BAYTEX ENERGY CORP.

Q3 REPORT

2012

SUMMARY

- Produced record quarterly production of 54,381 boe/d (88% oil and NGL) in Q3/2012, an increase of 3% over Q3/2011 and 2% over Q2/2012;
- Generated funds from operations ("FFO") of $139.0 million ($1.15 per basic share) in Q3/2012, a decrease of 4% from Q3/2011, and an increase of 12% from Q2/2012;
- Generated net income of $26.8 million ($0.22 per basic share) in Q3/2012;
- Maintained a conservative cash payout ratio in Q3/2012 of 38% net of dividend reinvestment plan ("DRIP") participation (57% before DRIP);
- Issued $300 million of 6.625% Series C senior unsecured debentures due 2022 at par and redeemed $150 million of 9.15% Series A senior unsecured debentures due 2016; and
- Subsequent to the end of the third quarter, completed the acquisition of 46 sections of undeveloped oil sands leases in the Cold Lake area for a total purchase price of $120 million.

	Three Months Ended			Nine Months Ended	
	September 30, 2012	June 30, 2012	September 30, 2011	**September 30, 2012**	September 30, 2011
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**299,786**	284,248	313,787	**927,389**	941,001
Funds from operations[1]	**139,044**	124,692	144,825	**405,472**	392,510
Per share – basic	**1.15**	1.04	1.24	**3.39**	3.40
Per share – diluted	**1.14**	1.03	1.22	**3.34**	3.31
Cash dividends declared[2]	**52,640**	51,943	50,270	**160,142**	155,035
Cash dividends declared per share	**0.66**	0.66	0.60	**1.98**	1.80
Net income	**26,773**	157,280	51,839	**227,011**	159,652
Per share – basic	**0.22**	1.32	0.45	**1.90**	1.38
Per share – diluted	**0.22**	1.30	0.46	**1.87**	1.35
Exploration and development	**113,126**	102,895	100,368	**351,939**	295,835
Property acquisitions	**958**	10,173	28,502	**13,467**	65,835
Corporate acquisition	**–**	–	22	**–**	118,693
Proceeds from divestitures	**1,202**	(313,834)	–	**(316,200)**	–
Total oil and natural gas capital expenditures	**115,286**	(200,766)	128,892	**49,206**	480,363
Bank loan	**181,785**	396,207	368,184	**181,785**	368,184
Long-term debt	**447,555**	302,865	305,835	**447,555**	305,835
Working capital (surplus) deficiency	**(149,329)**	(261,153)	65,180	**(149,329)**	65,180
Total monetary debt[3]	**480,011**	437,919	739,199	**480,011**	739,199

	Three Months Ended			Nine Months Ended	
	September 30, 2012	June 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	7,047	7,090	7,170	7,233	6,612
Heavy oil (bbl/d)	40,580	38,579	37,280	39,176	34,324
Total oil and NGL (bbl/d)	47,627	45,669	44,450	46,409	40,936
Natural gas (mmcf/d)	40.5	44.4	49.0	43.3	49.3
Oil equivalent (boe/d @ 6:1)(4)	54,381	53,073	52,625	53,633	49,147
Average prices (before hedging)					
WTI oil (US$/bbl)	92.22	93.49	89.76	96.20	95.48
Edmonton par oil ($/bbl)	84.79	84.42	92.45	87.29	94.85
BTE light oil and NGL ($/bbl)	70.34	71.62	80.48	74.80	81.53
BTE heavy oil ($/bbl)(5)	60.11	57.42	59.92	61.12	63.54
BTE total oil and NGL ($/bbl)	61.63	59.63	63.26	63.25	66.45
BTE natural gas ($/mcf)	2.34	2.00	4.20	2.26	4.25
BTE oil equivalent ($/boe)	55.70	52.97	57.31	56.56	59.61
CAD/USD noon rate at period end	0.9837	1.0191	1.0389	0.9837	1.0389
CAD/USD average rate for period	0.9953	1.0102	0.9785	1.0023	0.9774
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	50.37	53.61	55.93	59.40	58.76
Low	39.91	38.54	41.71	38.54	41.71
Close	46.72	42.89	43.81	46.72	43.81
Volume traded (thousands)	25,679	34,162	27,710	83,219	84,765
NYSE					
Share price (US$)					
High	51.73	54.44	59.04	59.50	61.95
Low	39.50	37.40	40.31	37.40	40.31
Close	47.44	42.11	41.67	47.44	41.67
Volume traded (thousands)	5,823	8,257	11,771	18,568	29,806
Common shares outstanding (thousands)	120,962	119,914	116,755	120,962	116,755

Notes:

(1) Funds from operations is a non-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 months and nine months ended September 30, 2012.

(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 deferred income tax assets or liabilities and unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loans.

(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.

Forward-Looking Statements

This report contains forward-looking statements relating to: our average production rate for 2012; our exploration and development capital expenditures for 2012; our production mix for 2012; development plans for our properties, including the number of wells to be drilled in the remainder of 2012; initial production rates from wells drilled; our Cliffdale cyclic steam stimulation project, including our assessment of the steam and flowback operations, the cumulative steam-oil ratio for the project and our plan for a second commercial module of cyclic steam stimulation; our Lloydminster heavy oil area, including the development potential of these properties, our ability to exploit multiple horizons and estimated 30-day peak productions rates from new horizontal and vertical wells; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate; the demand for Canadian heavy oil by U.S. refiners; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate our exposure to heavy oil price differentials by transporting our crude oil to market by railways; the volume of heavy oil to be transported to market by railways in 2012; the application of the proceeds from the sale of our non-operated interests in North Dakota; the amount of our undrawn credit facilities at September 30, 2012; our debt-to-FFO ratio; our pro forma financial position following the acquisition of undeveloped oil sands leases at Cold Lake and the repatriation of the proceeds from the sale of our non-operated interests in North Dakota; 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 FFO 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 statements.

Non-GAAP Financial Measures

In this report we refer to certain measures that are commonly used in the oil and gas industry but are not based on generally accepted accounting principles in Canada, such as funds from operations and total monetary debt. For a description of these measures, we refer you to "Non-GAAP Financial Measures" in the Management's Discussion and Analysis section of this report.

All amounts in this report are stated in Canadian dollars unless otherwise noted.

Operations Review

Production averaged 54,381 boe/d (88% oil and NGL) during the third quarter of 2012, as compared to 52,625 boe/d (84% oil and NGL) in the third quarter of 2011 and 53,073 boe/d (86% oil and NGL) in the second quarter of 2012. The third quarter of 2012 was the first full quarter which reflected the Q2/2012 sale of approximately 950 boe/d of light oil produced in North Dakota. Compared to the third quarter of 2011, oil and NGL production increased 7%, while natural gas production decreased 17%. Compared to the second quarter of 2012, oil and NGL production increased 4%, while natural gas production decreased 9%. During 2012, we have focused our capital investment on more profitable crude oil investment opportunities resulting in minimal drilling activity for natural gas.

Our 2012 production guidance remains at 53,500 to 54,500 boe/d with 2012 exploration and development capital expenditures forecast to be approximately $400 million. Our production mix for 2012 is forecast to be 73% heavy oil, 14% light oil and NGL and 13% natural gas. We plan to provide production and capital budget guidance for 2013 in early December, following approval of our 2013 development plan by our Board of Directors.

Capital expenditures for exploration and development activities totaled $113 million for the third quarter of 2012. During the third quarter, Baytex participated in the drilling of 55 (47.9 net) wells with a 98% success rate. Through the first nine months of 2012, Baytex has participated in the drilling of 181 (142.2 net) wells with a 98% success rate.

Wells Drilled – Three months ended September 30, 2012

	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	29	28.7	–	–	–	–	–	–	1	1.0	30	29.7
Peace River area	9	9.0	–	–	–	–	–	–	–	–	9	9.0
	38	**37.7**	**–**	**–**	**–**	**–**	**–**	**–**	**1**	**1.0**	**39**	**38.7**
Light oil, NGL and natural gas												
Western Canada	7	5.5	–	–	1	1.0	–	–	–	–	8	6.5
North Dakota	8	2.7	–	–	–	–	–	–	–	–	8	2.7
	15	8.2	–	–	1	1.0	–	–	–	–	16	9.2
Total	**53**	**45.9**	**–**	**–**	**1**	**1.0**	**–**	**–**	**1**	**1.0**	**55**	**47.9**

Wells Drilled – Nine months ended September 30, 2012

	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	77	67.1	–	–	–	–	1	1.0	2	2.0	80	70.1
Peace River area	27	27.0	5	5.0	–	–	13	13.0	–	–	45	45.0
	104	**94.1**	**5**	**5.0**	**–**	**–**	**14**	**14.0**	**2**	**2.0**	**125**	**115.1**
Light oil, NGL and natural gas												
Western Canada	18	14.3	–	–	3	3.0	–	–	1	1.0	22	18.3
North Dakota	34	8.8	–	–	–	–	–	–	–	–	34	8.8
	52	23.1	–	–	3	3.0	–	–	1	1.0	56	27.1
Total	**156**	**117.2**	**5**	**5.0**	**3**	**3.0**	**14**	**14.0**	**3**	**3.0**	**181**	**142.2**

Heavy Oil

In the third quarter of 2012, heavy oil production averaged 40,580 bbl/d, an increase of 9% over the third quarter of 2011 and 5% over the second quarter of 2012. During the third quarter of 2012, we drilled 39 (38.7 net) wells on our heavy oil properties with a success rate of 97%.

Production from our Peace River area properties averaged approximately 21,350 bbl/d in the third quarter, an increase of 20% over the third quarter of 2011 and 11% over the second quarter of 2012. In the third quarter of 2012, we drilled nine (9.0 net) horizontal oil wells in the Seal area (encompassing a total of 116 laterals). During the third quarter, ten wells established average 30-day peak production rates of approximately 410 bbl/d. We plan to drill approximately six horizontal wells in the Peace River area in the remainder of the year.

In the Cliffdale area, successful operations continued at our 10-well commercial cyclic steam stimulation ("CSS") module, with production during the third quarter averaging approximately 420 bbl/d, consistent with project design parameters. During the third quarter, five wells received steam and three wells commenced post-steam flowback operations. Of those three wells, two wells delivered first-cycle peak oil rates of 262 bbl/d and 330 bbl/d, respectively, and one well delivered a second-cycle peak oil rate of 310 bbl/d. First and second-cycle steam injection volumes were encouraging and have exceeded the first-cycle injection performance demonstrated by the pilot well. Fourth-cycle flowback operations on the pilot well continued in the third quarter. Subsequent to the end of third quarter, the final two wells commenced their initial steam injection phase. To date, the Cliffdale project has demonstrated a cumulative steam-oil-ratio of approximately 2.0 barrels of steam per barrel of oil. Subject to receipt of regulatory approvals, we plan to initiate development of a new 15-well commercial CSS module in the first quarter of 2013.

In our Lloydminster heavy oil area, third quarter drilling included nine (9.0 net) horizontal oil wells and 20 (19.7 net) vertical oil wells. This area is characterized by stacked pay which has led to successful exploitation of multiple horizons. Our Lloydminster heavy oil projects generate consistent, repeatable results with horizontal wells typically producing 30-day peak rates of approximately 70-80 bbl/d and vertical wells typically producing 30-day peak rates of approximately 30-40 bbl/d. We expect to drill approximately seven horizontal wells and one vertical well in the Lloydminster area in the remainder of the year.

Subsequent to the end of the third quarter, we acquired a 100% working interest in 46 sections of undeveloped oil sands leases in the Cold Lake area of Northern Alberta for total consideration of $120 million. The lands are proximal to our existing Cold Lake heavy oil assets and are prospective for both cold and thermal development. In addition, we increased our land position in the Peace River area, adding 28.75 sections of prospective oil sands leases.

Light Oil & Natural Gas

During the third quarter of 2012, light oil, NGL and natural gas production averaged 13,801 boe/d, which was comprised of 7,047 bbl/d of light oil and NGL and 40.5 mmcf/d of natural gas. Compared to the third quarter of 2011, light oil and NGL production decreased 2% and natural gas production decreased 17%. Compared to the second quarter of 2012, light oil and NGL production decreased 1% and natural gas production decreased 9%. Third quarter light oil production was impacted by the previously announced North Dakota non-operated asset sale which closed in May and included approximately 950 boe/d.

During the third quarter of 2012, we drilled four (3.5 net) horizontal wells in our Viking light oil resource play in Central Alberta. One Viking well drilled in the second quarter and three Viking wells drilled in the third quarter established average 30-day peak rates of 90 bbl/d during the third quarter.

In our Bakken/Three Forks play in North Dakota, we participated in the drilling of eight (2.7 net) horizontal oil wells, seven of which were Baytex-operated, and the fracture-stimulation of 10 (3.2 net) wells in the third quarter. During the third quarter, seven Baytex-operated wells (1,280-acre spacing) established average 30-day peak rates of approximately 445 boe/d. We plan to drill approximately five (1.5 net) wells on our Bakken/Three Forks play in North Dakota during the remainder of 2012.

Financial Review

We generated FFO of $139 million ($1.15 per basic share) in Q3/2012, a decrease of 4% compared to Q3/2011, and an increase of 12% compared to Q2/2012. The increase relative to Q2/2012 was the result of increased sales volumes and higher realized oil prices.

The average WTI price for Q3/2012 was US$92.22, a 3% increase from Q3/2011 and a 1% decrease from Q2/2012. We received an average oil and NGL price of $61.63/bbl in Q3/2012 (inclusive of our physical hedging gains), down 3% from $63.26/bbl for Q3/2011 and up 3% from $59.63/bbl for Q2/2012. We received an average natural gas price of $2.34/mcf in Q3/2012, down 44% from $4.20/mcf for Q3/2011 and up 17% from $2.00/mcf for Q2/2012.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged almost 24% in Q3/2012, the same as for the preceding quarter. As the third quarter progressed, the monthly WCS differentials improved due to higher U.S. refinery runs as well as increasing rail shipments of Canadian heavy oil. During the nine months ended September 30, 2012, the WCS price differential was 23%, as compared to 20% for the first nine months of 2011.

Baytex continues to actively hedge its exposure to commodity prices and foreign exchange rates. We have established forward contracts for the fourth quarter of 2012 on approximately 46% of our WTI price exposure, 40% of our heavy oil differential exposure, 46% of our natural gas price exposure, and 31% of our exposure to currency movements between the Canadian and U.S. dollars. We have begun to secure hedging contracts on our 2013 exposures and have established forward contracts for the first and second half of 2013 on approximately 24% and 16%, respectively, of our WTI exposure and 38% and 25%, respectively, of our heavy oil differential exposure. Details of all hedging contracts are contained in the notes to our interim financial statements. We continue to monitor the markets for opportunities to add to our hedge positions. As part of our hedging program, we continue to mitigate exposure to WCS price differentials by transporting crude oil to higher value markets by railways. By the end of this year we expect to deliver approximately 30% of our heavy oil volumes by rail, and we continue to explore opportunities for additional rail deliveries for 2013 and beyond.

During Q2/2012, Baytex completed the previously disclosed sale of non-operated interests in North Dakota for net proceeds of $314 million (US$312 million). In order to potentially defer the payment of income tax on the gain realized on the sale, we deposited the sale proceeds into escrow pending the acquisition of qualifying replacement properties. In July 2012, US$112 million of the sale proceeds were returned from escrow and used to reduce borrowings on our credit facilities. As we do not expect to acquire qualifying replacement properties within the prescribed time frame, the balance of the escrowed funds of US$200 million will be returned to us in late November 2012 (at which time they will be used to reduce borrowings on our credit facilities).

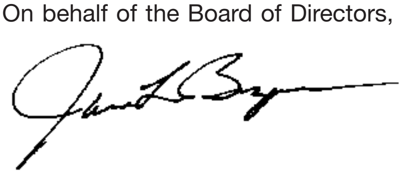
We ended the quarter with total monetary debt of $480 million representing a debt-to-FFO ratio of 0.84 times, based on FFO over the trailing twelve-month period. In July 2012, we issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par. A portion of the net proceeds of this issue was used to redeem $150 million of 9.15% Series A senior unsecured debentures on August 26, 2012 at 104.575% of principal amount, with the remaining proceeds used to reduce borrowings on our credit facilities. Pro forma the Cold Lake acquisition and the repatriation of the remaining North Dakota sale proceeds, our total bank borrowings would be approximately $104 million, leaving us with $596 million of undrawn credit facilities.

Conclusion

Baytex's operations continue to advance in accordance with our business plan. During the third quarter, our capital execution was on target, and we remain on track to meet our full-year production guidance. We continue to add high-quality acreage to our portfolio, both within our Peace River Oil Sands and our Lloydminster regions. Our balance sheet remains in excellent shape with significant undrawn credit facilities. Utilizing our significant resource base, we will continue to execute our growth and income business 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
November 13, 2012

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 months and nine months ended September 30, 2012. This information is provided as of November 12, 2012. 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 2011. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three months and nine months ended September 30, 2012 and 2011, its audited consolidated comparative financial statements for the years ended December 31, 2011 and 2010, together with accompanying notes, and its Revised Annual Information Form for the year ended December 31, 2011. 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 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 for 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 deferred income tax assets or liabilities and 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. 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		
	2012	2011	Change	**2012**	2011	Change
Daily Production						
Light oil and NGL (bbl/d)	**7,047**	7,170	(2%)	**7,233**	6,612	9%
Heavy oil (bbl/d)[1]	**40,580**	37,280	9%	**39,176**	34,324	14%
Natural gas (mmcf/d)	**40.5**	49.0	(17%)	**43.3**	49.3	(12%)
Total production (boe/d)	**54,381**	52,625	3%	**53,633**	49,147	9%
Production Mix						
Light oil and NGL	**13%**	14%	–	**14%**	13%	–
Heavy oil	**75%**	71%	–	**73%**	70%	–
Natural gas	**12%**	15%	–	**13%**	17%	–

(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, 2012, heavy oil sales volumes were 149 bbl/d lower than production volumes (three months ended September 30, 2011 – 369 bbl/d lower). For the nine months ended September 30, 2012, heavy oil sales volumes were 49 bbl/d lower than production volumes (nine months ended September 30, 2011 – 89 bbl/d higher).*

Production for the three months ended September 30, 2012 averaged 54,381 boe/d, compared to 52,625 boe/d for the same period in 2011. Light oil and natural gas liquids ("NGL") production decreased by 2% to 7,047 bbl/d in the third quarter of 2012 from 7,170 bbl/d in the third quarter of 2011 primarily due to the production impact of our U.S. asset sale in the second quarter of 2012. Heavy oil production for the third quarter of 2012 increased by 9% to 40,580 bbl/d from 37,280 bbl/d a year ago primarily due to development activities. Natural gas production decreased by 17% to 40.5 mmcf/d for the third quarter of 2012, as compared to 49.0 mmcf/d for the same period in 2011 primarily due to natural declines as we focused our capital spending on our oil projects.

Production for the nine months ended September 30, 2012 averaged 53,633 boe/d, compared to 49,147 boe/d for the same period in 2011. Light oil and NGL production increased by 9% to 7,233 bbl/d from 6,612 bbl/d due to development activities in the U.S. and Canada, and production interruptions in 2011 from wet weather in North Dakota, as well as forest fires, and pipeline curtailments in Alberta. Light oil and NGL production increases were reduced by the U.S. asset sale in the second quarter of 2012. Heavy oil production for the nine months ended September 30, 2012 increased by 14% to 39,176 bbl/d from 34,324 bbl/d a year ago primarily due to development activities. Natural gas production decreased by 12% to 43.3 mmcf/d for the first nine months of 2012, as compared to 49.3 mmcf/d for the same period in 2011 primarily due to natural declines as we focused our capital spending on our oil projects.

Commodity Prices

Crude Oil

For the first nine months of 2012, the prompt price of WTI fluctuated between a low of US$77.69/bbl and a high of US$109.77/bbl, with an average price of US$96.20/bbl. Prevalent drivers to oil price during this period were: a bullish macroeconomic environment, escalating tension over Iran's nuclear program early in the period followed by renewed concerns of a global slowdown (particularly Europe and China), and weaker oil fundamentals as Saudi Arabia increased sustained production to over 10 million barrels per day, which contributed to oil prices being under US$80.00/bbl for a short period. From mid-summer, oil prices rallied on a combination of expected U.S. federal reserve monetary easing, together with increasing geopolitical tensions over both Iran and Syria. For the three months ending September 30, 2012, the prompt WTI oil price averaged US$92.22/bbl, while ranging from a low of US$83.75/bbl at the start of the quarter and a high of US$99.00/bbl shortly after the U.S. federal reserve's announcement of a third round of quantitative easing.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 23% in the nine months ended September 30, 2012, as compared to 20% for the first nine months of 2011. During the third quarter of 2012 and 2011, the WCS heavy oil differential averaged 24% and 20%, respectively. As the third quarter progressed, the monthly WCS differential improved due to higher U.S. refining runs as well as increasing rail shipments of Canadian heavy oil.

Natural Gas

For the nine months ended September 30, 2012, the average AECO natural gas price was $2.18/mcf, as compared to $3.75/mcf in the same period of 2011. The decrease in the natural gas price was due to higher U.S. natural gas production and a relatively mild 2012 winter season in major natural gas consumption areas, which brought U.S. and western Canada natural gas storage levels to record highs. For the three months ended September 30, 2012, AECO natural gas price was $2.19/mcf, as compared to $3.72/mcf in the same period of 2011, and $1.84/mcf in the second quarter of 2012. The increase in the natural gas price versus the second quarter of 2012 was the result of a combination of warm weather in U.S. markets, increased use of gas by U.S. power producers and a decline in U.S. drilling for natural gas.

	Three Months Ended September 30			Nine Months Ended September 30		
	2012	2011	Change	**2012**	2011	Change
Benchmark Averages						
WTI oil (US$/bbl)(1)	**$ 92.22**	$ 89.76	3%	**$ 96.20**	$ 95.48	1%
WCS heavy oil (US$/bbl)(2)	**$ 70.50**	$ 72.14	(2%)	**$ 74.20**	$ 76.10	(2%)
Heavy oil differential(3)	**24%**	20%		**23%**	20%	
CAD/USD average exchange rate	**0.9953**	0.9785	2%	**1.0023**	0.9774	3%
Edmonton par oil ($/bbl)	**$ 84.79**	$ 92.45	(8%)	**$ 87.29**	$ 94.85	(8%)
AECO natural gas price ($/mcf)(4)	**$ 2.19**	$ 3.72	(41%)	**$ 2.18**	$ 3.75	(42%)
Baytex Average Sales Prices						
Light oil and NGL ($/bbl)	**$ 70.34**	$ 80.48	(13%)	**$ 74.80**	$ 81.53	(8%)
Heavy oil ($/bbl)(5)	**$ 59.45**	$ 59.12	1%	**$ 60.06**	$ 62.53	(4%)
Physical forward sales contracts gain (loss) ($/bbl)	**0.66**	0.80		**1.06**	1.01	
Heavy oil, net ($/bbl)	**$ 60.11**	$ 59.92	–	**$ 61.12**	$ 63.54	(4%)
Total oil and NGL, net ($/bbl)	**$ 61.63**	$ 63.26	(3%)	**$ 63.25**	$ 66.45	(5%)
Natural gas ($/mcf)(6)	**$ 2.34**	$ 3.89	(40%)	**$ 2.26**	$ 3.95	(43%)
Physical forward sales contracts gain ($/mcf)	**–**	0.31		**–**	0.30	
Natural gas, net ($/mcf)	**$ 2.34**	$ 4.20	(44%)	**$ 2.26**	$ 4.25	(47%)
Summary						
Weighted average ($/boe)(6)	**$ 55.13**	$ 56.32	(2%)	**$ 55.66**	$ 58.45	(5%)
Physical forward sales contracts gain (loss) ($/boe)	**0.57**	0.99		**0.90**	1.16	
Weighted average, net ($/boe)	**$ 55.70**	$ 57.31	(3%)	**$ 56.56**	$ 59.61	(5%)

(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 monthly 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.

During the third quarter of 2012, Baytex's average sales price for light oil and NGL was $70.34/bbl, down 13% from $80.48/bbl in the third quarter of 2011. Baytex's realized heavy oil price during the third quarter of 2012, prior to physical forward sales contracts, was $59.45/bbl, or 85% of WCS. This compares to a realized heavy oil price in the third quarter of 2011, prior to physical forward sales contracts, of $59.12/bbl, or 84% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the third quarter of 2012 was $60.11/bbl, slightly up from $59.92/bbl in the third quarter of 2011. Baytex's realized natural gas price for the three months ended September 30, 2012 was $2.34/mcf with no applicable physical forward sales contracts (three months ended September 30, 2011 – $3.89/mcf prior to physical forward sales contracts and $4.20/mcf inclusive of physical forward sales contracts).

In the first nine months of 2012, Baytex's average sales price for light oil and NGL was $74.80/bbl, down 8% from $81.53/bbl in the first nine months of 2011. Baytex's realized heavy oil price during the first nine months of 2012, prior to physical forward sales contracts, was $60.06/bbl or 85% of WCS. This compares to a realized heavy oil price in the first nine months of 2011, prior to physical forward sales contracts, of $62.53/bbl, or 84% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the first nine months of 2012 was $61.12/bbl, down 4% from $63.54/bbl in the first nine months of 2011. Baytex's realized natural gas price for the nine months ended September 30, 2012 was $2.26/mcf with no applicable physical forward sales contracts (nine months ended September 30, 2011 – $3.95/mcf prior to physical forward sales contracts and $4.25/mcf inclusive of physical forward sales contracts).

Gross Revenues

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for %)	**2012**	2011	Change	**2012**	2011	Change
Oil revenue						
Light oil and NGL	**$ 45,594**	$ 53,808	(15%)	**$ 148,244**	$ 147,899	–
Heavy oil	**223,599**	203,486	10%	**655,235**	595,838	10%
Total oil revenue	**269,193**	257,294	5%	**803,479**	743,737	8%
Natural gas revenue	**8,708**	18,962	(54%)	**26,869**	57,155	(53%)
Total oil and natural gas revenue	**277,901**	276,256	1%	**830,348**	800,892	4%
Heavy oil blending diluent revenue	**21,885**	37,531	(42%)	**97,041**	140,109	(31%)
Total petroleum and natural gas revenues	**$ 299,786**	$ 313,787	(4%)	**$ 927,389**	$ 941,001	(1%)

Petroleum and natural gas revenues decreased 4% to $299.8 million for the three months ended September 30, 2012 from $313.8 million for the same period in 2011. Lower light oil and natural gas prices were offset by higher sales volumes and slightly higher heavy oil prices as compared to the three months ended September 30, 2011. Heavy oil blending diluent revenues were down 42% for the three months ended September 30, 2012 from the same period last year because of the increased volumes transported by railways. Unlike transportation through oil pipelines, transportation of bitumen by rail does not require condensate blending.

For the nine months ended September 30, 2012, petroleum and natural gas revenues totaled $927.4 million, down 1% from $941.0 million for the same period in 2011. Lower realized petroleum and natural gas prices during the nine months ended September 30, 2012 were offset by higher sales volumes as compared to the nine months ended September 30, 2011. Heavy oil blending diluent revenues were down 31% for the nine months ended September 30, 2012 from the same period last year because of the increased volumes transported by railways. Unlike transportation through oil pipelines, transportation of bitumen by rail does not require condensate blending.

Royalties

($ thousands except for % and per boe)	Three Months Ended September 30 2012	2011	Change	Nine Months Ended September 30 2012	2011	Change
Royalties	$ 47,758	$ 50,656	(6%)	$ 146,772	$ 150,617	(3%)
Royalty rates:						
Light oil, NGL and natural gas	18.6%	20.8%		18.5%	18.9%	
Heavy oil	16.9%	17.6%		17.5%	18.8%	
Average royalty rates(1)	17.2%	18.4%		17.7%	18.8%	
Royalty expenses per boe	$ 9.57	$ 10.54	(9%)	$ 10.00	$ 11.22	(11%)

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

Total royalties for the third quarter of 2012 decreased to $47.8 million from $50.7 million in the third quarter of 2011. Total royalties for the third quarter of 2012 were 17.2% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 18.4% for the same period in 2011. Total royalties for the nine months ended September 30, 2012 decreased to $146.8 million from $150.6 million in the nine months ended September 30, 2011. Total royalties for the first nine months of 2012 were 17.7% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 18.8% for the same period in 2011.

Royalty rates for light oil, NGL and natural gas for the third quarter decreased from 20.8% in the three months ended September 30, 2011 to 18.6% in the three months ended September 30, 2012. Royalty rates for heavy oil in the third quarter decreased from 17.6% in the three months ended September 30, 2011 to 16.9% in 2012. The overall royalty rate decrease resulted from a higher number of wells qualifying under the lower royalty incentive rate for new wells in Alberta. In addition, our steam-assisted gravity drainage project at Kerrobert, Saskatchewan also had a favourable royalty adjustment resulting from an audit of prior year qualifying expenditures.

Royalty rates for light oil, NGL and natural gas for the nine months ended September 30 decreased from 18.9% in 2011 to 18.5% in 2012. Royalty rates for heavy oil for the nine months ended September 30 decreased from 18.8% in 2011 to 17.5% in 2012. The year-to-date royalty decreases were primarily due to the same factors as discussed above for the third quarter.

Financial Derivatives

($ thousands)	Three Months Ended September 30 2012	2011	Change	Nine Months Ended September 30 2012	2011	Change
Realized gain (loss) on financial derivatives[1]						
Crude oil	$ 6,945	$ 3,114	$ 3,831	$ 6,080	$ (14,355)	$ 20,435
Natural gas	1,642	102	1,540	4,630	59	4,571
Foreign currency	1,676	2,907	(1,231)	4,474	13,701	(9,227)
Interest rate	(1,690)	104	(1,794)	(3,271)	32	(3,303)
Total	$ 8,573	$ 6,227	$ 2,346	$ 11,913	$ (563)	$ 12,476
Unrealized gain (loss) on financial derivatives[2]						
Crude oil	$ (12,405)	$ 58,710	$ (71,115)	$ 31,986	$ 62,303	$ (30,317)
Natural gas	(1,861)	2,287	(4,148)	(3,469)	3,792	(7,261)
Foreign currency	5,813	(23,372)	29,185	6,232	(26,069)	32,301
Interest rate	1,314	(6,609)	7,923	1,294	(5,878)	7,172
Total	$ (7,139)	$ 31,016	$ (38,155)	$ 36,043	$ 34,148	$ 1,895
Total gain (loss) on financial derivatives						
Crude oil	$ (5,460)	$ 61,824	$ (67,284)	$ 38,066	$ 47,948	$ (9,882)
Natural gas	(219)	2,389	(2,608)	1,161	3,851	(2,690)
Foreign currency	7,489	(20,465)	27,954	10,706	(12,368)	23,074
Interest rate	(376)	(6,505)	6,129	(1,977)	(5,846)	3,869
Total	$ 1,434	$ 37,243	$ (35,809)	$ 47,956	$ 33,585	$ 14,371

(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 gain of $8.6 million for the three months ended September 30, 2012 on derivative contracts relates to favorable contracts entered into in early 2012 when crude oil prices were high, a strengthening Canadian dollar against the U.S. dollar and lower natural gas prices. The unrealized mark-to-market loss of $7.1 million for the three months ended September 30, 2012 relates to higher commodity prices at September 30, 2012, as compared to June 30, 2012, partially offset by a strengthening Canadian dollar against the U.S. dollar.

The realized gain of $11.9 million for the nine months ended September 30, 2012 relates to lower commodity prices and favorable foreign currency contracts, partially offset by losses on interest rate contracts. The unrealized mark-to-market gain of $36.0 million for the nine months ended September 30, 2012 relates to lower crude oil prices and a strengthening Canadian dollar against the U.S. dollar at September 30, 2012, as compared to December 31, 2011.

A summary of the risk management contracts in place as at September 30, 2012 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 2012	2011	Change	Nine Months Ended September 30 2012	2011	Change
Production and operating expenses	$ 57,093	$ 55,936	2%	$ 172,347	$ 153,601	12%
Production and operating expenses per boe:						
Heavy oil	$ 10.68	$ 11.08	(4%)	$ 10.78	$ 11.14	(3%)
Light oil, NGL and natural gas	$ 13.67	$ 12.98	5%	$ 14.32	$ 12.14	18%
Total	$ 11.44	$ 11.64	(2%)	$ 11.74	$ 11.44	3%

Production and operating expenses for the three months ended September 30, 2012 increased to $57.1 million from $55.9 million due to increased production volumes attributable to the development of existing assets in Canada and the U.S. The increased production volume also resulted in lower production and operating expenses of $11.44/boe for the three months ended September 30, 2012, as compared to $11.64/boe for the same period in 2011. The decrease of 4% per boe for heavy oil was partially offset by the 5% increase per boe for light oil, NGL and natural gas, resulting in a 2% net decrease per boe of production and operating expenses.

Production and operating expenses for the nine months ended September 30, 2012 increased to $172.3 million from $153.6 million due to increased production volumes attributable to the development of existing assets in Canada and the U.S. and from the Reno and Brewster acquisitions completed in February and August 2011, respectively. Production and operating expenses were $11.74/boe for the nine months ended September 30, 2012, as compared to $11.44/boe for the same period in 2011. Total production and operating expenses increased by 3% primarily due to higher production and increased labour costs.

Transportation and Blending Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for % and per boe)	2012	2011	Change	2012	2011	Change
Blending expenses	$ 21,885	$ 37,531	(42%)	$ 97,041	$ 140,109	(31%)
Transportation expenses	22,541	16,528	36%	56,912	45,628	25%
Total transportation and blending expenses	$ 44,426	$ 54,059	(18%)	$ 153,953	$ 185,737	(17%)
Transportation expenses per boe(1):						
Heavy oil	$ 5.88	$ 4.51	30%	$ 5.08	$ 4.52	12%
Light oil, NGL and natural gas	$ 0.52	$ 0.85	(39%)	$ 0.61	$ 0.81	(25%)
Total	$ 4.52	$ 3.44	31%	$ 3.88	$ 3.40	14%

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

Transportation and blending expenses for the third quarter of 2012 were $44.4 million, as compared to $54.1 million for the third quarter of 2011. Transportation and blending expenses for the first nine months of 2012 were $154.0 million, as compared to $185.7 million for the first nine months of 2011.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. In most cases, Baytex purchases condensate from industry producers as the blending diluent facilitates the marketing of its heavy oil. In the third quarter of 2012, blending expenses were $21.9 million for the purchase of 3,080 bbl/d of condensate at $77.23/bbl, as compared to $37.5 million for the purchase of 4,287 bbl/d at $95.16/bbl for the same period last year. In the nine months ended September 30, 2012, blending expenses were $97.0 million for the purchase of 3,407 bbl/d of condensate at $103.94/bbl, as compared to $140.1 million for the purchase of 5,116 bbl/d at $100.32/bbl for the same period last year. This decrease in blending for both the three and nine month periods ending September 30, 2012 is due to rail transportation of heavy oil, which does not require diluent blending, as compared to no rail deliveries in the prior periods. The cost of blending diluent is effectively recovered in the sale price of a blended product.

Transportation expenses were $4.52/boe for the three months ended September 30, 2012, as compared to $3.44/boe for the same period of 2011. Transportation expenses were $3.88/boe for the nine months ended September 30, 2012, as compared to $3.40/boe for the same period of 2011. The increase in transportation expenses per barrel of heavy oil for the three and nine months ended September 30, 2012 is primarily driven by a larger portion of our heavy oil production coming from our Seal and Reno areas which utilize long-haul trucking to ship a portion of production volumes.

Operating Netback

($ per boe except for % and volume)	Three Months Ended September 30 2012	2011	Change	Nine Months Ended September 30 2012	2011	Change
Sales volume (boe/d)	54,233	52,256	4%	53,584	49,171	9%
Operating netback[1]:						
Sales price[2]	$ 55.70	$ 57.31	(3%)	$ 56.56	$ 59.61	(5%)
Less:						
Royalties	9.57	10.54	(9%)	10.00	11.22	(11%)
Operating expenses	11.44	11.64	(2%)	11.74	11.44	3%
Transportation expenses	4.52	3.44	31%	3.88	3.40	14%
Operating netback before financial derivatives	$ 30.17	$ 31.69	(5%)	$ 30.94	$ 33.55	(8%)
Financial derivatives gain (loss)[3]	1.72	1.30	32%	0.81	(0.04)	2,125%
Operating netback after financial derivatives gain (loss)	$ 31.89	$ 32.99	(3%)	$ 31.75	$ 33.51	(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) only.

Evaluation and Exploration Expense

Evaluation and exploration expense for the three months ended September 30, 2012 decreased to $2.6 million from $3.3 million for the same period in 2011 due to a decrease in the expiration of undeveloped land leases. Evaluation and exploration expense for the nine months ended September 30, 2012 decreased to $9.5 million from $10.1 million for the same period in 2011.

Depletion and Depreciation

Depletion and depreciation for the three months ended September 30, 2012 increased to $71.6 million from $63.4 million for the same period in 2011. On a sales-unit basis, the provision for the current quarter was $14.36/boe, as compared to $12.56/boe for the same quarter in 2011. The increase relates primarily to an increase in estimates of future development costs resulting in a higher depletable base.

Depletion and depreciation for the nine months ended September 30, 2012 increased to $214.5 million from $176.5 million for the same period in 2011. On a sales-unit basis, the provision for the first nine months of 2012 was $14.61/boe, as compared to $13.15/boe for the same period in 2011. The increase relates primarily to an increase in estimates of future development costs resulting in a higher depletable base.

General and Administrative Expenses

($ thousands except for % and per boe)	Three Months Ended September 30 2012	2011	Change	Nine Months Ended September 30 2012	2011	Change
General and administrative expenses	$ 9,914	$ 9,604	3%	$ 32,239	$ 29,423	10%
General and administrative expenses per boe	$ 1.99	$ 2.00	(1%)	$ 2.20	$ 2.19	–

General and administrative expenses for the third quarter of 2012 increased to $9.9 million from $9.6 million for the same period in 2011 due to higher salary costs and higher office rent. On a per boe basis, general and administrative expenses decreased slightly from $2.00 in the third quarter of 2011 to $1.99 in the third quarter of 2012.

General and administrative expenses for the nine months ended September 30, 2012 increased to $32.2 million from $29.4 million for the same period in 2011 due to higher salary costs and higher office rent. On a per boe basis, general and administrative expenses increased slightly from $2.19 in the first nine months of 2011 to $2.20 in the first nine months of 2012.

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 Rights Plan decreased to $1.0 million in the third quarter of 2012 (three months ended September 30, 2011 – $3.9 million) while compensation expense related to the Share Award Incentive Plan increased to $8.8 million for the three months ended September 30, 2012 (three months ended September 30, 2011 – $5.9 million). Overall compensation expense remained constant quarter over quarter.

Compensation expense related to the Share Rights Plan decreased to $2.2 million in the nine months ended September 30, 2012 (nine months ended September 30, 2011 – $13.7 million) while compensation expense related to the Share Award Incentive Plan increased to $26.8 million for the nine months ended September 30, 2012 (nine months ended September 30, 2011 – $11.5 million). The overall increase in compensation expense of $3.8 million is mainly due to the conversion of restricted awards and performance awards held by a departed executive during the second quarter of 2012.

Compensation expense associated with the Share Rights Plan and the Share Award Incentive Plan is recognized in income over the vesting period of the share rights or share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the exercise of share rights or conversion of share awards 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 %)	2012	2011	Change	2012	2011	Change
Bank loan and other	$ 2,488	$ 2,583	(4%)	$ 8,172	$ 9,389	(13%)
Long-term debt	8,700	6,088	43%	20,981	16,793	25%
Accretion on asset retirement obligations	1,663	1,558	7%	4,942	4,558	8%
Debt financing costs	11	154	(93%)	860	2,998	(71%)
Financing costs	$ 12,862	$ 10,383	24%	$ 34,955	$ 33,738	4%

Financing costs for the three months ended September 30, 2012 increased to $12.9 million, as compared to $10.4 million in the third quarter of 2011. The increase was primarily attributable to interest on the $300 million principal amount of 6.625% Series C senior unsecured debentures issued on July 19, 2012, offset by lower interest on the $150 million principal amount of 9.15% Series A senior unsecured debentures issued that were redeemed on August 26, 2012 and lower interest on bank loan due to lower bank borrowings outstanding.

Financing costs for the nine months ended September 30, 2012 increased to $35.0 million, as compared to $33.7 million in the first nine months of 2011. The increase was primarily attributable to interest on the $300 million principal amount of 6.625% Series C senior unsecured debentures issued on July 19, 2012, and higher interest in 2012 from the US$150 million principal amount of 6.75% Series B senior unsecured debentures issued on February 17, 2011. These increases were partially offset by lower interest on the $150 million principal amount of 9.15% Series A senior unsecured debentures issued that were redeemed on August 26, 2012, lower credit facility amendment fees and lower interest on bank loan due to lower bank borrowings outstanding.

Foreign Exchange

($ thousands except for % and exchange rates)	Three Months Ended September 30 2012	2011	Change	Nine Months Ended September 30 2012	2011	Change
Unrealized foreign exchange (gain) loss	$ (5,346)	$ 24,257	(122%)	$ (3,234)	$ 14,655	(122%)
Realized foreign exchange gain	(902)	(4,418)	(80%)	(1,002)	(2,752)	(64%)
Total (gain) loss	$ (6,248)	$ 19,839	(131%)	$ (4,236)	$ 11,903	(136%)
CAD/USD exchange rates:						
At beginning of period	1.0191	0.9643		1.0170	0.9946	
At end of period	0.9837	1.0389		0.9837	1.0389	

The third quarter of 2012 unrealized gain of $5.3 million, as compared to a loss of $24.3 million for the third quarter of 2011, was mainly due to the translation of the US$150 million Series B senior unsecured debentures as the Canadian dollar strengthened against the U.S. dollar at September 30, 2012 (as compared to June 30, 2012) and weakened at September 30, 2011 (as compared to June 30, 2011). The current quarter realized gains were mainly due to the settlement of the US$180 million portion of the bank loan at a stronger CAD/USD exchange rate on settlement date as compared to December 31, 2011, partially offset by losses on day-to-day U.S. dollar denominated transactions.

The unrealized gain in the first nine months of 2012 of $3.2 million, as compared to a loss of $14.7 million for the first nine months of 2011, was mainly due to the translation of the US$150 million Series B senior unsecured debentures as the Canadian dollar strengthened against the U.S. dollar at September 30, 2012 (as compared to December 31, 2011) and weakened at September 30, 2011 (as compared to December 31, 2010). The year to date realized gains were due to the settlement of the US$180 million portion of the bank loan at a stronger CAD/USD exchange rate on settlement date as compared to December 31, 2011, partially offset by losses on day-to-day U.S. dollar denominated transactions.

Income Taxes

For the nine months ended September 30, 2012, total income tax expense was $122.8 million (nine months ended September 30, 2011 – $39.7 million) of which $13.6 million related to current income taxes (nine months ended September 30, 2011 – $nil) and $109.2 million related to deferred income taxes (nine months ended September 30, 2011 – $39.7 million). Current income tax expense relates primarily to the disposition of non-operated assets in North Dakota during the second quarter of 2012. The gain on disposition is, to the extent possible, sheltered from current taxes by available U.S. tax deductions. The unsheltered portion of the gain results in a $13.6 million current tax expense payable to U.S. federal and state tax authorities.

Net Income

Net income for the three months ended September 30, 2012 was $26.8 million, as compared to $51.8 million for the same period in 2011. The decrease in net income was due to a decrease in gain on financial derivative contracts, charge on redemption of long-term debt and higher depletion and depreciation.

Net income for the nine months ended September 30, 2012 was $227.0 million, as compared to $159.7 million for the same period in 2011. The increase in net income was primarily the result of a $172.8 million gain on disposition of U.S. properties and increase in gain on financial derivative contracts, offset by charge on redemption of long-term debt, higher income tax expense and higher depletion and depreciation.

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 that 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 $16.4 million balance of accumulated other comprehensive loss at September 30, 2012 is the sum of a $3.5 million foreign currency translation loss incurred as at December 31, 2011 and a $12.9 million foreign currency translation loss related to the nine months ended September 30, 2012.

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, 2012	June 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011
Cash flow from operating activities	$ 142,368	$ 122,701	$ 148,678	$ 416,430	$ 414,777
Change in non-cash working capital	6,497	11,594	1,758	16,210	1,553
Asset retirement expenditures	1,205	377	3,064	2,353	4,942
Financing costs	(12,862)	(11,794)	(10,383)	(34,955)	(33,738)
Accretion on asset retirement obligations	1,663	1,652	1,558	4,942	4,558
Accretion on debentures and long term debt	173	162	150	492	418
Funds from operations	$ 139,044	$ 124,692	$ 144,825	$ 405,472	$ 392,510
Cash dividends declared	$ 79,622	$ 78,908	$ 69,916	$ 236,895	$ 208,135
Reinvested dividends	26,982	26,965	19,646	76,753	53,100
Cash dividends declared (net of DRIP)	$ 52,640	$ 51,943	$ 50,270	$ 160,142	$ 155,035
Payout ratio	57%	63%	48%	58%	53%
Payout ratio (net of DRIP)	38%	42%	35%	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, it is not possible 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 $52.6 million for the third quarter of 2012 were funded through funds from operations of $139.0 million. Cash dividends declared, net of DRIP participation, of $160.1 million for the nine months ended September 30, 2012 were funded through funds from operations of $405.5 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, 2012	December 31, 2011
Bank loan	$ 181,785	$ 311,960
Long-term debt[(1)]	447,555	302,550
Working capital (surplus) deficiency	(149,329)	36,071
Total monetary debt	**$ 480,011**	$ 650,581

(1) Principal amount of instruments.

At September 30, 2012, total monetary debt was $480.0 million, as compared to $650.6 million at December 31, 2011. Bank borrowings at September 30, 2012 were $181.8 million, as compared to total credit facilities of $700 million.

Our wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40 million extendible operating loan facility with a chartered bank and a $660 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 or 3 year period (subject to a maximum three-year term at any time). On June 12, 2012, the maturity date of the credit facilities was extended by one year to 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 during the three-year term. 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 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 and related amendments are accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011 and July 10, 2012).

The weighted average interest rate on the bank loan for nine months ended September 30, 2012 was 3.29% (3.69% for year ended December 31, 2011 and 3.45% for the nine months ended September 30, 2011).

On February 17, 2011, we issued US$150 million principal amount of Series B senior unsecured debentures bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. 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 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)	2012	2011	2012	2011
Land	$ 3,813	$ (463)	$ 10,600	$ 4,088
Seismic	795	211	2,337	379
Drilling and completion	81,534	67,042	246,125	203,981
Equipment	26,935	33,632	92,821	87,404
Other	49	(54)	56	(17)
Total exploration and development	$ 113,126	$ 100,368	$ 351,939	$ 295,835
Acquisitions – Corporate	–	22	–	118,693
Acquisitions – Properties	958	28,502	13,467	65,835
Proceeds from divestitures	1,202	–	(316,200)	–
Total acquisitions and divestitures	2,160	28,524	(302,733)	184,528
Total oil and natural gas expenditures	115,286	128,892	49,206	480,363
Other plant and equipment, net	2,454	591	9,121	1,416
Total capital expenditures	$ 117,740	$ 129,483	$ 58,327	$ 481,779

On May 22, 2012, Baytex Energy USA Ltd. ("Baytex USA"), an indirect, wholly-owned subsidiary, disposed of its non-operated interests in North Dakota, which consisted of $119.4 million of oil and gas properties and $21.6 million of exploration and evaluation assets, for net cash proceeds of $313.8 million. Gains totaling $172.8 million were recognized in the statements of income and comprehensive income.

The net cash proceeds from the disposition were deposited into an escrow account in accordance with Section 1031 of the United States Internal Revenue Code, which provides the ability to defer in whole or in part the payment of federal income taxes on a gain on disposition in the event that the sale proceeds are redeployed into a replacement property which is identified within 45 days of closing of the disposition and ultimately acquired within 180 days of the closing of the disposition. As at September 30, 2012 US$199.5 million was held in the escrow account. In the event that a replacement property is not acquired by November 18, 2012, the remaining escrowed funds will be returned to Baytex USA.

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 November 7, 2012, the Company had 121,221,595 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, 2012, 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	**$ 219,246**	$ 219,246	$ –	$ –	$ –
Dividends payable to shareholders	**26,612**	26,612	–	–	–
Bank loan[(1)]	**181,785**	–	181,785	–	–
Long-term debt[(2)]	**447,555**	–	–	–	447,555
Operating leases	**47,003**	5,873	12,564	12,334	16,232
Processing agreements	**67,265**	1,399	8,917	10,762	46,187
Transportation agreements	**66,063**	1,791	10,987	16,655	36,630
Total	**$1,055,529**	$ 254,921	$ 214,253	$ 39,751	$ 546,604

(1) The bank loan is a covenant-based revolving loan that is extendible annually for a one, two or three year period (subject to a maximum three-year term at any time). Unless extended, the revolving period will end on June 14, 2015 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, 2012 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2012			2011				2010
($ thousands, except per common share or trust unit amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Gross revenues	**299,786**	284,248	343,355	367,813	313,787	336,899	290,315	263,497
Net income	**26,773**	157,280	42,958	57,780	51,839	106,863	950	21,356
Per common share or trust unit – basic	**0.22**	1.32	0.36	0.49	0.45	0.92	0.01	0.19
Per common share or trust unit – diluted	**0.22**	1.30	0.36	0.48	0.44	0.90	0.01	0.18

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: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and natural gas operations; changes in royalty rates and incentive programs relating to the oil and natural gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; failure to obtain the necessary regulatory and other approvals on the planned timelines 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, 2011, 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, 2012	December 31, 2011
ASSETS		
Current assets		
Cash (note 4)	$ 197,730	$ 7,847
Trade and other receivables	196,274	206,951
Crude oil inventory	1,183	898
Financial derivatives	23,895	10,879
	419,082	226,575
Non-current assets		
Deferred income tax asset	–	10,133
Financial derivatives	909	180
Exploration and evaluation assets (note 3)	112,094	129,774
Oil and gas properties (note 4)	2,052,018	2,032,160
Other plant and equipment	32,004	25,233
Goodwill	37,755	37,755
	$ 2,653,862	$ 2,461,810
LIABILITIES		
Current liabilities		
Trade and other payables	$ 219,246	$ 225,831
Dividends payable to shareholders	26,612	25,936
Financial derivatives	11,036	25,205
	256,894	276,972
Non-current liabilities		
Bank loan (note 5)	181,785	311,960
Long-term debt (note 6)	439,455	297,731
Asset retirement obligations (note 7)	270,318	260,411
Deferred income tax liability	190,258	93,217
Financial derivatives	8,349	14,785
	1,347,059	1,255,076
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 8)	1,822,959	1,680,184
Contributed surplus	65,771	85,716
Accumulated other comprehensive loss	(16,423)	(3,546)
Deficit	(565,504)	(555,620)
	1,306,803	1,206,734
	$ 2,653,862	$ 2,461,810

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
Revenues, net of royalties (note 12)	$ 252,028	$ 263,131	$ 780,617	$ 790,384
Expenses				
Production and operating	57,093	55,936	172,347	153,601
Transportation and blending	44,426	54,059	153,953	185,737
Exploration and evaluation (note 3)	2,553	3,285	9,483	10,102
Depletion and depreciation	71,642	63,406	214,534	176,519
General and administrative	9,914	9,604	32,239	29,423
Share-based compensation (note 9)	9,759	9,841	28,960	25,177
Financing costs (note 13)	12,862	10,383	34,955	33,738
Gain on financial derivatives (note 15)	(1,434)	(37,243)	(47,956)	(33,585)
Foreign exchange (gain) loss (note 14)	(6,248)	19,839	(4,236)	11,903
Loss (gain) on divestiture of oil and gas properties (note 4)	2,654	(1,603)	(172,752)	(1,603)
Charge on redemption of long-term debt (note 6)	9,261	–	9,261	–
	212,482	187,507	430,788	591,012
Net income before income taxes	39,546	75,624	349,829	199,372
Income tax expense (note 11)				
Current income tax (recovery) expense	(3,035)	–	13,629	–
Deferred income tax expense	15,808	23,785	109,189	39,720
	12,773	23,785	122,818	39,720
Net income attributable to shareholders	$ 26,773	$ 51,839	$ 227,011	$ 159,652
Other comprehensive income (loss)				
Foreign currency translation adjustment	(14,445)	19,425	(12,877)	12,777
Comprehensive income	$ 12,328	$ 71,264	$ 214,134	$ 172,429
Net income per common share (note 10)				
Basic	$ 0.22	$ 0.45	$ 1.90	$ 1.38
Diluted	$ 0.22	$ 0.44	$ 1.87	$ 1.35
Weighted average common shares (note 10)				
Basic	120,469	116,404	119,476	115,477
Diluted	121,893	118,918	121,291	118,478

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	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2010	$ 1,484,335	$ 129,129	$ (10,323)	$ (492,005)	**$ 1,111,136**
Dividends to shareholders	–	–	–	(208,135)	**(208,135)**
Exercise of share rights	92,084	(58,458)	–	–	**33,626**
Share-based compensation	–	25,177	–	–	**25,177**
Issued pursuant to dividend reinvestment plan	51,470	–	–	–	**51,470**
Comprehensive income for the period	–	–	12,777	159,652	**172,429**
Balance at September 30, 2011	$ 1,627,889	$ 95,848	$ 2,454	$ (540,488)	**$ 1,185,703**
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 (loss) 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**

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)	2012	2011	2012	2011
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income for the period	$ 26,773	$ 51,839	$ 227,011	$ 159,652
Adjustments for:				
Share-based compensation (note 9)	9,759	9,841	28,960	25,177
Unrealized foreign exchange (gain) loss (note 14)	(5,346)	24,257	(3,234)	14,655
Exploration and evaluation	2,553	2,608	9,483	7,562
Depletion and depreciation	71,642	63,406	214,534	176,519
Unrealized loss (gain) on financial derivatives (note 15)	7,139	(31,016)	(36,043)	(34,148)
Loss (gain) on divestiture of oil and gas properties (note 4)	2,654	(1,603)	(172,752)	(1,603)
Current income tax expense on divestiture	(3,035)	–	13,629	–
Deferred income tax expense	15,808	23,785	109,189	39,720
Charge on redemption of long-term debt (note 6)	9,261	–	9,261	–
Financing costs (note 13)	12,862	10,383	34,955	33,738
Change in non-cash working capital	(6,497)	(1,758)	(16,210)	(1,553)
Asset retirement obligations (note 7)	(1,205)	(3,064)	(2,353)	(4,942)
	142,368	148,678	416,430	414,777
Financing activities				
Payments of dividends	(51,458)	(52,037)	(160,813)	(156,056)
(Decrease) increase in bank loan	(214,035)	39,694	(130,175)	56,448
Proceeds from issuance of long-term debt (note 6)	293,761	–	293,761	145,810
Redemption of long-term debt (note 6)	(156,863)	–	(156,863)	–
Issuance of common shares (note 8)	3,399	5,148	18,463	33,626
Interest paid	(14,169)	(14,982)	(32,397)	(31,370)
	(139,365)	(22,177)	(168,024)	48,458
Investing activities				
Additions to exploration and evaluation assets (note 3)	(4,402)	(566)	(12,096)	(8,010)
Additions to oil and gas properties	(108,724)	(99,802)	(339,843)	(287,825)
Property acquisitions	(958)	(28,502)	(13,467)	(65,835)
Corporate acquisitions	–	(22)	–	(118,693)
Proceeds from divestitures (note 4)	(1,202)	–	316,200	–
Current income tax expense on divestiture	3,035	–	(13,629)	–
Additions to other plant and equipment, net of disposals	(2,454)	(591)	(9,121)	(1,416)
Change in non-cash working capital	3,716	1,260	20,558	18,577
	(110,989)	(128,223)	(51,398)	(463,202)
Impact of foreign currency translation on cash balances	(6,750)	(337)	(7,125)	(33)
Change in cash	(114,736)	(2,059)	189,883	–
Cash, beginning of period	312,466	2,059	7,847	–
Cash, end of period	$ 197,730	$ –	$ 197,730	$ –

See accompanying notes to the condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at September 30, 2012, December 31, 2011 *and for the three months and nine months ended September 30, 2012 and 2011*

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

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2011. The Company's accounting policies are unchanged compared to December 31, 2011 and the use of estimates and judgments is also consistent with the December 31, 2011 financial statements.

The consolidated financial statements were approved and authorized by the Board of Directors on November 12, 2012.

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, 2010	**$ 113,082**
Capital expenditures	9,104
Corporate acquisition	14,944
Property acquisition	18,013
Exploration and evaluation expense	(10,130)
Transfer to oil and gas properties	(14,398)
Divestitures	(2,058)
Foreign currency translation	1,217
As at December 31, 2011	**$ 129,774**
Capital expenditures	12,096
Property acquisition	10,543
Exploration and evaluation expense	(9,483)
Transfer to oil and gas properties	(7,493)
Divestitures	(22,118)
Foreign currency translation	(1,225)
As at September 30, 2012	**$ 112,094**

Subsequent to the end of the third quarter, Baytex Energy Ltd. ("Baytex Energy"), a wholly-owned subsidiary of Baytex, acquired undeveloped oil sands leases in the Cold Lake area of Alberta for a total purchase price of $120 million.

4. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2010	**$ 1,819,351**
Capital expenditures	364,578
Corporate acquisition	131,635
Property acquisitions	61,137
Transferred from exploration and evaluation assets	14,398
Change in asset retirement obligations	84,879
Divestitures	(10,233)
Foreign currency translation	5,674
As at December 31, 2011	**$ 2,471,419**
Capital expenditures	339,843
Property acquisitions	2,924
Transferred from exploration and evaluation assets	7,493
Change in asset retirement obligations	7,384
Divestitures	(134,419)
Foreign currency translation	(4,470)
As at September 30, 2012	**$ 2,690,174**

Accumulated depletion	
As at December 31, 2010	**$ 194,722**
Depletion for the period	244,893
Divestitures	(667)
Foreign currency translation	311
As at December 31, 2011	**$ 439,259**
Depletion for the period	212,193
Divestitures	(13,089)
Foreign currency translation	(207)
As at September 30, 2012	**$ 638,156**

Carrying value	
As at December 31, 2011	**$ 2,032,160**
As at September 30, 2012	**$ 2,052,018**

On May 22, 2012, Baytex Energy USA Ltd. ("Baytex USA"), an indirect, wholly-owned subsidiary of Baytex, disposed of its non-operated interests in North Dakota, which consisted of $119.4 million of oil and gas properties and $21.6 million of exploration and evaluation assets, for net cash proceeds of $313.8 million. Gains totaling $172.8 million were recognized in the statements of income and comprehensive income.

The net cash proceeds from the disposition were deposited into an escrow account in accordance with Section 1031 of the United States Internal Revenue Code, which provides the ability to defer in whole or in part the payment of federal income taxes on a gain on disposition in the event that the sale proceeds are redeployed into a replacement property which is identified within 45 days of closing of the disposition and ultimately acquired within 180 days of the closing of the disposition. As at September 30, 2012, US$199.5 million was held in the escrow account. In the event that a replacement property is not acquired by November 18, 2012, the remaining escrowed funds will be returned.

5. BANK LOAN

As at	September 30, 2012	December 31, 2011
Bank loan	$ 181,785	$ 311,960

Baytex Energy has established a $40.0 million extendible operating loan facility with a chartered bank and a $660.0 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 or 3 year period (subject to a maximum three-year term at any time). On June 12, 2012, the maturity date of the credit facilities was extended by one year to June 14, 2015. The credit facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments during the three-year term. 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 the nine months ended September 30, 2012 include facility amendment fees of $0.8 million ($2.2 million for the nine months ended September 30, 2011). The weighted average interest rate on the bank loan for nine months ended September 30, 2012 was 3.29% (3.45% for the nine months ended September 30, 2011).

6. LONG-TERM DEBT

As at	September 30, 2012	December 31, 2011
9.15% Series A senior unsecured debentures (Cdn$150,000 – principal)	$ –	$ 147,328
6.75% Series B senior unsecured debentures (US$150,000 – principal)	145,604	150,403
6.625% Series C senior unsecured debentures (Cdn$300,000 – principal)	293,851	–
	$ 439,455	$ 297,731

On July 19, 2012, Baytex issued $300.0 million principal amount of Series C senior unsecured debentures bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. These debentures are subordinate to Baytex Energy's bank credit facilities. After July 19 of each of the following years, these debentures are redeemable at the Company's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2017 at 103.313%, 2018 at 102.208%, 2019 at 101.104%, and 2020 at 100%. These notes are carried at amortized cost, net of a $6.2 million transaction cost. These notes accrete up to the principal balance at maturity using the effective interest rate of 6.9%.

On August 26, 2012, Baytex redeemed its 9.15% Series A senior unsecured debentures ($150 million principal amount) for 104.575% of the principal amount. A charge on redemption of $9.3 million has been recorded for the three months and nine months ended September 30, 2012, consisting of $6.9 million premium paid to redeem the debentures and $2.4 million of unaccreted debt issue costs has been recorded for the three and nine months ended September 30, 2012.

Accretion expense on debentures of $0.2 million has been recorded for the three months ended September 30, 2012 (three months ended September 30, 2011 – $0.1 million) and $0.5 million for the nine months ended September 30, 2012 (nine months ended September 30, 2011 – $0.4 million).

7. ASSET RETIREMENT OBLIGATIONS

	September 30, 2012	December 31, 2011
Balance, beginning of period	$ 260,411	$ 169,611
Liabilities incurred	6,207	5,834
Liabilities settled	(2,353)	(10,588)
Liabilities acquired	–	5,003
Liabilities divested	(1,554)	(556)
Accretion	4,942	6,185
Change in estimate(1)	2,731	84,879
Foreign currency translation	(66)	43
Balance, end of period	$ 270,318	$ 260,411

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

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The undiscounted amount of estimated cash flow required to settle the asset retirement obligations using an estimated annual inflation rate of 2.0% at September 30, 2012 is $322.0 million (December 31, 2011 – $315.9 million). The amount of estimated cash flow required to settle the asset retirement obligations using an estimated annual inflation rate of 2.0% and discounted at a risk free rate of 2.5% at September 30, 2012 (December 31, 2011 – 2.5%) is $270.3 million (December 31, 2011 – $260.4 million).

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, 2012, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000's)*	Amount
Balance, December 31, 2010	**113,712**	**$ 1,484,335**
Issued on exercise of share rights	2,665	45,048
Transfer from contributed surplus on exercise of share rights	–	77,258
Issued pursuant to dividend reinvestment plan	1,516	73,543
Balance, December 31, 2011	**117,893**	**$ 1,680,184**
Issued on exercise of share rights	1,073	18,463
Transfer from contributed surplus on exercise of share rights	–	28,857
Transfer from contributed surplus on vesting and conversion of share awards	390	20,048
Issued pursuant to dividend reinvestment plan	1,606	75,407
Balance, September 30, 2012	**120,962**	**$ 1,822,959**

Monthly dividends of $0.22 per common share were declared by the Company during the three and nine months ended September 30, 2012 for total dividends declared of $79.6 million and $236.9 million, respectively.

Subsequent to September 30, 2012, the Company announced that a monthly dividend in respect of October 2012 operations of $0.22 per common share totaling $26.7 million will be payable on November 15, 2012 to shareholders of record on October 31, 2012.

9. EQUITY BASED PLANS

Share Rights Plan

As a result of the conversion of the legal structure of Baytex Energy Trust (the "Trust") from an income trust to a corporation at year-end 2010, all outstanding rights to acquire trust units of the Trust were exchanged for equivalent rights to acquire common shares of Baytex ("share rights"), which are governed by the terms of the Common Share Rights Incentive Plan (the "Share Rights Plan"). As a result of the adoption of the Share Award Incentive Plan (as described below) 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, cancelled or expired.

Baytex recorded compensation expense related to the share rights under the Share Rights Plan of $1.0 million for the three months ended September 30, 2012 (three months ended September 30, 2011 – $3.9 million) and $2.2 million for the nine months ended September 30, 2012 (nine months ended September 30, 2011 – $13.7 million).

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

	Number of share rights *(000's)*	Weighted average exercise price
Balance, December 31, 2010(1)	**5,761**	**$ 17.02**
Exercised(2)	(2,665)	16.92
Forfeited(1)	(125)	23.05
Balance, December 31, 2011(1)	**2,971**	**$ 16.98**
Exercised(2)	(1,073)	17.32
Forfeited(1)	(79)	21.12
Balance, September 30, 2012(1)	**1,819**	**$ 16.57**

(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, 2012:

	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, 2012 *(000's)*	Weighted Average Grant Price	Weighted Average Remaining Term *(years)*	Number Exercisable at September 30, 2012 *(000's)*	Weighted Average Exercise Price	Number Outstanding at September 30, 2012 *(000's)*	Weighted Average Exercise Price	Weighted Average Remaining Term *(years)*	Number Exercisable at September 30, 2012 *(000's)*	Weighted Average Exercise Price
$4.90 to $12.50	5	$ 12.46	1.5	5	$ 12.46	720	$ 9.29	0.9	720	$ 9.29
$12.51 to $19.50	609	17.97	1.0	609	17.97	202	16.65	1.5	201	16.65
$19.51 to $26.50	290	20.83	0.9	289	20.82	789	21.38	2.2	459	21.36
$26.51 to $33.50	874	27.91	2.2	514	27.87	92	28.78	2.4	47	28.09
$33.51 to $40.50	38	35.71	2.9	16	34.91	15	34.60	2.8	7	34.47
$40.51 to $47.72	3	45.02	3.2	1	45.19	1	43.51	3.3	–	43.51
$4.90 to $47.72	1,819	$ 23.60	1.6	1,434	$ 22.28	1,819	$ 16.57	1.6	1,434	$ 14.93

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 plan of the Company, including the Share Rights Plan) shall not at any time exceed 10% of the then issued and outstanding common shares.

The Company recorded compensation expense related to the share awards of $8.8 million for the three months ended September 30, 2012 (three months ended September 30, 2011 – $5.9 million) and $26.8 million for the nine months ended September 30, 2012 (nine months ended September 30, 2011 – $11.5 million).

The fair value of share awards is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate, which has been estimated at 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 $51.52 per restricted award and performance award granted during the nine months ended September 30, 2012 (nine months ended September 30, 2011 – $50.71 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000's)*	Number of performance awards *(000's)*	Number of share awards *(000's)*
Balance, December 31, 2010	**–**	**–**	**–**
Granted	389	243	632
Forfeited	(24)	(14)	(38)
Balance, December 31, 2011	**365**	**229**	**594**
Granted	339	258	597
Vested and converted to common shares	(126)	(127)	(253)
Forfeited	(32)	(16)	(48)
Balance, September 30, 2012	**546**	**344**	**890**

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 rights were exercised and share awards were converted. The treasury stock method is used to determine the dilutive effect of share rights and share awards whereby any proceeds from the exercise of share rights and the conversion of share awards or other dilutive instruments 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, 2012			Three Months Ended September 30, 2011		
	Net income	Common Shares (000's)	Net income per share	Net income	Common Shares (000's)	Net income per share
Net income – basic	$ 26,773	120,469	$ 0.22	$ 51,839	116,404	$ 0.45
Dilutive effect of share rights	–	958		–	2,303	
Dilutive effect of share awards	–	466		–	211	
Net income – diluted	$ 26,773	121,893	$ 0.22	$ 51,839	118,918	$ 0.44

For the three months ended September 30, 2012, and 2011, no share rights were anti-dilutive.

	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
	Net income	Common Shares (000's)	Net income per share	Net income	Common Shares (000's)	Net income per share
Net income – basic	$ 227,011	119,476	$ 1.90	$ 159,652	115,477	$ 1.38
Dilutive effect of share rights	–	1,214		–	2,808	
Dilutive effect of share awards	–	601		–	193	
Net income – diluted	$ 227,011	121,291	$ 1.87	$ 159,652	118,478	$ 1.35

For the nine months ended September 30, 2012, and 2011, no share rights were anti-dilutive.

11. INCOME TAXES

The provision for (recovery of) income taxes has been computed as follows:

	Nine months ended September 30	
	2012	2011
Net income before income taxes	$ 349,829	$ 199,372
Expected income taxes at the statutory rate of 25.45% (2011 – 26.97%)(1)	89,031	53,771
Increase (decrease) in income taxes resulting from:		
Non-taxable portion of foreign exchange loss (gain)	(993)	2,105
Share-based compensation	7,369	6,790
Effect of change in income tax rates	(1,002)	(4,629)
Effect of rate adjustments for foreign jurisdictions	22,357	(2,489)
Effect of change in opening tax pool balances	3,680	(14,817)
Other	2,376	(1,011)
Income tax expense	$ 122,818	$ 39,720

(1) The change in statutory rate is related to a legislated reduction in the Canadian federal corporate income tax rate and changes in the provincial apportionment of income.

12. REVENUES

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
Petroleum and natural gas revenues	$ 298,953	$ 313,247	$ 924,740	$ 938,850
Royalty charges	(47,758)	(50,656)	(146,772)	(150,617)
Royalty income	833	540	2,649	2,151
Revenues, net of royalties	$ 252,028	$ 263,131	$ 780,617	$ 790,384

13. FINANCING COSTS

Baytex incurred financing costs on its outstanding liabilities as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
Bank loan and other	$ 2,488	$ 2,583	$ 8,172	$ 9,389
Long-term debt	8,700	6,088	20,981	16,793
Accretion on asset retirement obligations	1,663	1,558	4,942	4,558
Debt financing costs	11	154	860	2,998
Financing costs	$ 12,862	$ 10,383	$ 34,955	$ 33,738

14. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
Unrealized foreign exchange (gain) loss	$ (5,346)	$ 24,257	$ (3,234)	$ 14,655
Realized foreign exchange gain	(902)	(4,418)	(1,002)	(2,752)
Foreign exchange (gain) loss	$ (6,248)	$ 19,839	$ (4,236)	$ 11,903

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

At September 30, 2012, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	November 2011 to October 2013	US$1.00 million	1.0433	(1)
Monthly average rate forward	Calendar 2012	US$1.25 million	1.0209	(2)
Monthly spot collar	Calendar 2012	US$0.75 million	0.9524 - 1.0503	(1)
Monthly spot collar	Calendar 2012	US$0.25 million	1.0200 - 1.0700	(1)
Monthly average collar	Calendar 2012	US$0.25 million	0.9700 - 1.0310	(1)
Monthly average collar	Calendar 2012	US$0.50 million	0.9750 - 1.0305	(1)
Monthly average collar	Calendar 2012	US$0.50 million	0.9900 - 1.0805	(2)
Monthly average collar	Calendar 2012	US$0.75 million	1.0225 - 1.0425	(1)
Monthly average collar	Calendar 2012	US$0.25 million	1.0295 - 1.0545	(1)
Monthly spot collar	Calendar 2012	US$1.00 million	0.9800 - 1.0722	(1)
Monthly spot collar	Calendar 2012	US$1.00 million	0.9900 - 1.0720	(1)
Monthly spot collar	Calendar 2012	US$0.50 million	0.9900 - 1.0785	(1)
Monthly forward spot sale	October 2012 to December 2012	US$4.50 million	1.0065	(2)
Monthly spot collar	June 2012 to December 2012	US$1.00 million	0.9900 - 1.0720	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0000 - 1.0725	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0100 - 1.0720	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0200 - 1.0575	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0200 - 1.0655	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0250 - 1.0702	(1)
Monthly average collar	June 2012 to December 2013	US$2.00 million	1.0300 - 1.0650	(1)
Monthly forward spot sale	Calendar 2013	US$5.50 million	1.0007	(2)
Monthly average rate forward	Calendar 2013	US$0.25 million	1.0023	(1)
Monthly average collar	Calendar 2013	US$0.25 million	0.9700 - 1.0310	(1)

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

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, 2012	December 31, 2011	**September 30, 2012**	December 31, 2011
U.S. dollar denominated	**US$339,548**	US$107,138	**US$213,307**	US$402,979

Interest Rate Risk

As at September 30, 2012, 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	September 27, 2011 to September 27, 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, receive floating	September 25, 2012 to September 25, 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, 2012, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Time spread	January to December 2012	500 bbl/d	Dec 2014 plus US$3.25	WTI
Time spread	January to December 2012	500 bbl/d	Dec 2014 plus US$0.65	WTI
Price collar	March to December 2012	200 bbl/d	US$97.00 – US$117.60	WTI
Price collar	March to December 2012	300 bbl/d	US$97.00 – US$116.60	WTI
Fixed – Sell	October to December 2012	13,450 bbl/d	US$97.30	WTI
Fixed – Sell	October to December 2012(2)	1,000 bbl/d	US$96.10	WTI
Price collar	Calendar 2012	400 bbl/d	US$98.00 – US$104.52	WTI
Price collar	Calendar 2012	300 bbl/d	US$100.00 – US$104.90	WTI
Price collar	Calendar 2012	200 bbl/d	US$97.50 – US$104.25	WTI
Price collar	Calendar 2012	300 bbl/d	US$100.00 – US$105.92	WTI
Fixed – Buy	Calendar 2012	200 bbl/d	US$102.50	WTI
Fixed – Buy	January to June 2013	250 bbl/d	US$102.07	WTI
Fixed – Sell	January to June 2013(4)	1,000 bbl/d	US$102.05	WTI
Fixed – Sell	January to June 2013(4)	1,000 bbl/d	US$104.10	WTI
Fixed – Sell	January to June 2013(4)	2,000 bbl/d	US$103.80	WTI
Fixed – Buy	July to December 2013	350 bbl/d	US$101.70	WTI
Fixed – Sell	July to December 2013(4)	1,000 bbl/d	US$104.70	WTI
Fixed – Sell	Calendar 2013	2,500 bbl/d	US$99.18	WTI
Fixed – Sell	Calendar 2013(3)	1,500 bbl/d	US$96.00	WTI
Fixed – Sell	Calendar 2013(3)	1,000 bbl/d	US$98.00	WTI
Fixed – Buy	Calendar 2014	380 bbl/d	US$101.06	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Counterparty has the option to increase the volumes by 1,000 bbl/d.
(3) Counterparty has the option to double the volumes on the contract.
(4) Counterparty has the option to extend the term by six months.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.328	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.390	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.370	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.450	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.430	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.410	AECO
Basis swap	Calendar 2012	1,500 mmBtu/d	NYMEX less US$0.490	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.515	AECO
Basis swap	Calendar 2012	2,000 mmBtu/d	NYMEX less US$0.520	AECO
Basis swap	Calendar 2012	2,500 mmBtu/d	NYMEX less US$0.530	AECO
Sold call	Calendar 2012	6,000 mmBtu/d	US$5.25	NYMEX
Fixed – Sell	October to December 2012	13,000 mmBtu/d	US$4.04	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	
	2012	2011	2012	2011
Realized (gain) loss on financial derivatives	$ (8,573)	$ (6,227)	$ (11,913)	$ 563
Unrealized loss (gain) on financial derivatives	7,139	(31,016)	(36,043)	(34,148)
Gain on financial derivatives	$ (1,434)	$ (37,243)	$ (47,956)	$ (33,585)

Subsequent to September 30, 2012, Baytex added the following financial derivative contracts:

Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	Calendar 2013	2,000 GJ/d	$3.37	AECO
Fixed – Sell	Calendar 2013	2,000 mmBtu/d	US$4.02	NYMEX
Fixed – Sell	Calendar 2013	1,000 mmBtu/d	US$4.05	NYMEX
Fixed – Sell	Calendar 2013	1,000 mmBtu/d	US$4.07	NYMEX
Fixed – Sell	Calendar 2013	1,000 mmBtu/d	US$4.10	NYMEX
Basis swap	Calendar 2013	2,000 mmBtu/d	NYMEX less US$0.375	AECO
Basis swap	Calendar 2013	1,000 mmBtu/d	NYMEX less US$0.388	AECO
Basis swap	Calendar 2013	2,000 mmBtu/d	NYMEX less US$0.428	AECO
Fixed – Sell	January to December 2014	2,000 mmBtu/d	US$4.45	NYMEX

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

Physical Delivery Contracts

At September 30, 2012, the following physical delivery contracts were entered into and continue to be 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 2011 to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	October to December 2012	5,500 bbl/d	WTI less US$18.18
WCS Blend	November 2012	2,000 bbl/d	WTI less US$15.75
WCS Blend	November to December 2012	1,000 bbl/d	WTI less US$15.38
WCS Blend	December 2012	1,000 bbl/d	WTI less US$17.50
WCS Blend	January to June 2013	1,250 bbl/d	WTI × 80.00%
WCS Blend	January to June 2013	4,250 bbl/d	WTI less US$18.18
WCS Blend	July to December 2013	2,750 bbl/d	WTI × 80.00%
WCS Blend	July 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	April 2012 to March 2013	640 bbl/d	WTI plus US$6.70
Fixed – Buy	January 2013 to December 2013	160 bbl/d	WTI plus US$3.10

At September 30, 2012, Baytex had committed to deliver the volumes of raw bitumen noted below to market on railways:

Heavy Oil	Period	Term Volume
Raw bitumen	October to December 2012	7,000 bbl/d
Raw bitumen	January to March 2013	8,500 bbl/d
Raw bitumen	April to June 2013	6,000 bbl/d
Raw bitumen	July to September 2013	3,000 bbl/d
Raw bitumen	October to December 2013	3,000 bbl/d

16. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

On August 4, 2011, Baytex filed a Short Form Base Shelf Prospectus with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the “Shelf Prospectus”). The Shelf Prospectus allows Baytex to offer and issue common shares, subscription receipts, warrants, options and debt securities by way of one or more prospectus supplements at any time during the 25-month period that the Shelf Prospectus remains in place. The securities may be issued from time to time, at the discretion of Baytex, with an aggregate offering amount not to exceed $500 million (Canadian).

On July 19, 2012, Baytex issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par. The offering was made by way of a prospectus supplement dated July 10, 2012 to the Shelf Prospectus.

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, 2012, and December 31, 2011 and for the three months and nine months ended September 30, 2012 and 2011 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, 2012					
Current assets	$ –	$ 418,937	$ 145	$ –	$ 419,082
Intercompany advances and investments	1,792,406	(569,563)	82,735	(1,305,578)	–
Non-current assets	2,435	2,232,345	–	–	2,234,780
Current liabilities	31,779	225,011	104	–	256,894
Bank loan and long-term debt	439,455	181,785	–	–	621,240
Asset retirement obligation and other non-current liabilities	$ –	$ 468,925	$ –	$ –	$ 468,925
As at December 31, 2011					
Current assets	$ 351	$ 225,850	$ 374	$ –	$ 226,575
Intercompany advances and investments	1,753,047	(515,492)	72,787	(1,310,342)	–
Non-current assets	2,435	2,232,800	–	–	2,235,235
Current liabilities	34,502	242,303	167	–	276,972
Bank loan and long-term debt	297,731	311,960	–	–	609,691
Asset retirement obligation and other non-current liabilities	$ –	$ 368,413	$ –	$ –	$ 368,413
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 unit-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, 2011					
Revenues, net of royalties	$ 16,059	$ 791,767	$ 6,335	$ (23,777)	$ 790,384
Production, operation and exploration	–	163,703	–	–	163,703
Transportation and blending	–	185,737	–	–	185,737
General, administrative and share-based compensation	1,206	54,393	126	(1,125)	54,600
Financing, derivatives, foreign exchange and other (gains)/losses	24,597	8,556	(48)	(22,652)	10,453
Depletion and depreciation	–	176,519	–	–	176,519
Income tax expense	(1,298)	41,018	–	–	39,720
Net income (loss)	$ (8,446)	$ 161,841	$ 6,257	$ –	$ 159,652
For the three months ended September 30, 2011					
Revenues, net of royalties	$ 5,878	$ 263,506	$ 2,602	$ (8,855)	$ 263,131
Production, operation and exploration	–	59,221	–	–	59,221
Transportation and blending	–	54,059	–	–	54,059
General, administrative and unit-based compensation	437	19,373	10	(375)	19,445
Financing, derivatives, foreign exchange and other (gains)/losses	17,226	(17,360)	(10)	(8,480)	(8,624)
Depletion and depreciation	–	63,406	–	–	63,406
Income tax expense	(1,362)	25,147	–	–	23,785
Net income (loss)	$ (10,423)	$ 59,660	$ 2,602	$ –	$ 51,839

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
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)
(Decrease) 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	$ –	$ (7,125)	$ –	$ –	$ (7,125)

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
For the nine months ended September 30, 2011					
Cash provided by (used in):					
Operating activities	$ 195,502	$ 218,854	$ 421	$ –	$ 414,777
Receipt (payment) of dividends	(156,056)	258	(258)	–	(156,056)
Increase in bank loan	–	56,448	–	–	56,448
Change in intercompany loans	(193,414)	248,826	(55,412)	–	–
Increase in investments	145,810	–	–	–	145,810
Proceeds from issuance of long-term debt	33,626	–	55,249	(55,249)	33,626
Increase in equity	(25,468)	(5,902)	–	–	(31,370)
Interest paid	195,502	218,854	421	–	414,777
Financing activities	–	518,484	–	(55,249)	463,235
Additions to exploration and evaluation assets	–	(8,010)	–	–	(8,010)
Additions to oil and gas properties	–	(287,825)	–	–	(287,825)
Property acquisitions	–	(65,835)	–	–	(65,835)
Corporate acquisitions	–	(118,693)	–	–	(118,693)
Additions to other plant and equipment, net of disposals	–	(1,416)	–	–	(1,416)
Change in non-cash working capital	–	18,577	–	–	18,577
Investing activities	–	(463,202)	–	–	(463,202)
Impact of foreign currency translation on cash balances	$ –	$ (33)	$ –	$ –	$ (33)

ABBREVIATIONS

AcSB	Accounting Standards Board
AECO	the natural gas storage facility located at Suffield, Alberta
ASC	Accounting Standards Codification
bbl	barrel
bbl/d	barrel per day
bcf	billion cubic feet
*boe**	barrels of oil equivalent
*boe/d**	barrels of oil equivalent per day
CSS	cyclic steam stimulation
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
LLB	Lloyd Light Blend
LLK	Lloyd Kerrobert
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbl	million barrels
*mmboe**	million barrels of oil equivalent
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MW	Megawatt
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SAGD	steam-assisted gravity drainage
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *BOEs may be misleading, particularly if used in isolation. 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 (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

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

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Gregory K. Melchin (1)
Independent Businessman

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

HEAD OFFICE

Centennial Place, East Tower
Suite 2800, 520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3
T 587-952-3000
F 587-952-3001
Toll-free: 1-800-524-5521
www.baytex.ab.ca

AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
Alberta Treasury Branches
Bank of America
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 of California
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

Stephen Brownridge
Vice President, Exploration

Geoffrey J. Darcy
Vice President, Marketing

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

Brian G. Ector
Vice President, Investor Relations

Michael S. Kaluza
Vice President, Corporate Development and
Planning

Brett J. McDonald
Vice President, Land

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

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

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