 from $927.4 million for the same period in 2012. The growth in revenues was driven by a 16% increase in heavy oil revenues due to higher heavy oil volumes in the Peace River area, higher realized heavy oil pricing resulting from stronger WCS differentials, a 22% increase in light oil and NGL revenues due to success in our U.S. drilling program and higher realized light oil and NGL pricing and a 39% increase in natural gas revenues due to significant increases in realized natural gas pricing, as compared to the same period in 2012. Revenue for the nine months ended September 30, 2013 was slightly offset by the decrease in heavy oil blending revenue, which was down 37% from the same period last year due to an increase in contracted volumes of heavy oil being transported by rail.

Royalties

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for % and per boe)	**2013**	2012	Change	**2013**	2012	Change
Royalties	**$ 83,396**	$ 47,758	75%	**$ 190,684**	$ 146,772	30%
Royalty rates:						
Light oil, NGL and natural gas	**20.3%**	18.6%		**21.2%**	18.5%	
Heavy oil	**20.5%**	16.9%		**19.1%**	17.5%	
Average royalty rates[1]	**20.5%**	17.2%		**19.6%**	17.7%	
Royalty expenses per boe	**$ 15.04**	$ 9.57	57%	**$ 12.27**	$ 10.00	23%

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

Total royalties for the third quarter of 2013 increased to $83.4 million from $47.8 million in the third quarter of 2012. Total royalties for the third quarter of 2013 were 20.5% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 17.2% for the same period in 2012. Total royalties for the nine months ended September 30, 2013 increased to $190.7 million from $146.8 million in the nine months ended September 30, 2012. Total royalties for the first nine months of 2013 were 19.6% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 17.7% for the same period in 2012.

Royalty rates in the three months ended September 30, 2013 for light oil, NGL and natural gas were 20.3%, up from 18.6% in the three months ended September 30, 2012 due to higher royalties on U.S. properties resulting from a carry obligation and higher realized pricing. Royalty rates for heavy oil increased from 16.9% in the three months ended September 30, 2012 to 20.5% in the three months ended September 30, 2013 due to higher commodity prices which impact sliding scale royalty rates, certain farm-in agreements and certain oil sands properties reaching payout.

Royalty rates for light oil, NGL and natural gas increased from 18.5% in the nine months ended September 30, 2012 to 21.2% in the nine months ended September 30, 2013 primarily due to higher royalties on U.S. properties resulting from a carry obligation and higher realized pricing in the first nine months of 2013, partially offset by a higher number of wells qualifying under lower royalty rates and a gas cost allowance credit related to prior years. Royalty rates for heavy oil increased from 17.5% in the nine months ended September 30, 2012, to 19.1% in the nine months ended September 30, 2013 due to higher commodity prices which impact sliding scale royalty rates, certain farm-in agreements and certain oil sands properties reaching payout.

Financial Derivatives

($ thousands)	Three Months Ended September 30 2013	2012	Change	Nine Months Ended September 30 2013	2012	Change
Realized gain (loss) on financial derivatives[1]						
Crude oil	$ (16,713)	$ 6,945	$ (23,658)	$ (1,104)	$ 6,080	$ (7,184)
Natural gas	744	1,642	(898)	823	4,630	(3,807)
Foreign currency	27	1,676	(1,649)	840	4,474	(3,634)
Interest rate	(3,776)	(1,690)	(2,086)	(7,381)	(3,271)	(4,110)
Total	$ (19,718)	$ 8,573	$ (28,291)	$ (6,822)	$ 11,913	$ (18,735)
Unrealized gain (loss) on financial derivatives[2]						
Crude oil	$ (10,463)	$ (12,405)	$ 1,942	$ (15,537)	$ 31,986	$ (47,523)
Natural gas	153	(1,861)	2,014	803	(3,469)	4,272
Foreign currency	18,612	5,813	12,799	(4,095)	6,232	(10,327)
Interest rate	(7,649)	1,314	(8,963)	7,136	1,294	5,842
Total	$ 653	$ (7,139)	$ 7,792	$ (11,693)	$ 36,043	$ (47,736)
Total gain (loss) on financial derivatives						
Crude oil	$ (27,176)	$ (5,460)	$ (21,716)	$ (16,641)	$ 38,066	$ (54,707)
Natural gas	897	(219)	1,116	1,626	1,161	465
Foreign currency	18,639	7,489	11,150	(3,255)	10,706	(13,961)
Interest rate	(11,425)	(376)	(11,049)	(245)	(1,977)	1,732
Total	$ (19,065)	$ 1,434	$ (20,499)	$ (18,515)	$ 47,956	$ (66,471)

(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.

The realized loss of $19.7 million for the three months ended September 30, 2013 on derivative contracts relates to higher WTI prices and losses on interest rate swaps as London Interbank Offer Rates ("LIBOR") remained low. The unrealized mark-to-market gain of $0.7 million for the three months ended September 30, 2013 relates to a strengthening Canadian dollar against the U.S. dollar at September 30, 2013, as compared to June 30, 2013, offset by the settlement of previously recorded unrealized losses on interest rate swaps upon maturity and higher WTI prices at September 30, 2013 as compared to June 30, 2013.

The realized loss of $6.8 million for the nine months ended September 30, 2013 on derivative contracts relates to losses on interest rate swaps as LIBOR remained low as well as higher WTI prices. The unrealized mark-to-market loss of $11.7 million for the nine months ended September 30, 2013 relates to higher WTI prices and a weakening Canadian dollar against the U.S. dollar at September 30, 2013, as compared to December 31, 2012. This was partially offset by settlement of previously recorded unrealized losses on interest rate contracts.

A summary of the risk management contracts in place as at September 30, 2013 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

Production and Operating Expenses

($ thousands except for % and per boe)	Three Months Ended September 30 2013	2012	Change	Nine Months Ended September 30 2013	2012	Change
Production and operating expenses	$ 72,565	$ 57,093	27%	$ 206,780	$ 172,347	20%
Production and operating expenses per boe:						
Heavy oil	$ 12.22	$ 10.68	14%	$ 12.91	$ 10.78	20%
Light oil, NGL and natural gas	$ 15.64	$ 13.67	14%	$ 14.41	$ 14.32	1%
Total	$ 13.09	$ 11.44	14%	$ 13.31	$ 11.74	13%

Production and operating expenses for the three months ended September 30, 2013 increased to $72.6 million from $57.1 million for the same period in 2012. This increase is primarily due to higher production volumes and increases in the costs of fluid handling, repairs and maintenance costs and chemical inputs as well as a prior year equalization charge received in the quarter. Production and operating expenses were $13.09/boe for the three months ended September 30, 2013, as compared to $11.44/boe for the same period in 2012.

Production and operating expenses for the nine months ended September 30, 2013 increased to $206.8 million from $172.3 million for the same period in 2012. This increase is primarily due to higher production volumes, weather conditions in Saskatchewan and North Dakota in the first half of 2013, and increases in the costs of repairs and maintenance, labour, energy and chemical inputs. Production and operating expenses were $13.31/boe for the nine months ended September 30, 2013, as compared to $11.74/boe for the same period in 2012.

Transportation and Blending Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for % and per boe)	2013	2012	Change	2013	2012	Change
Blending expenses	$ 16,054	$ 21,885	(27%)	$ 61,436	$ 97,041	(37%)
Transportation expenses	17,124	22,541	(24%)	59,318	56,912	4%
Total transportation and blending expenses	$ 33,178	$ 44,426	(25%)	$ 120,754	$ 153,953	(22%)
Transportation expenses per boe(1):						
Heavy oil	$ 3.87	$ 5.88	(34%)	$ 4.94	$ 5.08	(3%)
Light oil, NGL and natural gas	$ 0.79	$ 0.52	52%	$ 0.72	$ 0.61	18%
Total	$ 3.09	$ 4.52	(32%)	$ 3.82	$ 3.88	(2%)

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

Transportation and blending expenses for the third quarter of 2013 were $33.2 million, as compared to $44.4 million for the third quarter of 2012. Transportation and blending expenses for the first nine months of 2013 were $120.8 million, as compared to $154.0 million for the same period in 2012.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications and to facilitate the marketing of its heavy oil. The cost of blending diluent is recovered in the sale price of the blended product. In the third quarter of 2013, blending expenses were $16.1 million for the purchase of 1,623 bbl/d of condensate at $107.50/bbl, as compared to $21.9 million for the purchase of 2,498 bbl/d at $95.22/bbl for the same period last year. For the nine months ended September 30, 2013, blending expenses were $61.4 million for the purchase of 2,140 bbl/d of condensate at $105.15/bbl, as compared to $97.0 million for the purchase of 3,407 bbl/d at $103.94/bbl for the same period last year. This decrease in blending for the three and nine months ended September 30, 2013, as compared to the comparable periods of 2012, is due to higher volumes of heavy oil transported by rail which does not require blending diluent.

Transportation expenses decreased to $3.09/boe for the three months ended September 30, 2013, as compared to $4.52/boe for the same period of 2012. The decrease in transportation expenses per barrel of heavy oil for the three months ended September 30, 2013 is primarily driven by shorter trucking distances to rail terminals as compared to pipeline delivery distances in previous periods and the reversal of a $4.0 million provision recorded in the prior year.

Transportation expenses decreased slightly to $3.82/boe for the nine months ended September 30, 2013, as compared to $3.88/boe for the same period of 2012. The decrease in transportation expenses per barrel of heavy oil for the nine months ended September 30, 2013 is primarily driven by shorter trucking distances to rail terminals as compared to pipeline delivery distances in previous periods, and lower wait times at rail terminals, partially offset by harsh winter conditions which caused delays and re-routings.

Operating Netback

($ per boe except for % and volume)	Three Months Ended September 30 2013	2012	Change	Nine Months Ended September 30 2013	2012	Change
Sales volume (boe/d)	60,262	54,233	11%	56,914	53,584	6%
Operating netback[1]:						
Sales price[2]	$ 73.36	$ 55.70	32%	$ 62.77	$ 56.56	11%
Less:						
Royalties	15.04	9.57	57%	12.27	10.00	23%
Production and operating expenses	13.09	11.44	14%	13.31	11.74	13%
Transportation expenses	3.09	4.52	(32%)	3.82	3.88	(2%)
Operating netback before financial derivatives	$ 42.14	$ 30.17	40%	$ 33.37	$ 30.94	8%
Financial derivatives gain/(loss)[3]	(2.88)	2.06		0.04	1.03	
Operating netback after financial derivatives gain/(loss)	$ 39.26	$ 32.23	22%	$ 33.41	$ 31.97	5%

(1) Operating netback table includes revenues and costs associated with sulphur production.
(2) Sales price is shown net of blending costs and gains (losses) on physical delivery contracts.
(3) 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 for the three months ended September 30, 2013 decreased to $2.2 million from $2.6 million for the same period in 2012 due to a decrease in the expiration of undeveloped land leases, partially offset by an increase in the impairment of evaluation and exploration assets that will not be developed.

Evaluation and exploration expense for the nine months ended September 30, 2013 decreased to $7.7 million from $9.5 million for the same period in 2012 due to a decrease in the expiration of undeveloped land leases, partially offset by an increase in the impairment of evaluation and exploration assets that will not be developed.

Depletion and Depreciation

Depletion and depreciation for the three months ended September 30, 2013 increased to $74.4 million from $71.6 million for the same period in 2012 due to higher production volumes. On a sales-unit basis, the provision for the current quarter was $13.43/boe, as compared to $14.36/boe for the same quarter in 2012. In the third quarter of 2013, we reviewed the groupings of operating areas for depletion purposes, which resulted in a reduction of the estimated depletion rate for the nine months ended September 30, 2013.

Depletion and depreciation for the nine months ended September 30, 2013 increased to $239.5 million from $214.5 million for the same period in 2012. On a sales-unit basis, the provision for the nine months ended September 30, 2013 was $15.41/boe, as compared to $14.61/boe for the same period in 2012. The increase is a result of increased production volumes and higher development costs in certain areas of operation.

General and Administrative Expenses

($ thousands except for % and per boe)	Three Months Ended September 30 2013	2012	Change	Nine Months Ended September 30 2013	2012	Change
General and administrative expenses	$ 10,970	$ 9,914	11%	$ 33,060	$ 32,239	3%
General and administrative expenses per boe	$ 1.98	$ 1.99	(1%)	$ 2.13	$ 2.20	(3%)

General and administrative expenses for the three months ended September 30, 2013 increased to $11.0 million from $9.9 million for the same period in 2012 due to higher salary, technical and professional service costs, partially offset by higher capital and operating recoveries. On a sales-unit basis, general and administrative expenses were essentially unchanged in the third quarter of 2013, as compared to the same period in 2012.

General and administrative expenses for the nine months ended September 30, 2013 increased to $33.1 million from $32.2 million for the same period in 2012 due to higher salary, technical and professional service costs, partially offset by lower legal fees and higher capital and operating recoveries. On a sales-unit basis, general and administrative expenses decreased from $2.20/boe in the first nine months of 2012 to $2.13/boe in the first nine months of 2013 due to increased production.

Share-based Compensation Expense

On January 1, 2011, Baytex adopted a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards may be granted to directors, officers and employees of the Company and its subsidiaries. Concurrent with the adoption of the Share Award Incentive Plan, Baytex ceased making grants under the Common Share Rights Incentive Plan (the "Share Rights Plan").

Compensation expense related to the Share Award Incentive Plan decreased to $8.4 million for the three months ended September 30, 2013 from $8.8 million for the three months ended September 30, 2012, due to increased forfeitures and lower share prices attributed to recent new grants. Compensation expense related to the Share Rights Plan decreased to $0.2 million for the three months ended September 30, 2013, as compared to $1.0 million for the three months ended September 30, 2012, as no new grants have been made under this plan since January 1, 2011.

Compensation expense related to the Share Award Incentive Plan increased to $27.0 million for the nine months ended September 30, 2013, as compared to $26.8 million for the nine months ended September 30, 2012, due to additional grants and the continued vesting of awards outstanding. Compensation expense related to the Share Rights Plan decreased to $0.5 million for the nine months ended September 30, 2013, as compared to $2.1 million for the nine months ended September 30, 2012, as no new grants have been made under this plan since January 1, 2011.

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.

Financing Costs

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for %)	**2013**	2012	Change	**2013**	2012	Change
Bank loan and other	**$ 2,884**	$ 2,488	16%	**$ 7,364**	$ 8,172	(10%)
Long-term debt	**7,755**	8,700	(11%)	**23,149**	20,981	10%
Accretion on asset retirement obligations	**1,817**	1,663	9%	**5,167**	4,942	5%
Debt financing costs	**22**	11	100%	**2,178**	860	153%
Financing costs	**$ 12,478**	$ 12,862	(3%)	**$ 37,858**	$ 34,955	8%

Financing costs for the three months ended September 30, 2013 decreased slightly to $12.5 million, as compared to $12.9 million in the third quarter of 2012, as higher outstanding debt levels were offset by lower interest rates.

Financing costs for the nine months ended September 30, 2013 increased to $37.9 million, as compared to $35.0 million in the first nine months of 2012. The increase in financing costs for the nine months ended

September 30, 2013 was primarily attributable to higher interest rates on borrowings and higher credit facility amendment fees, offset by slightly lower debt levels as compared to nine months ended September 30, 2012.

Foreign Exchange

($ thousands except for % and exchange rates)	Three Months Ended September 30 2013	2012	Change	Nine Months Ended September 30 2013	2012	Change
Unrealized foreign exchange (gain) loss	$ (4,030)	$ (5,346)	(25%)	$ 4,706	$ (3,234)	(246%)
Realized foreign exchange gain	(28)	(902)	(97%)	(3,629)	(1,002)	262%
Foreign exchange (gain) loss	$ (4,058)	$ (6,248)	(35%)	$ 1,077	$ (4,236)	(125%)
CAD/USD exchange rates:						
At beginning of period	1.0512	1.0191		0.9949	1.0170	
At end of period	1.0285	0.9837		1.0285	0.9837	

The unrealized foreign exchange gains and losses for the three and nine months ended September 30, 2013 and 2012 are mainly due to foreign exchange translation of the U.S. dollar denominated debt outstanding and the effect of movement of the Canadian dollar against the U.S. dollar in the period. The U.S. dollar denominated debt is comprised of the US$150 million Series B senior unsecured debentures and, in 2012, the US$180 million portion of the bank loan which was repaid in July 2012.

The unrealized foreign exchange gain of $4.0 million for the third quarter of 2013, as compared to an unrealized gain of $5.3 million for the third quarter of 2012, was mainly the result of the stronger Canadian dollar against the U.S. dollar at both September 30, 2013 (as compared to June 30, 2013) and at September 30, 2012 (as compared to June 30, 2012). The realized foreign exchange gain for the three months ended September 30, 2013 was mainly due to our day-to-day U.S. dollar denominated transactions. The realized foreign exchange gain for the three months ended September 30, 2012 was due to the repayment of the US$180 million bank loan in August 2012, partially offset by losses on our day-to-day U.S. dollar denominated transactions.

The unrealized loss of $4.7 million for the first nine months of 2013, as compared to an unrealized gain of $3.2 million for the first nine months of 2012, was mainly the result of the weaker Canadian dollar against the U.S. dollar at September 30, 2013 (as compared to December 31, 2012) and the stronger Canadian dollar against the U.S. dollar at September 30, 2012 (as compared to December 31, 2011). The realized gain in the nine months ended September 30, 2013 was mainly due to our day-to-day U.S. dollar denominated transactions.

Income Taxes

For the nine months ended September 30, 2013, income tax expense was $40.6 million, consisting of $6.8 million of current income tax recovery and $47.4 million of deferred income tax expense, as compared to $122.8 million for the nine months ended September 30, 2012 consisting of $13.6 million of current income tax and $109.2 million of deferred income tax expense.

When compared to the prior year, the decrease in income tax expense is primarily the result of a decrease in the amount of gain on divestiture of oil and gas properties.

Our U.S. corporate tax returns for the 2012 tax year were filed during the third quarter of 2013 and the recovery of $6.3 million of current income tax reflects a true-up of current taxes previously estimated. We do not expect to incur any cash income tax expense nor receive any additional tax refund during the fourth quarter of 2013.

Net Income

Net income for the three months ended September 30, 2013 was $87.3 million, as compared to net income of $26.8 million for the same period in 2012. The increase in net income was due to higher operating netbacks, offset by realized financial instrument losses in 2013 as compared to gains in 2012 and higher deferred income tax expenses.

Net income for the nine months ended September 30, 2013 was $133.7 million, as compared to $227.0 million for the same period in 2012. The decrease in net income was due to a gain on disposition of U.S. properties of $172.8 million in 2012 which was not repeated in 2013, financial instrument losses in 2013 as compared to gains in 2012 and higher depletion and depreciation, offset by higher operating netbacks.

Other Comprehensive Income

Revenues and expenses of foreign operations are translated to Canadian dollars using average foreign currency exchange rates for the period. Monetary assets and liabilities which form part of the net investment in the foreign operation are translated at the period-end foreign currency exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

The $6.7 million balance of accumulated other comprehensive loss at September 30, 2013 is the sum of a $12.4 million foreign currency translation loss incurred as at December 31, 2012 and a $5.7 million foreign currency translation gain related to the nine months ended September 30, 2013.

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 Dividend Reinvestment Plan ("DRIP")) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate its ability to generate the cash flow necessary to fund dividends and capital investments.

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

	Three Months Ended		Nine Months Ended	
($ thousands except for %)	**September 30, 2013**	September 30, 2012	**September 30, 2013**	September 30, 2012
Cash flow from operating activities	**$ 204,093**	$ 142,368	**$ 459,573**	$ 416,430
Change in non-cash working capital	**1,776**	6,497	**21,334**	16,210
Asset retirement expenditures	**3,944**	1,205	**8,190**	2,353
Financing costs	**(12,478)**	(12,862)	**(37,858)**	(34,955)
Accretion on asset retirement obligations	**1,817**	1,663	**5,167**	4,942
Accretion on debentures and long-term debt	**166**	173	**488**	492
Funds from operations	**$ 199,318**	$ 139,044	**$ 456,894**	$ 405,472
Dividends declared	**$ 82,029**	$ 79,622	**$ 244,420**	$ 236,895
Reinvested dividends	**(20,675)**	(26,982)	**(66,291)**	(76,753)
Cash dividends declared (net of DRIP)	**$ 61,354**	$ 52,640	**$ 178,129**	$ 160,142
Payout ratio	**41%**	57%	**53%**	58%
Payout ratio (net of DRIP)	**31%**	38%	**39%**	39%

Baytex does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of petroleum and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the petroleum and natural gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, a level of judgment is required to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, it is possible that Baytex would be required to reduce or eliminate its dividends in order to fund capital expenditures. There can be no certainty that Baytex will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $61.4 million for the third quarter of 2013 were funded by funds from operations of $199.3 million. Cash dividends declared, net of DRIP participation, of $178.1 million for the first nine months of 2013 were funded by funds from operations of $456.9 million.

LIQUIDITY AND CAPITAL RESOURCES

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 in the short, medium and long-term. 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 from a counterparty.

($ thousands)	September 30, 2013	December 31, 2012
Bank loan	$ 244,651	$ 116,394
Long-term debt[1]	454,275	449,235
Working capital deficiency	57,703	34,197
Total monetary debt	**$ 756,629**	$ 599,826

(1) Principal amount of instruments.

At September 30, 2013 total monetary debt was $756.6 million, as compared to $599.8 million at December 31, 2012. Total credit facilities in place are $850.0 million.

Our wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40.0 million extendible operating loan facility with a chartered bank and an $810.0 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). On June 4, 2013, Baytex Energy reached an agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the extendible syndicated loan facility to $810.0 million (from $660.0 million), (ii) extend the maximum term of the revolving period for both the operating and syndicated loan facilities to four years (from three years) and, (iii) extend the maturity date of both the operating and syndicated loan facilities to June 14, 2017 (from June 14, 2015). The credit facilities contain standard commercial covenants for facilities of this nature. Baytex Energy is in compliance with all such covenants. The credit facilities do not require any mandatory principal payments prior to maturity. Advances (including letters of credit) under the credit 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 LIBOR, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain of our material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, our ability to pay dividends to shareholders may be restricted. A copy of the amended and restated credit agreement (and related amendments) which establishes the credit facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011, July 10, 2012, January 14, 2013 and August 9, 2013).

The weighted average interest rate on the bank loan for the nine months ended September 30, 2013 was 4.80% (year ended December 31, 2012 – 3.95% and nine months ended September 30, 2012 – 3.29%).

On July 19, 2012, we issued $300 million principal amount of Series C senior unsecured debentures bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. Net proceeds of this issue were used to repay a portion of the amount drawn in Canadian currency on Baytex Energy's credit facilities. These debentures are unsecured and are subordinate to Baytex Energy's credit facilities.

On August 26, 2012, we redeemed our 9.15% Series A senior unsecured debentures due August 26, 2016 ($150 million principal amount) at 104.575% of the principal amount. The payment of the redemption price was funded by drawing upon Baytex Energy's credit facilities.

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 debentures and Baytex Energy's credit facilities.

Baytex believes that funds from operations, together with the existing credit facilities, will be sufficient to finance current operations, dividends to the shareholders and planned capital expenditures for the ensuing year. 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 the Company has the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes.

Capital Expenditures

Capital expenditures are summarized as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	2013	2012	2013	2012
Land	$ 1,402	$ 3,813	$ 6,802	$ 10,600
Seismic	94	795	860	2,337
Drilling and completion	69,485	81,534	310,655	246,125
Equipment	50,503	26,935	147,495	92,821
Other	–	49	28	56
Total exploration and development	$ 121,484	$ 113,126	$ 465,840	$ 351,939
Total acquisitions, net of divestitures	2,838	2,160	(41,340)	(302,733)
Total oil and natural gas expenditures	124,322	115,286	424,500	49,206
Other plant and equipment, net	12	2,454	4,732	9,121
Total capital expenditures	$ 124,334	$ 117,740	$ 429,232	$ 58,327

During the three months ended September 30, 2013, Baytex drilled 58.3 net wells, as compared to 47.9 net wells in the three months ended September 30, 2012. During the nine months ended September 30, 2013, Baytex drilled 193.9 net wells, as compared to 142.2 net wells in the nine months ended September 30, 2012. Over the first nine months of 2013, capital investment activity has progressed as planned in our key development areas. Our thermal development projects are proceeding on schedule with facility construction underway at both our 15-well cyclic steam stimulation module at Cliffdale and our Gemini steam-assisted gravity drainage pilot project.

Shareholders' Capital

Baytex is authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. Baytex establishes the rights and terms of preferred shares upon issuance. As at October 25, 2013 the Company had 124,892,741 common shares and no preferred shares issued and outstanding.

Contractual Obligations

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations on an ongoing manner. A significant portion of these obligations will be funded with funds from operations. These obligations as of September 30, 2013, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 225,230**	$ 225,230	$ –	$ –	$ –
Dividends payable to shareholders	**27,389**	27,389	–	–	–
Bank loan[1]	**244,651**	–	–	244,651	–
Long-term debt[2]	**454,275**	–	–	–	454,275
Operating leases	**41,680**	6,351	12,754	12,498	10,077
Processing agreements	**27,229**	1,708	4,367	4,431	16,723
Transportation agreements	**69,661**	4,070	18,542	17,422	29,627
Total	**$1,090,115**	$ 264,748	$ 35,663	$ 279,002	$ 510,702

(1) The bank loan is a covenant-based revolving loan that is extendible annually for a one, two, three or four year period (subject to a maximum four-year term at any time). Unless extended, the revolving period will end on June 14, 2017, with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex is exposed to a number of financial risks, including market risk, liquidity risk and credit risk. 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 managed by Baytex through a series of derivative contracts intended to manage the volatility of its operating cash flow. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its 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. Baytex manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis.

A summary of the risk management contracts in place as at September 30, 2013 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2013			2012				2011
($ thousands, except per common share amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Gross revenues	**422,791**	341,011	272,945	292,095	299,786	284,248	343,355	367,813
Net income	**87,331**	36,192	10,149	31,620	26,773	157,280	42,958	57,780
Per common share – basic	**0.70**	0.29	0.08	0.26	0.22	1.32	0.36	0.49
Per common share – diluted	**0.70**	0.29	0.08	0.26	0.22	1.30	0.36	0.48

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: crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our business strategies, plans and objectives; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; 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; 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: 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; 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; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period 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: 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 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, 2012, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.*

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast 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, 2013	December 31, 2012
ASSETS		
Current assets		
Cash	$ 315	$ 1,837
Trade and other receivables	194,195	170,972
Crude oil inventory	406	1,363
Financial derivatives	10,577	20,167
	205,493	194,339
Non-current assets		
Financial derivatives	1,270	–
Exploration and evaluation assets (note 3)	177,395	240,015
Oil and gas properties (note 4)	2,288,408	2,037,576
Other plant and equipment	30,848	28,392
Goodwill	37,755	37,755
	$ 2,741,169	$ 2,538,077
LIABILITIES		
Current liabilities		
Trade and other payables	$ 225,230	$ 181,558
Dividends payable to shareholders	27,389	26,811
Financial derivatives	20,021	10,826
	272,640	219,195
Non-current liabilities		
Bank loan (note 5)	244,651	116,394
Long-term debt (note 6)	446,659	441,195
Asset retirement obligations (note 7)	245,489	265,520
Deferred income tax liability	234,557	189,160
Financial derivatives	1,108	7,201
	1,445,104	1,238,665
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 8)	1,969,018	1,860,358
Contributed surplus	58,616	65,615
Accumulated other comprehensive loss	(6,722)	(12,462)
Deficit	(724,847)	(614,099)
	1,296,065	1,299,412
	$ 2,741,169	$ 2,538,077

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands of Canadian dollars, except per common share amounts) *(unaudited)*	**2013**	2012	**2013**	2012
Revenues, net of royalties (note 12)	**$ 339,395**	$ 252,028	**$ 846,063**	$ 780,617
Expenses				
Production and operating	**72,565**	57,093	**206,780**	172,347
Transportation and blending	**33,178**	44,426	**120,754**	153,953
Exploration and evaluation (note 3)	**2,160**	2,553	**7,737**	9,483
Depletion and depreciation	**74,397**	71,642	**239,507**	214,534
General and administrative	**10,970**	9,914	**33,060**	32,239
Share-based compensation (note 9)	**8,586**	9,759	**27,524**	28,960
Financing costs (note 13)	**12,478**	12,862	**37,858**	34,955
Loss (gain) on financial derivatives (note 15)	**19,065**	(1,434)	**18,515**	(47,956)
Foreign exchange (gain) loss (note 14)	**(4,058)**	(6,248)	**1,077**	(4,236)
(Gain) loss on divestiture of oil and gas properties	**(38)**	2,654	**(20,989)**	(172,752)
Charge on redemption of long-term debt	**–**	9,261	**–**	9,261
	229,303	212,482	**671,823**	430,788
Net income before income taxes	**110,092**	39,546	**174,240**	349,829
Income tax expense (note 11)				
Current income tax (recovery) expense	**(6,821)**	(3,035)	**(6,821)**	13,629
Deferred income tax expense	**29,582**	15,808	**47,389**	109,189
	22,761	12,773	**40,568**	122,818
Net income attributable to shareholders	**$ 87,331**	$ 26,773	**$ 133,672**	$ 227,011
Other comprehensive income				
Foreign currency translation adjustment	**(5,603)**	(14,445)	**5,740**	(12,877)
Comprehensive income	**$ 81,728**	$ 12,328	**$ 139,412**	$ 214,134
Net income per common share (note 10)				
Basic	**$ 0.70**	$ 0.22	**$ 1.08**	$ 1.90
Diluted	**$ 0.70**	$ 0.22	**$ 1.07**	$ 1.87
Weighted average common shares (note 10)				
Basic	**124,172**	120,469	**123,318**	119,476
Diluted	**125,570**	121,893	**124,860**	121,291

See accompanying notes to the condensed 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, 2011	$ 1,680,184	$ 85,716	$ (3,546)	$ (555,620)	**$ 1,206,734**
Dividends to shareholders	–	–	–	(236,895)	**(236,895)**
Exercise of share rights	47,320	(28,857)	–	–	**18,463**
Vesting of share awards	20,048	(20,048)	–	–	**–**
Share-based compensation	–	28,960	–	–	**28,960**
Issued pursuant to dividend reinvestment plan	75,407	–	–	–	**75,407**
Comprehensive income for the period	–	–	(12,877)	227,011	**214,134**
Balance at September 30, 2012	$ 1,822,959	$ 65,771	$ (16,423)	$ (565,504)	**$ 1,306,803**
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**

(1) Contributed surplus is comprised of share-based compensation.

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands of Canadian dollars) (unaudited)	2013	2012	2013	2012
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income for the period	$ 87,331	$ 26,773	$ 133,672	$ 227,011
Adjustments for:				
Share-based compensation (note 9)	8,586	9,759	27,524	28,960
Unrealized foreign exchange (gain) loss (note 14)	(4,030)	(5,346)	4,706	(3,234)
Exploration and evaluation	2,160	2,553	7,737	9,483
Depletion and depreciation	74,397	71,642	239,507	214,534
Unrealized (gain) loss on financial derivatives (note 15)	(653)	7,139	11,693	(36,043)
(Gain) loss on divestitures of oil and gas properties	(38)	2,654	(20,989)	(172,752)
Current income tax expense on divestiture	–	(3,035)	–	13,629
Deferred income tax expense	29,582	15,808	47,389	109,189
Charge on redemption of long-term debt	–	9,261	–	9,261
Financing costs (note 13)	12,478	12,862	37,858	34,955
Change in non-cash working capital	(1,776)	(6,497)	(21,334)	(16,210)
Asset retirement obligations settled (note 7)	(3,944)	(1,205)	(8,190)	(2,353)
	204,093	142,368	459,573	416,430
Financing activities				
Payment of dividends	(61,437)	(51,458)	(177,117)	(160,813)
Increase (decrease) in bank loan	19,217	(214,035)	128,257	(130,175)
Proceeds from issuance of long-term debt	–	293,761	–	293,761
Redemption of long-term debt	–	(156,863)	–	(156,863)
Issuance of common shares (note 8)	2,111	3,399	7,412	18,463
Interest paid	(18,754)	(14,169)	(40,753)	(32,397)
	(58,863)	(139,365)	(82,201)	(168,024)
Investing activities				
Additions to exploration and evaluation assets (note 3)	(2,545)	(4,402)	(7,608)	(12,096)
Additions to oil and gas properties (note 4)	(118,939)	(108,724)	(458,232)	(339,843)
Property acquisitions	18	(958)	(36)	(13,467)
Corporate acquisition	(3,586)	–	(3,586)	–
Proceeds from divestiture of oil and gas properties	730	(1,202)	44,962	316,200
Current income tax expense on divestiture	–	3,035	–	(13,629)
Additions to other plant and equipment, net of disposals	(12)	(2,454)	(4,732)	(9,121)
Change in non-cash working capital	(22,850)	3,716	52,085	20,558
	(147,184)	(110,989)	(377,147)	(51,398)
Impact of foreign currency translation on cash balances	(85)	(6,750)	(1,747)	(7,125)
Change in cash	(2,039)	(114,736)	(1,522)	189,883
Cash, beginning of period	2,354	312,466	1,837	7,847
Cash, end of period	$ 315	$ 197,730	$ 315	$ 197,730

See accompanying notes to the condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at September 30, 2013 and December 31, 2012 and for the three and nine months ended September 30, 2013 and 2012

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

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards ("IAS") 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 ("IFRS") and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2012. The Company's accounting policies are unchanged compared to December 31, 2012 except as listed in note 3 "Changes in Accounting Policies" of the consolidated financial statements as of March 31, 2013. The use of estimates and judgments is also consistent with the December 31, 2012 consolidated financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on October 29, 2013.

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. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2011	**$ 129,774**
Capital expenditures	13,406
Property acquisitions	135,772
Exploration and evaluation expense	(12,202)
Transfer to oil and gas properties	(3,902)
Divestitures	(22,074)
Foreign currency translation	(759)
As at December 31, 2012	**$ 240,015**
Capital expenditures	7,608
Exploration and evaluation expense	(7,737)
Transfer to oil and gas properties	(62,596)
Divestitures	(1,251)
Foreign currency translation	1,356
As at September 30, 2013	**$ 177,395**

4. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2011	**$ 2,471,419**
Capital expenditures	405,219
Property acquisitions	8,270
Transferred from exploration and evaluation assets	3,902
Change in asset retirement obligations	5,429
Divestitures	(133,447)
Foreign currency translation	(2,483)
As at December 31, 2012	**$ 2,758,309**
Capital expenditures	458,232
Property acquisitions	36
Corporate acquisition	100
Transferred from exploration and evaluation assets	62,596
Change in asset retirement obligations	(17,056)
Divestitures	(32,913)
Foreign currency translation	7,418
As at September 30, 2013	**$ 3,236,722**

Accumulated depletion	
As at December 31, 2011	**$ 439,259**
Depletion for the period	294,623
Divestitures	(13,089)
Foreign currency translation	(60)
As at December 31, 2012	**$ 720,733**
Depletion for the period	237,199
Divestitures	(10,191)
Foreign currency translation	573
As at September 30, 2013	**$ 948,314**

Carrying value	
As at December 31, 2012	**$ 2,037,576**
As at September 30, 2013	**$ 2,288,408**

5. BANK LOAN

As at	September 30, 2013	December 31, 2012
Bank loan	$ 244,651	$ 116,394

The Company's wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40.0 million extendible operating loan facility with a chartered bank and an $810.0 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). On June 4, 2013, Baytex Energy reached agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the extendible syndicated loan facility to $810.0 million (from $660.0 million), (ii) extend the maximum term of the revolving period for both the operating and syndicated loan facilities to four years (from three years) and, (iii) extend the maturity date of both the operating and syndicated loan facilities to June 14, 2017 (from June 14, 2015). The credit facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments prior to maturity. Advances (including letters of credit) under the credit 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. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain of its material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, Baytex's ability to pay dividends to its shareholders may be restricted.

Financing costs for nine months ended September 30, 2013 include credit facility amendment fees of $2.1 million ($0.8 million for the nine months ended September 30, 2012). The weighted average interest rate on the bank loan for the nine months ended September 30, 2013 was 4.80% (3.29% for the nine months ended September 30, 2012).

6. LONG-TERM DEBT

As at	September 30, 2013	December 31, 2012
6.75% Series B senior unsecured debentures (US$150,000 – principal) due February 17, 2021	$ 152,421	$ 147,305
6.625% Series C senior unsecured debentures (Cdn$300,000 – principal) due July 19, 2022	294,238	293,890
	$ 446,659	$ 441,195

Accretion expense on debentures of $0.2 million has been recorded in financing costs on long-term debt for the three months ended September 30, 2013 (three months ended September 30, 2012 – $0.2 million) and $0.5 million for the nine months ended September 30, 2013 (nine months ended September 30, 2012 – $0.5 million).

7. ASSET RETIREMENT OBLIGATIONS

	September 30, 2013	December 31, 2012
Balance, beginning of period	$ 265,520	$ 260,411
Liabilities incurred	12,332	7,092
Liabilities settled	(8,190)	(6,905)
Liabilities acquired	–	1,037
Liabilities divested	(1,294)	(2,372)
Accretion	5,167	6,631
Change in estimate(1)	(28,094)	(328)
Foreign currency translation	48	(46)
Balance, end of period	$ 245,489	$ 265,520

(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.

8. SHAREHOLDERS' CAPITAL

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, 2013, 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, 2011	**117,893**	**$ 1,680,184**
Issued on exercise of share rights	1,366	21,873
Transfer from contributed surplus on exercise of share rights	–	36,667
Transfer from contributed surplus on vesting and conversion of share awards	403	20,118
Issued pursuant to dividend reinvestment plan	2,206	101,516
Balance, December 31, 2012	**121,868**	**$ 1,860,358**
Issued on exercise of share rights	498	7,412
Transfer from contributed surplus on exercise of share rights	–	12,184
Transfer from contributed surplus on vesting and conversion of share awards	499	22,339
Issued pursuant to dividend reinvestment plan	1,632	66,725
Balance, September 30, 2013	**124,497**	**$ 1,969,018**

Monthly dividends of $0.22 per common share were declared by the Company during the three and nine months ended September 30, 2013 for total dividends declared of $82.0 million ($61.4 million net of dividend reinvestment) and $244.4 million ($178.1 million net of dividend reinvestment), respectively.

9. EQUITY BASED PLANS

Share Award Incentive Plan

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

The Company recorded compensation expense related to the share awards of $8.4 million for the three months ended September 30, 2013 (three months ended September 30, 2012 – $8.8 million) and $27.0 million for the nine months ended September 30, 2013 (nine months ended September 30, 2012 – $26.8 million).

The fair value of share awards is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate, which has been estimated at 4.6% of outstanding share awards. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. The estimated weighted average fair value for share awards at the measurement date is $42.91 per restricted award and performance award granted during the nine months ended September 30, 2013 (nine months ended September 30, 2012 – $51.52 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, 2011	**365**	**229**	**594**
Granted	370	306	676
Vested and converted to common shares	(133)	(130)	(263)
Forfeited	(36)	(17)	(53)
Balance, December 31, 2012	**566**	**388**	**954**
Granted	437	374	811
Vested and converted to common shares	(198)	(124)	(322)
Forfeited	(72)	(41)	(113)
Balance, September 30, 2013	**733**	**597**	**1,330**

Share Rights Plan

As a result of the conversion of the legal structure of the Company's predecessor, Baytex Energy Trust (the "Trust"), from an income trust to a corporation at year-end 2010, Baytex adopted a Common Share Rights Incentive Plan (the "Share Rights Plan") to facilitate the exchange of the outstanding unit rights (granted under the Unit Rights Plan of the Trust) for share rights.

As a result of the adoption of the Share Award Incentive Plan (as described above) effective January 1, 2011, no further grants will be made under the Share Rights Plan. The Share Rights Plan will remain in place until such time as all outstanding share rights have been exercised, canceled or expired.

Under the Share Rights Plan, share rights have a maximum term of five years and vest and become exercisable as to one-third on each of the first, second and third anniversaries of the grant date. Each share right entitles the holder thereof to acquire a common share upon payment of the exercise price, which may be reduced to account for future dividends (subject to certain performance criteria).

Baytex recorded compensation expense related to the share rights under the Share Rights Plan of $0.2 million for the three months ended September 30, 2013 (three months ended September 30, 2012 – $1.0 million) and $0.5 million for the nine months ended September 30, 2013 (nine months ended September 30, 2012 – $2.1 million).

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

	Number of share rights *(000s)*	Weighted average exercise price
Balance, December 31, 2011[1]	**2,971**	**$ 16.98**
Exercised[2]	(1,366)	16.01
Forfeited[1]	(80)	21.27
Balance, December 31, 2012[1]	**1,525**	**$ 16.79**
Exercised[2]	(498)	15.07
Forfeited[1]	(5)	29.60
Balance, September 30, 2013[1]	**1,022**	**$ 15.89**

(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.

The following table summarizes information about the share rights outstanding at September 30, 2013:

	Exercise Prices Applying Original Grant Price					Exercise Prices Applying Original Grant Price Reduced for Dividends and Distributions Subsequent to Grant Date				
PRICE RANGE	Number Outstanding at September 30, 2013 (000s)	Weighted Average Grant Price	Weighted Average Remaining Term (years)	Number Exercisable at September 30, 2013 (000s)	Weighted Average Exercise Price	Number Outstanding at September 30, 2013 (000s)	Weighted Average Exercise Price	Weighted Average Remaining Term (years)	Number Exercisable at September 30, 2013 (000s)	Weighted Average Exercise Price
$2.26 to $8.75	–	$ –	–	–	$ –	240	$ 6.74	0.1	240	$ 6.74
$8.76 to $15.25	6	12.67	0.4	6	12.67	114	12.88	0.9	114	12.88
$15.26 to $21.75	274	18.33	0.1	274	18.33	593	18.58	1.2	593	18.58
$21.76 to $28.25	687	27.04	1.2	687	27.04	45	26.55	1.4	45	26.55
$28.26 to $34.75	32	31.83	1.5	32	31.83	28	31.38	1.8	22	31.71
$34.76 to $40.87	23	37.50	2.0	16	37.12	2	38.83	2.2	1	38.81
$2.26 to $40.87	1,022	$ 25.00	0.9	1,015	$ 24.91	1,022	$ 15.89	0.9	1,015	$ 15.79

10. NET INCOME PER SHARE

Baytex calculates basic income per share based on the net income attributable to shareholders and a weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted and share rights were exercised. The treasury stock method is used to determine the dilutive effect of share awards and share rights whereby the potential conversion of share awards, the estimated proceeds from the exercise of share rights and the amount of compensation expense, if any, attributed to future services not yet recognized, are assumed to be used to purchase common shares at the average market price during the periods.

	Three Months Ended September 30, 2013			Three Months Ended September 30, 2012		
	Net income	Common shares (000s)	Net income per share	Net income	Common shares (000s)	Net income per share
Net income – basic	$ 87,331	124,172	$ 0.70	$ 26,773	120,469	$ 0.22
Dilutive effect of share awards	–	937	–	–	958	–
Dilutive effect of share rights	–	461	–	–	466	–
Net income – diluted	$ 87,331	125,570	$ 0.70	$ 26,773	121,893	$ 0.22

	Nine Months Ended September 30, 2013			Nine Months Ended September 30, 2012		
	Net income	Common shares (000s)	Net income per share	Net income	Common shares (000s)	Net income per share
Net income – basic	$ 133,672	123,318	$ 1.08	$ 227,011	119,476	$ 1.90
Dilutive effect of share awards	–	1,027	–	–	1,214	–
Dilutive effect of share rights	–	515	–	–	601	–
Net income – diluted	$ 133,672	124,860	$ 1.07	$ 227,011	121,291	$ 1.87

11. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2013	2012
Net income before income taxes	$ 174,240	$ 349,829
Expected income taxes at the statutory rate of 25.51% (2012 – 25.45%)[(1)]	44,449	89,031
Increase (decrease) in income taxes resulting from:		
Share-based compensation	7,020	7,369
Effect of rate adjustments for foreign jurisdictions	(4,067)	22,357
Effect of change in opening tax pool balances	(393)	3,680
Remeasurement of deferred tax assets	(6,441)	–
Other	–	381
Income tax expense	$ 40,568	$ 122,818

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

12. REVENUES

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	2012	2013	2012
Petroleum and natural gas revenues	$ 422,068	$ 298,953	$ 1,033,927	$ 924,740
Royalty charges	(83,396)	(47,758)	(190,684)	(146,772)
Royalty income	723	833	2,820	2,649
Revenues, net of royalties	$ 339,395	$ 252,028	$ 846,063	$ 780,617

13. FINANCING COSTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	2012	2013	2012
Bank loan and other	$ 2,884	$ 2,488	$ 7,364	$ 8,172
Long-term debt	7,755	8,700	23,149	20,981
Accretion on asset retirement obligations	1,817	1,663	5,167	4,942
Debt financing costs	22	11	2,178	860
Financing costs	$ 12,478	$ 12,862	$ 37,858	$ 34,955

14. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	2012	2013	2012
Unrealized foreign exchange (gain) loss	$ (4,030)	$ (5,346)	$ 4,706	$ (3,234)
Realized foreign exchange gain	(28)	(902)	(3,629)	(1,002)
Foreign exchange (gain) loss	$ (4,058)	$ (6,248)	$ 1,077	$ (4,236)

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Foreign Currency Risk

At September 30, 2013, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	October 2013	US$1.00 million	1.0433	(1)
Monthly average collar	October to December 2013	US$1.00 million	1.0000 - 1.0720	(1)
Monthly average collar	October to December 2013	US$1.00 million	1.0100 - 1.0725	(1)
Monthly average collar	October to December 2013	US$1.00 million	1.0200 - 1.0575	(1)
Monthly average collar	October to December 2013	US$1.00 million	1.0200 - 1.0655	(1)
Monthly average collar	October to December 2013	US$1.00 million	1.0250 - 1.0702	(1)
Monthly average collar	October to December 2013	US$2.00 million	1.0300 - 1.0650	(1)
Monthly forward spot sale	October to December 2013	US$19.00 million	1.0361	(2)
Monthly average rate forward	October to December 2013	US$6.25 million	1.0414	(1)
Monthly average collar	October to December 2013	US$0.25 million	0.9700 - 1.0310	(1)
Monthly average rate forward	October 2013 to December 2014	US$2.00 million	1.0388	(2)
Monthly average rate forward	January to December 2014	US$0.50 million	1.0582	(1)
Monthly average collar	January to December 2014	US$1.00 million	1.0300 - 1.0600	(1)
Monthly average collar	January to December 2014	US$0.50 million	1.0350 - 1.1100	(1)(3)
Monthly average collar	January to December 2014	US$0.50 million	1.0375 - 1.1100	(1)(3)
Monthly average collar	January to December 2014	US$1.00 million	1.0400 - 1.1100	(1)(3)
Monthly average collar	January to December 2014	US$1.00 million	1.0430 - 1.1100	(1)(3)
Monthly average collar	January to December 2014	US$1.00 million	1.0450 - 1.1100	(1)(3)
Monthly average collar	January to December 2014	US$0.50 million	1.0500 - 1.1100	(1)(3)
Sold call option	January to December 2014	US$1.00 million	1.0300	(1)(4)
Sold call option	January to December 2014	US$1.00 million	1.0320	(1)(4)
Sold call option	January to December 2014	US$2.00 million	1.0450	(1)(4)
Sold call option	January to December 2014	US$2.00 million	1.0500	(1)(4)
Sold call option	January to December 2014	US$1.00 million	1.0530	(1)(4)
Sold call option	January to December 2014	US$1.00 million	1.0547	(1)(4)
Sold call option	July to December 2014	US$6.00 million	1.0500	(1)(4)
Sold call option	July to December 2014	US$4.00 million	1.0520	(1)(4)

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

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

(3) Monthly sales 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.

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, 2013	December 31, 2012	**September 30, 2013**	December 31, 2012
U.S. dollar denominated	**US$115,089**	US$124,048	**US$192,971**	US$201,980

Interest Rate Risk

As at September 30, 2013, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay fixed, receive floating	October 2013 to September 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, receive floating	October 2013 to September 2014	US$90.0 million	4.39%	3-month LIBOR

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, 2013, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	October to November 2013	1,000 bbl/d	US$100.00	WTI
Fixed – Sell	October to December 2013	25,500 bbl/d	US$99.44	WTI
Fixed – Sell	October 2013 to March 2014	2,000 bbl/d	US$101.88	WTI
Fixed – Sell	December 2013 to March 2014	1,000 bbl/d	US$98.50	WTI
Sold call option(2)	December 2013 to March 2014	1,000 bbl/d	US$101.00	WTI
Fixed – Sell	January to March 2014	8,500 bbl/d	US$99.65	WTI
Sold call option(2)	January to March 2014	1,500 bbl/d	US$100.00	WTI
Fixed – Sell	January to June 2014	1,750 bbl/d	US$100.36	WTI
Sold call option(2)	January to June 2014	1,000 bbl/d	US$104.70	WTI
Sold call option(2)	January to June 2014	1,000 bbl/d	US$99.50	WTI
Sold call option(2)	January to June 2014	1,000 bbl/d	US$99.00	WTI
Fixed – Sell	January to September 2014	1,000 bbl/d	US$97.98	WTI
Fixed – Sell	January to December 2014	3,500 bbl/d	US$95.43	WTI
Fixed – Buy	January to December 2014	380 bbl/d	US$101.06	WTI
Fixed – Sell	April to June 2014	5,000 bbl/d	US$100.16	WTI
Sold call option(2)	April to September 2014	2,000 bbl/d	US$100.00	WTI
Fixed – Sell	July to September 2014	2,000 bbl/d	US$99.13	WTI
Fixed – Sell	July to December 2014	3,000 bbl/d	US$95.40	WTI
Sold call option(2)	July to December 2014	1,000 bbl/d	US$95.00	WTI
Sold call option(2)	July 2014 to June 2015	4,000 bbl/d	US$95.00	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.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	October 2013	2,500 mmBtu/d	US$4.16	NYMEX
Price collar	October 2013	10,000 mmBtu/d	US$3.50 – US$3.75	NYMEX
Fixed – Sell	October to December 2013	2,000 GJ/d	$3.37	AECO
Fixed – Sell	October to December 2013	5,000 mmBtu/d	US$4.05	NYMEX
Basis swap	October to December 2013	2,000 mmBtu/d	NYMEX less US$0.375	AECO
Basis swap	October to December 2013	1,000 mmBtu/d	NYMEX less US$0.388	AECO
Basis swap	October to December 2013	2,000 mmBtu/d	NYMEX less US$0.428	AECO
Price collar	November 2013 to March 2014	10,000 mmBtu/d	US$4.00 – US$4.50	NYMEX
Price collar	November 2013 to March 2014	2,500 mmBtu/d	US$4.20 – US$4.60	NYMEX
Fixed – Sell	January to December 2014	2,000 mmBtu/d	US$4.45	NYMEX
Sold call option	January to December 2014	2,000 mmBtu/d	US$4.45	NYMEX
Fixed – Sell	April 2014 to March 2015	10,000 mmBtu/d	US$4.08	NYMEX

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	2012	**2013**	2012
Realized loss (gain) on financial derivatives	**$ 19,718**	$ (8,573)	**$ 6,822**	$ (11,913)
Unrealized (gain) loss on financial derivatives	**(653)**	7,139	**11,693**	(36,043)
Loss (gain) on financial derivatives	**$ 19,065**	$ (1,434)	**$ 18,515**	$ (47,956)

Subsequent to September 30, 2013, Baytex added the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Basis swap	January to December 2014	2,000 bbl/d	WTI less US$22.90	WCS
Fixed – Sell	April to September 2014	500 bbl/d	US$100.00	WTI
Fixed – Sell	July to September 2014	1,000 bbl/d	US$100.25	WTI
Sold call option(2)	July 2014 to June 2015	1,000 bbl/d	US$96.00	WTI
Sold call option(2)	January to December 2015	1,000 bbl/d	US$92.00	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.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Basis swap	November 2013 to March 2014	10,000 mmBtu/d	NYMEX less US$0.360	AECO
Basis swap	November 2013 to March 2014	5,000 mmBtu/d	NYMEX less US$0.370	AECO

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

Physical Delivery Contracts

As at September 30, 2013, 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	Weighted Average Price/Unit(1)
WCS Blend	October 2013 to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	October to December 2013	2,000 bbl/d	WTI less US$21.50
WCS Blend	October to December 2013	2,750 bbl/d	WTI × 80.00%
WCS Blend	October to December 2013	2,750 bbl/d	WTI less US$21.00

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

Condensate (diluent)	Period	Volume	Price/Unit
Fixed – Buy	October to December 2013	160 bbl/d	WTI plus US$3.10

At September 30, 2013, 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 2013	11,700 bbl/d
Raw bitumen	January to March 2014	4,000 bbl/d
Raw bitumen	April to June 2014	3,675 bbl/d

16. 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"), to replace a Short Form Base Shelf Prospectus filed on August 4, 2011. 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 (Canadian).

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.

Pursuant to the credit agreement governing Baytex Energy's credit facilities, Baytex Energy and its subsidiaries are prohibited from paying dividends to their shareholders that would have, or would reasonably be expected to have, a material adverse effect or would adversely affect or impair the ability or capacity of Baytex Energy to pay or fulfill any of its obligations under the credit agreement. In addition, Baytex Energy may not permit any of its subsidiaries to pay any dividends during the continuance of a default or event of default under the credit agreement.

The following tables present condensed interim unaudited consolidating financial information as at September 30, 2013, and December 31, 2012 and for the three and nine months ended September 30, 2013 and 2012 for: 1) Baytex, on a stand-alone basis, 2) Guarantor subsidiaries, on a stand-alone basis, 3) non-guarantor subsidiaries, on a stand-alone basis and 4) Baytex, on a consolidated basis.

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
As at September 30, 2013					
Current assets	$ 2	$ 205,185	$ 306	$ –	$ 205,493
Intercompany advances and investments	1,613,099	(464,020)	78,862	(1,227,941)	–
Non-current assets	2,435	2,533,241	–	–	2,535,676
Current liabilities	32,603	239,795	242	–	272,640
Bank loan and long-term debt	446,659	244,651	–	–	691,310
Asset retirement obligation and other non-current liabilities	$ –	$ 481,154	$ –	$ –	$ 481,154
As at December 31, 2012					
Current assets	$ 4	$ 194,086	$ 249	$ –	$ 194,339
Intercompany advances and investments	1,756,923	(555,059)	70,298	(1,272,162)	–
Non-current assets	2,435	2,341,303	–	–	2,343,738
Current liabilities	39,478	179,503	214	–	219,195
Bank loan and long-term debt	441,195	116,394	–	–	557,589
Asset retirement obligation and other non-current liabilities	$ –	$ 461,881	$ –	$ –	$ 461,881

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
For the nine months ended September 30, 2013					
Revenues, net of royalties	$ 22,741	$ 847,188	$ 17,370	$ (41,236)	$ 846,063
Production, operation and exploration	–	214,517	–	–	214,517
Transportation and blending	–	120,754	–	–	120,754
General, administrative and unit-based compensation	1,125	60,511	73	(1,125)	60,584
Financing, derivatives, foreign exchange and other (gains)/losses	5,559	71,024	(11)	(40,111)	36,461
Depletion and depreciation	–	239,507	–	–	239,507
Income tax expense	–	40,568	–	–	40,568
Net income (loss)	$ 16,057	$ 100,307	$ 17,308	$ –	$ 133,672
For the three months ended September 30, 2013					
Revenues, net of royalties	$ 8,439	$ 340,550	$ 4,731	$ (14,325)	$ 339,395
Production, operation and exploration	–	74,725	–	–	74,725
Transportation and blending	–	33,178	–	–	33,178
General, administrative and unit-based compensation	1,155	19,556	–	(1,155)	19,556
Financing, derivatives, foreign exchange and other (gains)/losses	(18,315)	58,942	(10)	(13,170)	27,447
Depletion and depreciation	–	74,397	–	–	74,397
Income tax expense	–	22,761	–	–	22,761
Net income (loss)	$ 25,599	$ 56,991	$ 4,741	$ –	$ 87,331
For the nine months ended September 30, 2012					
Revenues, net of royalties	$ 20,386	$ 781,743	$ 13,766	$ (35,278)	$ 780,617
Production, operation and exploration	–	181,830	–	–	181,830
Transportation and blending	–	153,953	–	–	153,953
General, administrative and share-based compensation	1,126	61,062	137	(1,126)	61,199
Financing, derivatives, foreign exchange and other (gains)/losses	25,130	(171,709)	3	(34,152)	(180,728)
Depletion and depreciation	–	214,534	–	–	214,534
Income tax expense	–	122,818	–	–	122,818
Net income (loss)	$ (5,870)	$ 219,255	$ 13,626	$ –	$ 227,011
For the three months ended September 30, 2012					
Revenues, net of royalties	$ 8,678	$ 252,528	$ 5,442	$ (14,620)	$ 252,028
Production, operation and exploration	–	59,646	–	–	59,646
Transportation and blending	–	44,426	–	–	44,426
General, administrative and share-based compensation	500	19,662	11	(500)	19,673
Financing, derivatives, foreign exchange and other (gains)/losses	12,597	18,618	–	(14,120)	17,095
Depletion and depreciation	–	71,642	–	–	71,642
Income tax expense	–	12,773	–	–	12,773
Net income (loss)	$ (4,419)	$ 25,761	$ 5,431	$ –	$ 26,773

(thousands of Canadian dollars)		Baytex		Guarantor Subsidiaries		Non-guarantor Subsidiaries		Consolidation Adjustments		Total Consolidated
For the nine months ended September 30, 2013										
Cash provided by (used in):										
Operating activities	$	21,677	$	422,574	$	15,322	$	–	$	459,573
Payment of dividends		(177,117)		–		–		–		(177,117)
Decrease in bank loan		–		128,257		–		–		128,257
Change in intercompany loans		178,347		(173,385)		(4,962)		–		–
Increase in equity		7,412		–		–		–		7,412
Interest paid		(30,319)		175		(10,609)		–		(40,753)
Financing activities		(21,677)		(44,953)		(15,571)		–		(82,201)
Additions to exploration and evaluation assets		–		(7,608)		–		–		(7,608)
Additions to oil and gas properties		–		(458,232)		–		–		(458,232)
Property acquisition		–		(36)		–		–		(36)
Corporate acquisition		–		(3,586)		–		–		(3,586)
Proceeds from divestitures		–		44,962		–		–		44,962
Additions to other plant and equipment, net of disposals		–		(4,732)		–		–		(4,732)
Change in non-cash working capital		–		52,085		–		–		52,085
Investing activities		–		(377,147)		–		–		(377,147)
Impact of foreign currency translation on cash balances	$	–	$	(1,747)	$	–	$	–	$	(1,747)
For the nine months ended September 30, 2012										
Cash provided by (used in):										
Operating activities	$	7,764	$	397,897	$	10,769	$	–	$	416,430
Payment of dividends		(160,813)		–		–		–		(160,813)
Increase in bank loan		–		(130,175)		–		–		(130,175)
Proceeds from issuance of long-term debt		293,761		–		–		–		293,761
Redemption of long-term debt		(156,863)		–		–		–		(156,863)
Change in intercompany loans		9,546		96,721		(106,267)		–		–
Increase in investments		–		(106,267)		–		106,267		–
Increase in equity		18,463		–		106,267		(106,267)		18,463
Interest paid		(11,858)		(9,770)		(10,769)		–		(32,397)
Financing activities		(7,764)		(149,491)		(10,769)		–		(168,024)
Additions to exploration and evaluation assets		–		(12,096)		–		–		(12,096)
Additions to oil and gas properties		–		(339,843)		–		–		(339,843)
Property acquisitions		–		(13,467)		–		–		(13,467)
Proceeds from divestitures		–		316,200		–		–		316,200
Current income tax expense on divestiture				(13,629)						(13,629)
Additions to other plant and equipment, net of disposals		–		(9,121)		–		–		(9,121)
Change in non-cash working capital		–		20,558		–		–		20,558
Investing activities		–		(51,398)		–		–		(51,398)
Impact of foreign currency translation on cash balances	$	–	$	(1,747)	$	–	$	–	$	(1,747)

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
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
Executive Chairman
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
Bank of Nova Scotia
Barclays Bank PLC
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank
Wells Fargo Bank

OFFICERS

Raymond T. Chan
Executive Chairman

James L. Bowzer
President and Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Daniel G. Anderson
Vice President, U.S. Business Unit

Kendall D. Arthur
Vice President,
Saskatchewan Business Unit

Geoffrey J. Darcy
Vice President, Marketing

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

Brian G. Ector
Vice President, Investor Relations

Cameron A. Hercus
Vice President, Corporate Development

Timothy R. Morris
Vice President, U.S. Business Development

Richard P. Ramsay
Vice President, Alberta/B.C. Business Unit

Gregory A. Sawchenko
Vice President, Land

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