BAYTEX ENERGY CORP.

Q1 REPORT 2013

SUMMARY

- Produced 51,957 boe/d (87% liquids) in Q1/2013, consistent with previous guidance. Current production is approximately 56,000 boe/d, and full-year production guidance is unchanged at 56,000 to 58,000 boe/d;
- Generated funds from operations (“FFO”) of $101.8 million ($0.83 per basic share) in Q1/2013;
- Six horizontal oil wells encompassing 66 laterals were drilled in the Peace River area which, subsequent to the end of the quarter, established average 30-day peak production rates of approximately 800 bbl/d, with our best performing well averaging over 1,000 bbl/d. These are amongst the highest rate wells we have drilled in the Peace River area, and compare favorably to the average 30-day peak production rates we achieved in 2011 and 2012 of approximately 500 bbl/d;
- Drilled 58 net wells in our Lloydminster heavy oil area with a 98% success rate, and one thermal infill well at our Kerrobert steam-assisted gravity drainage project;
- Continued to progress our Peace River thermal project, receiving regulatory approval for the second thermal module; and
- Completed the sale of non-core Viking rights in the Kerrobert area for net proceeds of $42 million.

	Three Months Ended		
	March 31, 2013	December 31, 2012	March 31, 2012
FINANCIAL			
(thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	272,945	292,095	343,355
Funds from operations(1)	101,772	127,253	141,736
Per share – basic	0.83	1.05	1.20
Per share – diluted	0.82	1.04	1.18
Cash dividends declared(2)	56,449	55,043	55,559
Cash dividends declared per share	0.66	0.66	0.66
Net income	10,149	31,620	42,958
Per share – basic	0.08	0.26	0.36
Per share – diluted	0.08	0.26	0.36
Exploration and development	166,522	66,686	135,918
Property acquisitions	–	130,575	2,336
Proceeds from divestitures	(42,382)	1,222	(3,568)
Total oil and natural gas capital expenditures	124,140	198,483	134,686
Bank loan	155,842	116,394	326,889
Long-term debt	452,340	449,235	299,865
Working capital deficiency	77,980	34,197	63,988
Total monetary debt(3)	686,162	599,826	690,742

	Three Months Ended		
	March 31, 2013	December 31, 2012	March 31, 2012
OPERATING			
Daily production			
Light oil and NGL (bbl/d)	**7,920**	7,739	7,565
Heavy oil (bbl/d)	**37,486**	40,257	38,353
Total oil and NGL (bbl/d)	**45,406**	47,996	45,918
Natural gas (mmcf/d)	**39.3**	42.3	45.1
Oil equivalent (boe/d @ 6:1)[4]	**51,957**	55,046	53,433
Average prices (before hedging)			
WTI oil (US$/bbl)	**94.37**	88.18	102.93
WCS heavy oil (US$/bbl)	**62.41**	70.07	81.51
Edmonton par oil ($/bbl)	**88.65**	84.28	92.81
Baytex light oil and NGL ($/bbl)	**76.72**	72.02	81.99
Baytex heavy oil ($/bbl)[5]	**53.47**	54.58	65.89
Baytex total oil and NGL ($/bbl)	**58.00**	57.39	68.54
Baytex natural gas ($/mcf)	**3.46**	3.03	2.46
Baytex oil equivalent ($/boe)	**52.89**	52.37	60.98
CAD/USD noon rate at period end	**1.0156**	0.9949	0.9991
CAD/USD average rate for period	**1.0089**	0.9913	1.0003
COMMON SHARE INFORMATION			
TSX			
Share price (Cdn$)			
High	**47.60**	48.35	59.40
Low	**42.00**	41.91	50.52
Close	**42.57**	42.87	51.79
Volume traded (thousands)	**27,768**	25,108	23,378
NYSE			
Share price (US$)			
High	**47.47**	49.25	59.50
Low	**41.04**	42.20	50.49
Close	**41.93**	43.24	51.86
Volume traded (thousands)	**3,369**	3,567	4,488
Common shares outstanding (thousands)	**122,874**	121,868	118,905

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 ended March 31, 2013.

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

(3) Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loan.

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

(5) Heavy oil prices are net of blending costs.

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to: our average production rate for 2013; our exploration and development capital expenditures for 2013; our production mix for 2013; development plans for our properties, including the number of wells to be drilled in the remainder of 2013 and, in some cases, when such wells will commence production; initial production rates from wells drilled; our Peace River heavy oil area, including our assessment of the productivity of recently drilled horizontal wells; our Cliffdale cyclic steam stimulation project, including our assessment of the steam and flowback operations and the cumulative steam-oil ratio for the initial 10-well module, our plan for a second module and the timing of drilling the wells for the second module; our plans for a steam-assisted gravity drainage pilot project at Angling Lake, including the timing of construction of the pilot facilities; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate light oil; the ability to access the U.S. Gulf Coast market by transporting crude oil on railways; 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 on railways in the second quarter of 2013; our production and operating expenses per unit of production for the balance of the 2013 year; our average royalty rate for full-year 2013; our debt-to-FFO ratio; the amount of our undrawn credit facilities at March 31, 2013; our liquidity and financial capacity; and our plan to amend our credit facilities to increase the amount and the term thereof and the timing of completing such amendments. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

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

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

MESSAGE TO SHAREHOLDERS

Operations Review

Production averaged 51,957 boe/d (87% oil and NGL) during Q1/2013, as compared to 53,433 boe/d (86% oil and NGL) in Q1/2012 and 55,046 boe/d (87% oil and NGL) in Q4/2012. First quarter production was impacted by the timing of Peace River area development drilling activities, the suspension of production at the Kerrobert steam-assisted gravity drainage ("SAGD") project to facilitate the drilling of an infill well, and the previously announced sale of non-core Viking rights in the Kerrobert area.

Our capital spending activity was weighted toward the latter portion of the first quarter with approximately half of the Q1/2013 capital expenditures incurred in March. Capital expenditures for exploration and development activities totaled $166.5 million for Q1/2013. During Q1/2013, Baytex participated in the drilling of 125 (110.0 net) wells with a 99% success rate.

Our 2013 production guidance remains at 56,000 to 58,000 boe/d with 2013 exploration and development capital expenditures forecast to be approximately $520 million. Current production is approximately 56,000 boe/d. Consistent with our budget expectations our production mix for 2013 is forecast to be 75% heavy oil, 14% light oil and NGL and 11% natural gas.

Wells Drilled – Three Months Ended March 31, 2013

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster area	67	57.7	1	1.0	–	–	–	–	1	1.0	69	59.7
Peace River area	6	6.0	–	–	–	–	30	30.0	–	–	36	36.0
	73	**63.7**	**1**	**1.0**	**–**	**–**	**30**	**30.0**	**1**	**1.0**	**105**	**95.7**
Light oil, NGL and natural gas												
Western Canada	12	10.3	–	–	1	1.0	–	–	–	–	13	11.3
North Dakota	7	3.0	–	–	–	–	–	–	–	–	7	3.0
	19	13.3	–	–	1	1.0	–	–	–	–	20	14.3
Total	**92**	**77.0**	**1**	**1.0**	**1**	**1.0**	**30**	**30.0**	**1**	**1.0**	**125**	**110.0**

Heavy Oil

In Q1/2013, heavy oil production averaged 37,486 bbl/d. During Q1/2013, we drilled 74 (64.7 net) oil wells, 30 (30.0 net) service and stratigraphic test wells, and one (1.0 net) dry and abandoned well on our heavy oil properties with a success rate of 99%.

Production from our Peace River area properties averaged approximately 18,900 bbl/d in Q1/2013. At Peace River, we drilled 26 (26.0 net) stratigraphic test wells, four (4.0 net) service wells, and six (6.0 net) horizontal oil wells (encompassing a total of 66 laterals) in Q1/2013. Subsequent to the end of the quarter, these six horizontal oil wells established average 30-day peak production rates of approximately 800 bbl/d, with our best performing well averaging over 1,000 bbl/d. These are amongst the highest rate wells we have drilled to date in the Peace River area, and compare favourably to the average 30-day peak production rates we achieved in 2011 and 2012 of approximately 500 bbl/d. Current production from our Peace River properties is approximately 22,000 bbl/d. We plan to drill approximately 31 multi-lateral horizontal wells in the remainder of 2013.

Successful operations continued at our Cliffdale 10-well cyclic steam stimulation ("CSS") module with Q1/2013 bitumen production averaging over 500 bbl/d. During Q1/2013, six wells received steam and commenced flowback operations. To-date, the Cliffdale project has demonstrated a cumulative steam-oil-ratio ("SOR") of 2.4. The initial Cliffdale pilot well recently completed fourth cycle production operations, producing 118% more oil than the previous cycle and achieving a cycle SOR of 2.1. Fifth cycle steaming operations on this well commenced on April 4th with flowback operations scheduled for late Q2/2013. Regulatory approval for our new Cliffdale 15-well CSS module was received in late March. Facility construction is underway and drilling operations are scheduled to commence mid-year 2013.

In our Lloydminster heavy oil area, Q1/2013 drilling included 32 (25.2 net) horizontal oil wells, 35 (32.5 net) vertical oil wells, and one (1.0 net) dry and abandoned well. We also drilled one (1.0 net) thermal infill well in the Kerrobert SAGD project which will commence production in Q2/2013. We plan to drill approximately 55 net wells in the Lloydminster area in the remainder of 2013.

At Angling Lake, preliminary work continued on the Gemini SAGD project, including installation of groundwater monitoring wells and facility engineering and design activities. We expect to commence construction of the Gemini SAGD pilot facilities in Q2/2013.

Light Oil & Natural Gas

During Q1/2013, light oil, NGL and natural gas production averaged 14,471 boe/d, which was comprised of 7,920 bbl/d of light oil and NGL and 39.3 mmcf/d of natural gas. This compared to Q1/2012 light oil and NGL production of 15,082 boe/d and Q4/2012 production of 14,789 boe/d.

In our Bakken/Three Forks play in North Dakota, we drilled seven (3.0 net) operated horizontal oil wells and fracture-stimulated five (1.5 net) operated wells in Q1/2013. During Q1/2013, two Baytex-operated wells on 1,280-acre spacing established average 30-day peak production rates of approximately 375 boe/d. We plan to drill approximately 13 (5.5 net) wells on our Bakken/Three Forks play in North Dakota in the remainder of 2013. We also drilled three (3.0 net) Bakken/Three Forks wells in south Saskatchewan in the first quarter, one of which received a multi-stage fracture treatment in the quarter.

In Q1/2013, we completed the previously disclosed disposition of approximately 22,000 net acres of non-core Viking rights in the Kerrobert area of southwest Saskatchewan, which included production of approximately 100 bbl/d, for net proceeds of $42 million.

Financial Review

We generated FFO of $101.8 million ($0.83 per basic share) in Q1/2013, compared to $141.7 million in Q1/2012 and $127.3 million in Q4/2012. The decrease relative to Q1/2012 was the result of lower realized commodity prices and lower sales volumes as well as higher operating expenses, while the decrease relative to Q4/2012 was largely the result of lower sales volumes and higher operating expenses.

The average WTI price for Q1/2013 was US$94.37/bbl, an 8% decrease from Q1/2012 and a 7% increase from Q4/2012. We received an average oil and NGL price of $58.00/bbl in Q1/2013 (inclusive of our physical hedging gains), a decrease of 15% from $68.54/bbl in Q1/2012 and an increase of 1% from $57.39/bbl in Q4/2012. Our realized oil prices include the impact of sales to new markets by rail, which averaged approximately 12,000 bbl/d of heavy oil for Q1/2013, as compared to 7,500 bbl/d for full-year 2012.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 34% in Q1/2013, as compared to 21% in both Q1/2012 and Q4/2012. Factors that caused heavy oil differentials to widen included apportionment on Canadian heavy oil export pipelines, reduced refinery runs due to normal seasonality and both planned and unplanned refinery maintenance.

Market conditions have improved recently with forward markets indicating a WCS average differential of approximately 20% for Q2/2013. Railways are continuing to play an expanding role in alleviating transportation constraints that limit the ability of Canadian crude supply to access new markets, including the U.S. Gulf Coast, which represents the largest North American heavy oil market.

In this volatile differential environment, Baytex continues to actively hedge its exposure to commodity prices and foreign exchange rates. For Q2/2013 to Q4/2013, we have entered into hedges on approximately 44% of our WTI exposure at a fixed price of US$98.10/bbl, 42% of our exposure to WCS heavy oil differentials through a combination of long term physical supply contracts and rail delivery, 45% of our natural gas price exposure, and

39% of our exposure to currency movements between the U.S. and Canadian dollars. Details of our hedging contracts are contained in the notes to our financial statements.

As part of our hedging program, we are focused on opportunities to further mitigate our exposure to WCS price differentials by transporting crude oil to higher value markets by railway. For Q2/2013, we expect to deliver approximately 16,000-17,000 bbl/d of our heavy oil volumes by rail, and we continue to explore opportunities for additional rail deliveries.

Production and operating expenses were $13.95/boe in the first quarter of 2013. These costs were higher than prior periods due to lower production volumes, higher than normal snow removal costs, increased labor costs, and higher energy input costs. We expect production and operating expenses to average approximately $12.00-$12.50/boe for the balance of 2013.

Royalty rates in Q1/2013 were approximately 18.3% of sales revenues before sales of purchased condensate. We expect royalty rates to average approximately 20-21% for full-year 2013 as a result of certain oil sands projects reaching payout and farm-in agreements.

Total monetary debt at the end of Q1/2013 was $686 million representing a debt-to-FFO ratio of 1.4 times based on FFO over the trailing twelve-month period. At the end of the quarter, Baytex had over $540 million in available undrawn credit facilities and no long term debt maturities until 2021. Proceeds from the sale of the Kerrobert Viking rights have been used to repay amounts outstanding on our credit facilities. Baytex is currently finalizing documentation with its lending syndicate to increase the amount of its credit facilities by $150 million to $850 million and to extend the maximum term of the facilities by one year to four years. We expect to have these facilities available by the end of the second quarter.

Conclusion

Baytex's operations continue to advance in accordance with our business plan. Our operational execution remains on target and we remain on track to meet our full-year production guidance. Our 2013 drilling program is well underway with very encouraging results, and we expect a continuing ramp up in our production in the coming quarters, which is likely to occur in a much stronger pricing environment for heavy oil. Our balance sheet remains in excellent shape with significant undrawn credit facilities. Utilizing our substantial 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
May 9, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2013. This information is provided as of May 8, 2013. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The first quarter results have been compared with the corresponding period in 2012. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three months ended March 31, 2013, its audited consolidated comparative financial statements for the years ended December 31, 2012 and 2011, together with accompanying notes, and its Annual Information Form for the year ended December 31, 2012. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts 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 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 March 31		
	2013	2012	Change
Daily Production			
Light oil and NGL (bbl/d)	7,920	7,565	5%
Heavy oil (bbl/d)(1)	37,486	38,353	(2%)
Natural gas (mmcf/d)	39.3	45.1	(13%)
Total production (boe/d)	51,957	53,433	(3%)
Production Mix			
Light oil and NGL	15%	14%	–
Heavy oil	72%	72%	–
Natural gas	13%	14%	–

(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 March 31, 2013, heavy oil sales volumes were 10 bbl/d lower than production volumes (three months ended March 31, 2012 – 91 bbl/d higher).

Production for the three months ended March 31, 2013 averaged 51,957 boe/d, compared to 53,433 boe/d for the same period in 2012. Light oil and natural gas liquids ("NGL") production in the first quarter of 2013 increased by 5% to 7,920 bbl/d, compared to 7,565 bbl/d in the first quarter of 2012 primarily due to successful development activities in the U.S. following the sale of 950 bbl/d associated with our non-operated position in North Dakota in the second quarter of 2012. Heavy oil production for the first quarter of 2013 decreased by 2% to 37,486 bbl/d from 38,353 bbl/d a year ago primarily due to the timing of our Peace River area development drilling program and the suspension of production at the Kerrobert Thermal project to facilitate the drilling of an infill well. Natural gas production decreased by 13% to 39.3 mmcf/d for the first quarter of 2013, as compared to 45.1 mmcf/d for the same period in 2012 primarily due to natural declines as we focused our capital spending on our oil projects.

Commodity Prices

Crude Oil

For the three months ended March 31, 2013, the WTI oil prompt price averaged US$94.37/bbl. WTI prompt prices rallied to start the year and peaked at US$97.97/bbl in late January on the back of stronger than expected demand, positive global economic growth sentiment and counter seasonal stock draws at Cushing, Oklahoma. WTI prices remained high until the start of March, at which time poor economic data out of the U.S., Europe and China, sent the WTI prompt price to a quarterly low of US$90.12/bbl. Prices were able to rally and recover some losses at the end of the quarter on a renewed bout of economic growth optimism.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 34% for the three months ended March 31, 2013, as compared to 21% for the three months ended March 31, 2012. On a fixed price basis, the WCS dollar differential during the first quarter widened to an average of US$31.96/bbl, as compared to US$18.11/bbl in the fourth quarter of 2012. Factors that caused heavy oil differentials to widen in late 2012 and continued to impact differentials in the first quarter of 2013 included apportionment on Canadian heavy oil export pipelines in both December and January, reduced refinery runs due to normal seasonality and both planned and unplanned refinery maintenance.

Natural Gas

For the three months ended March 31, 2013, the AECO natural gas price averaged $3.08/mcf, as compared to $2.52/mcf in the same period of 2012, and $3.06/mcf in the fourth quarter of 2012. Natural gas demand was weaker than expected in January 2013 due to mild weather, demand picked up in late February after colder temperatures arrived in most of the continent and the balance of the heating season experienced colder than normal conditions. This late seasonal demand minimized dependence on coal-to-gas switching while at the same time driving significantly larger than normal natural gas storage withdrawals.

	Three Months Ended March 31		
	2013	2012	Change
Benchmark Averages			
WTI oil (US$/bbl)[(1)]	$ 94.37	$ 102.93	(8%)
WCS heavy oil (US$/bbl)[(2)]	$ 62.41	$ 81.51	(23%)
Heavy oil differential[(3)]	(34%)	(21%)	
CAD/USD average exchange rate	1.0089	1.0002	1%
Edmonton par oil ($/bbl)	$ 88.65	$ 92.81	(4%)
AECO natural gas price ($/mcf)[(4)]	$ 3.08	$ 2.52	22%
Baytex Average Sales Prices			
Light oil and NGL ($/bbl)[(6)]	$ 76.72	$ 81.99	(6%)
Heavy oil ($/bbl)[(5)]	$ 50.77	$ 64.44	(21%)
Physical forward sales contracts gain ($/bbl)	2.70	1.45	
Heavy oil, net ($/bbl)	$ 53.47	$ 65.89	(19%)
Total oil and NGL, net ($/bbl)	$ 58.00	$ 68.54	(15%)
Natural gas ($/mcf)[(6)]	$ 3.46	$ 2.46	41%
Summary			
Weighted average ($/boe)[(6)]	$ 50.94	$ 59.77	(15%)
Physical forward sales contracts gain ($/boe)	1.95	1.21	
Weighted average, net ($/boe)	$ 52.89	$ 60.98	(13%)

(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 first quarter of 2013, Baytex's average sales price for light oil and NGL was $76.72/bbl, down 6% from $81.99/bbl in the first quarter of 2012. Baytex's realized heavy oil price during the first quarter of 2013, prior to physical forward sales contracts, was $50.77/bbl, or 81% of WCS. This compares to a realized heavy oil price in the first quarter of 2012, prior to physical forward sales contracts, of $64.44/bbl, or 79% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Other factors impacting Baytex's realized heavy oil price during this period were pipeline apportionments, periods of high WCS differential volatility, and quality discounts for some volumes. Net of physical forward sales contracts, Baytex's realized heavy oil price during the first quarter of 2013 was $53.47/bbl, down from $65.89/bbl in the first quarter of 2012. Baytex's realized natural gas price for the three months ended March 31, 2013 was $3.46/mcf, up from $2.46/mcf in the first quarter of 2012.

Gross Revenues

($ thousands except for %)	Three Months Ended March 31 2013	2012	Change
Oil revenue			
Light oil and NGL	$ 54,687	$ 56,443	(3%)
Heavy oil	180,360	230,506	(22%)
Total oil revenue	235,047	286,949	(18%)
Natural gas revenue	12,233	10,075	21%
Total oil and natural gas revenue	247,280	297,024	(17%)
Heavy oil blending revenue	25,665	46,331	(45%)
Total petroleum and natural gas revenues	$ 272,945	$ 343,355	(21%)

Petroleum and natural gas revenues decreased 21% to $272.9 million for the three months ended March 31, 2013 from $343.4 million for the same period in 2012. The reduction in revenues was driven by lower heavy oil revenues in the three months ended March 31, 2013 due to lower heavy oil volumes and prices than in first quarter of 2012. Heavy oil blending revenue for the three months ended March 31, 2013 was down 45% from the same period last year due to increase in volumes of heavy oil being transported by railway, which began in March 2012. Unlike transportation through oil pipelines, transportation of heavy oil by rail does not require condensate blending. In addition to lower sales of blended heavy oil, the decrease in revenue was also due to lower realized light oil, NGL and heavy oil prices, as well as lower heavy oil and natural gas sales volumes in the first quarter of 2013. Higher light oil, and NGL volumes and natural gas prices in the first quarter of 2013 partially offset the decrease in total revenues, as compared to 2012.

Royalties

($ thousands except for % and per boe)	Three Months Ended March 31 2013	2012	Change
Royalties	$ 45,278	$ 52,994	(15%)
Royalty rates:			
Light oil, NGL and natural gas	25.4%	18.5%	
Heavy oil	15.7%	17.7%	
Average royalty rates(1)	18.3%	17.8%	
Royalty expenses per boe	$ 9.68	$ 10.88	(11%)

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

Total royalties for the first quarter of 2013 decreased to $45.3 million from $53.0 million in the first quarter of 2012. Total royalties for the first quarter of 2013 were 18.3% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 17.8% for the same period in 2012.

Royalty rates for light oil, NGL and natural gas increased from 18.5% in the three months ended March 31, 2012 to 25.4% in the three months ended March 31, 2013 primarily due to higher royalties on U.S. properties resulting from a carry obligation partially offset by a higher number of wells qualifying under lower royalties and from lower realized pricing in the first quarter of 2013 in Canada, as compared to 2012. Royalty rates for heavy oil decreased from 17.7% in the three months ended March 31, 2012 to 15.7% in the three months ended March 31, 2013 due to lower realized pricing in the first quarter of 2013, as compared to 2012. Royalty rates in Q1/2013 were approximately 18.3% of sales revenues before sales of purchased condensate. We expect royalty rates to average approximately 20-21% for full-year 2013 as a result of certain oil sands projects reaching payout and farm-in agreements.

Financial Derivatives

($ thousands)	Three Months Ended March 31 2013	2012	Change
Realized gain (loss) on financial derivatives[1]			
Crude oil	$ 6,861	$ (8,553)	$ 15,414
Natural gas	343	1,225	(882)
Foreign currency	666	1,881	(1,215)
Interest rate	(3,742)	(1,693)	(2,049)
Total	$ 4,128	$ (7,140)	$ 11,268
Unrealized gain (loss) on financial derivatives[2]			
Crude oil	$ (10,300)	$ (8,918)	$ (1,382)
Natural gas	(2,387)	368	(2,755)
Foreign currency	(2,937)	3,312	(6,249)
Interest rate	3,729	1,036	2,693
Total	$ (11,895)	$ (4,202)	$ (7,693)
Total gain (loss) on financial derivatives			
Crude oil	$ (3,439)	$ (17,471)	$ 14,032
Natural gas	(2,044)	1,593	(3,637)
Foreign currency	(2,271)	5,193	(7,464)
Interest rate	(13)	(657)	644
Total	$ (7,767)	$ (11,342)	$ 3,575

(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 $4.1 million for the three months ended March 31, 2013 on derivative contracts relates to favorable contracts entered when crude oil prices were high, offset by losses on interest rate swaps as LIBOR rates remained low. The unrealized mark-to-market loss of $11.9 million for the three months ended March 31, 2013 relates to a weakening Canadian dollar against the U.S. dollar at March 31, 2013, as compared to December 31, 2012 and the reversal of previously recorded unrealized gains on crude oil contracts as they settled upon maturity. This was partially offset by settlement of previously recorded unrealized losses on interest rate contracts.

A summary of the risk management contracts in place as at March 31, 2013 and the accounting treatment of the Company's financial instruments are disclosed in note 16 to the condensed consolidated financial statements.

Production and Operating Expenses

($ thousands except for % and per boe)	Three Months Ended March 31 2013	2012	Change
Production and operating expenses	$ 65,216	$ 58,287	12%
Production and operating expenses per boe:			
Heavy oil	$ 13.94	$ 11.06	26%
Light oil, NGL and natural gas	$ 13.96	$ 14.28	(2%)
Total	$ 13.95	$ 11.97	17%

Production and operating expenses for the three months ended March 31, 2013 increased 12% to $65.2 million from $58.3 million. This increase is primarily due to harsh winter conditions in Saskatchewan and North Dakota, and increases in the costs of labour and energy inputs, which resulted in production and operating expenses of $13.95/boe for the three months ended March 31, 2013, as compared to $11.97/boe for the same period in 2012. The increase of 26% per boe for heavy oil was due to lower production volumes, harsh winter conditions in Saskatchewan, and increases in the costs of labour and energy inputs. We expect production and operating expenses to average approximately $12.00-$12.50/boe for the balance of the 2013 year.

Transportation and Blending Expenses

($ thousands except for % and per boe)	Three Months Ended March 31 2013	2012	Change
Blending expenses	$ 25,665	$ 46,331	(45%)
Transportation expenses	20,471	15,406	33%
Total transportation and blending expenses	$ 46,136	$ 61,737	(25%)
Transportation expenses per boe(1):			
Heavy oil	$ 5.83	$ 4.13	41%
Light oil, NGL and natural gas	$ 0.62	$ 0.70	(11%)
Total	$ 4.38	$ 3.16	39%

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

Transportation and blending expenses for the first quarter of 2013 were $46.1 million, as compared to $61.7 million for the first quarter of 2012.

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. The cost of blending diluent is effectively recovered in the sale price of the blended product. In the first quarter of 2013, blending expenses were $25.7 million for the purchase of 2,681 bbl/d of condensate at $106.37/bbl, as compared to $46.3 million for the purchase of 4,620 bbl/d at $110.19/bbl for the same period last year. This decrease in blending for the three months ended March 31, 2013 is due to significant volumes of heavy oil transported by rail beginning in March 2012, which does not require blending diluent.

Transportation expenses were $4.38/boe for the three months ended March 31, 2013, as compared to $3.16/boe for the same period of 2012. The increase in transportation expenses per barrel of heavy oil for the three months ended March 31, 2013 is primarily driven by increased use of long-haul trucking to deliver a larger percentage of our heavy oil production at Peace River to market.

Operating Netback

($ per boe except for % and volume)	Three Months Ended March 31 2013	2012	Change
Sales volume (boe/d)	51,947	53,524	(3%)
Operating netback(1):			
Sales price(2)	$ 52.89	$ 60.98	(13%)
Less:			
Royalties	9.68	10.88	(11%)
Operating expenses	13.95	11.97	17%
Transportation expenses	4.38	3.16	39%
Operating netback before financial derivatives	$ 24.88	$ 34.97	(29%)
Financial derivatives gain (loss)(3)	0.88	(1.47)	
Operating netback after financial derivatives gain (loss)	$ 25.76	$ 33.50	(23%)

(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 March 31, 2013 increased to $3.6 million from $2.5 million for the same period in 2012 due to impairment of evaluation and exploration assets that will not be developed, partially offset by a decrease in the expiration of undeveloped land leases.

Depletion and Depreciation

Depletion and depreciation for the three months ended March 31, 2013 increased to $78.6 million from $72.3 million for the same period in 2012. On a sales-unit basis, the provision for the current quarter was $16.81/boe, as compared to $14.85/boe for the same quarter in 2012. The increase is the result of increased production in areas with high depletable cost bases.

General and Administrative Expenses

	Three Months Ended March 31		
($ thousands except for % and per boe)	2013	2012	Change
General and administrative expenses	$ 11,550	$ 11,188	3%
General and administrative expenses per boe	$ 2.47	$ 2.30	7%

General and administrative expenses for the three months ended March 31, 2013 increased to $11.6 million from $11.2 million for the same period in 2012 due to higher salary, technical and professional service costs, partially offset by higher capital overhead recoveries. On a per boe basis, general and administrative expenses increased from $2.30 in the first quarter of 2012 to $2.47 in the first quarter of 2013 primarily due to lower production.

Share-based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan increased to $8.8 million for the three months ended March 31, 2013 (three months ended March 31, 2012 – $6.5 million) related to additional grants and the continued vesting of awards outstanding, offset by forfeitures of existing awards. Compensation expense related to the Share Rights Plan decreased to $0.3 million in the three months ended March 31, 2013 (three months ended March 31, 2012 – $0.4 million). Compensation expense attributable to the Share Rights Plan decreased as outstanding rights continue to be exercised while no new grants have been made under this plan since January 1, 2011.

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

Financing Costs

	Three Months Ended March 31		
($ thousands except for %)	2013	2012	Change
Bank loan and other	$ 1,615	$ 2,540	(36%)
Long-term debt	7,662	6,112	25%
Accretion on asset retirement obligations	1,660	1,627	2%
Debt financing costs	39	20	95%
Financing costs	$ 10,976	$ 10,299	7%

Financing costs for the three months ended March 31, 2013 increased to $11.0 million, as compared to $10.3 million in the first quarter of 2012. 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 the elimination of interest on the

$150 million principal amount of 9.15% Series A senior unsecured debentures that were redeemed on August 26, 2012 and lower bank borrowing.

Foreign Exchange

	Three Months Ended March 31		
($ thousands except for % and exchange rates)	**2013**	2012	Change
Unrealized foreign exchange loss (gain)	**$ 3,817**	$ (5,993)	(164%)
Realized foreign exchange (gain) loss	**(2,036)**	1,125	(281%)
Total loss (gain)	**$ 1,781**	$ (4,868)	(137%)
CAD/USD exchange rates:			
At beginning of period	**0.9949**	1.0170	
At end of period	**1.0156**	0.9991	

The unrealized loss of $3.8 million for the first quarter of 2013, as compared to a gain of $6.0 million for the first quarter of 2012, was mainly due to the changes in foreign currency translation on the US$150 million Series B senior unsecured debentures and the US$180 million portion of bank loan (bank loan outstanding as at March 31, 2012 and repaid July 2012) as the Canadian dollar weakened against the U.S. dollar at March 31, 2013 (as compared to December 31, 2012) and strengthened at March 31, 2012 (as compared to December 31, 2011). The current quarter realized gains were mainly due to day-to-day U.S. dollar denominated transactions from the strengthening U.S. dollar, as compared to the prior period realized losses on transactions due to a weakening U.S. dollar.

Income Taxes

For the three months ended March 31, 2013, deferred income tax expense was $3.8 million (three months ended March 31, 2012 – $17.8 million). When compared to the prior year, the decrease in deferred income tax expense is primarily the result of a decrease in the amount of tax pool claims required to shelter net income.

Net Income

Net income for the three months ended March 31, 2013 was $10.1 million, as compared to $43.0 million for the same period in 2012. The decrease in net income was due to a decrease in operating netbacks, and higher depletion and depreciation, offset by a gain on divestiture of oil and gas properties and lower deferred income tax expenses.

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 $8.6 million balance of accumulated other comprehensive loss at March 31, 2013 is the sum of a $12.5 million foreign currency translation loss incurred as at December 31, 2012 and a $3.9 million foreign currency translation gain related to the three months ended March 31, 2013.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

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

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

	Three Months Ended			Year Ended
($ thousands except for %)	March 31, 2013	December 31, 2012	March 31, 2012	December 31, 2012
Cash flow from operating activities	$ 95,174	$ 160,875	$ 151,361	$ 577,305
Change in non-cash working capital	12,782	(27,780)	(1,881)	(11,570)
Asset retirement expenditures	2,973	4,552	771	6,905
Financing costs	(10,976)	(12,236)	(10,299)	(47,191)
Accretion on asset retirement obligations	1,660	1,689	1,627	6,631
Accretion on debentures and long-term debt	159	153	157	645
Funds from operations	$ 101,772	$ 127,253	$ 141,736	$ 532,725
Cash dividends declared	$ 80,959	$ 80,215	$ 78,365	$ 317,110
Reinvested dividends	24,510	25,172	22,806	101,926
Cash dividends declared (net of DRIP)	$ 56,449	$ 55,043	$ 55,559	$ 215,184
Payout ratio	80%	63%	55%	60%
Payout ratio (net of DRIP)	55%	43%	39%	40%

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 $56.4 million for the first quarter of 2013 were funded by funds from operations of $101.8 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)	March 31, 2013	December 31, 2012
Bank loan	$ 155,842	$ 116,394
Long-term debt[(1)]	452,340	449,235
Working capital deficiency	77,980	34,197
Total monetary debt	$ 686,162	$ 599,826

(1) Principal amount of instruments.

At March 31, 2013 total monetary debt was $686.2 million, as compared to $599.8 million at December 31, 2012. Bank borrowings at March 31, 2013 were $155.8 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 prior to maturity. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain of our material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, our ability to pay dividends to shareholders may be restricted. A copy of the amended and restated credit agreement (and related amendments) which establishes the credit facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011, July 10, 2012 and January 14, 2013).

Baytex Energy is currently finalizing documentation with its lending syndicate to increase the amount of its credit facilities by $150 million to $850 million and to extend the maximum term of the facilities by one year to four years. Baytex Energy expects to have these facilities available by the end of the second quarter.

The weighted average interest rate on the bank loan for the three months ended March 31, 2013 was 5.68% (3.59% for the three months ended March 31, 2012).

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 March 31	
($ thousands)	2013	2012
Land	$ 2,985	$ 2,592
Seismic	558	848
Drilling and completion	118,745	95,335
Equipment	44,206	37,055
Other	28	88
Total exploration and development	$ 166,522	$ 135,918
Acquisitions – Properties	–	2,336
Proceeds from divestitures	(42,382)	(3,568)
Total acquisitions and divestitures	(42,382)	(1,232)
Total oil and natural gas expenditures	124,140	134,686
Other plant and equipment, net	3,370	5,044
Total capital expenditures	$ 127,510	$ 139,730

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 May 6, 2013 the Company had 123,172,484 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 March 31, 2013, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 226,977	$ 226,977	$ –	$ –	$ –
Dividends payable to shareholders	27,032	27,032	–	–	–
Bank loan(1)	155,842	–	155,842	–	–
Long-term debt(2)	452,340	–	–	–	452,340
Operating leases	44,606	6,111	12,844	12,392	13,259
Processing agreements	67,296	846	10,350	11,187	44,913
Transportation agreements	68,189	1,512	15,977	17,152	33,548
Total	$ 1,042,282	$ 262,478	$ 195,013	$ 40,731	$ 544,060

(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 March 31, 2013 and the accounting treatment of the Company's financial instruments are disclosed in note 16 to the condensed consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2013	2012				2011		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Gross revenues	**272,945**	292,095	299,786	284,248	343,355	367,813	313,787	336,899
Net income	**10,149**	31,620	26,773	157,280	42,958	57,780	51,839	106,863
Per common share – basic	**0.08**	0.26	0.22	1.32	0.36	0.49	0.45	0.92
Per common share – diluted	**0.08**	0.26	0.22	1.30	0.36	0.48	0.44	0.90

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; our average royalty rate for full-year 2013; our production and operating expenses per unit of production for the balance of the 2013 year; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; our plan to amend our credit facilities to increase the amount and the term thereof and the timing of completing such amendments; funding sources for our cash dividends and capital program; the timing of funding our financial obligations; and the existence, operation and strategy of our risk management program. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; third party credit risk; a downgrade of our credit ratings; risks associated with the exploitation of our properties and our ability to acquire reserves; increases in operating costs; changes in government regulations that affect the oil and gas industry; changes to royalty or mineral/severance tax regimes; risks relating to hydraulic fracturing; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties operated by third parties; risks associated with delays in business operations; risks associated with the marketing of our petroleum and natural gas production; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; expansion of our operations; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the activities of our operating entities and their key personnel and information systems; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonal weather patterns; our permitted investments; access to technological advances; changes in the demand for oil and natural gas products; involvement in legal, regulatory and tax proceedings; the failure of third parties to comply with confidentiality agreements; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2012, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	March 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash	$ 231	$ 1,837
Trade and other receivables	174,155	170,972
Crude oil inventory	1,643	1,363
Financial derivatives	8,727	20,167
	184,756	194,339
Non-current assets		
Exploration and evaluation assets (note 4)	229,602	240,015
Oil and gas properties (note 5)	2,123,149	2,037,576
Other plant and equipment	31,151	28,392
Goodwill	37,755	37,755
	$ 2,606,413	$ 2,538,077
LIABILITIES		
Current liabilities		
Trade and other payables	$ 226,977	$ 181,558
Dividends payable to shareholders	27,032	26,811
Financial derivatives	14,781	10,826
	268,790	219,195
Non-current liabilities		
Bank loan (note 6)	155,842	116,394
Long-term debt (note 7)	444,420	441,195
Asset retirement obligations (note 8)	270,222	265,520
Deferred income tax liability	193,944	189,160
Financial derivatives	4,451	7,201
	1,337,669	1,238,665
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 9)	1,904,887	1,860,358
Contributed surplus	57,342	65,615
Accumulated other comprehensive loss	(8,576)	(12,462)
Deficit	(684,909)	(614,099)
	1,268,744	1,299,412
	$ 2,606,413	$ 2,538,077

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Three Months Ended March 31	
(thousands of Canadian dollars, except per common share amounts) (unaudited)	2013	2012
Revenues, net of royalties (note 13)	$ 227,667	$ 290,361
Expenses		
Production and operating	65,216	58,287
Transportation and blending	46,136	61,737
Exploration and evaluation (note 4)	3,582	2,463
Depletion and depreciation	78,581	72,311
General and administrative	11,550	11,188
Share-based compensation (note 10)	9,044	6,856
Financing costs (note 14)	10,976	10,299
Loss on financial derivatives (note 16)	7,767	11,342
Foreign exchange loss (gain) (note 15)	1,781	(4,868)
Gain on divestiture of oil and gas properties	(20,951)	–
	213,682	229,615
Net income before income taxes	13,985	60,746
Income tax expense (note 12)		
Deferred income tax expense	3,836	17,788
Net income attributable to shareholders	$ 10,149	$ 42,958
Other comprehensive income (loss)		
Foreign currency translation adjustment	3,886	(5,386)
Comprehensive income	$ 14,035	$ 37,572
Net income per common share (note 11)		
Basic	$ 0.08	$ 0.36
Diluted	$ 0.08	$ 0.36
Weighted average common shares (note 11)		
Basic	122,491	118,563
Diluted	123,826	120,282

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) (unaudited)	Shareholders' capital	Contributed surplus[1]	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2011	$ 1,680,184	$ 85,716	$ (3,546)	$ (555,620)	**$ 1,206,734**
Dividends to shareholders	–	–	–	(78,365)	**(78,365)**
Exercise of share rights	21,246	(12,421)	–	–	**8,825**
Vesting of share awards	6,445	(6,445)	–	–	
Share-based compensation	–	6,856	–	–	**6,856**
Issued pursuant to dividend reinvestment plan	22,791	–	–	–	**22,791**
Comprehensive income for the period	–	–	(5,386)	42,958	**37,572**
Balance at March 31, 2012	**$ 1,730,666**	**$ 73,706**	**$ (8,932)**	**$ (591,027)**	**$ 1,204,413**
Balance at December 31, 2012	$ 1,860,358	$ 65,615	$ (12,462)	$ (614,099)	**$ 1,299,412**
Dividends to shareholders	–	–	–	(80,959)	**(80,959)**
Exercise of share rights	9,225	(5,507)	–	–	**3,718**
Vesting of share awards	11,810	(11,810)	–	–	**–**
Share-based compensation	–	9,044	–	–	**9,044**
Issued pursuant to dividend reinvestment plan	23,494	–	–	–	**23,494**
Comprehensive income for the period	–	–	3,886	10,149	**14,035**
Balance at March 31, 2013	**$ 1,904,887**	**$ 57,342**	**$ (8,576)**	**$ (684,909)**	**$ 1,268,744**

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

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of Canadian dollars) (unaudited)	Three Months Ended March 31 2013	2012
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income for the period	$ 10,149	$ 42,958
Adjustments for:		
Share-based compensation (note 10)	9,044	6,856
Unrealized foreign exchange loss (gain) (note 15)	3,817	(5,993)
Exploration and evaluation	3,582	1,830
Depletion and depreciation	78,581	72,311
Unrealized loss on financial derivatives (note 16)	11,895	4,202
Gain on divestitures of oil and gas properties	(20,951)	–
Deferred income tax expense	3,836	17,788
Financing costs (note 14)	10,976	10,299
Change in non-cash working capital	(12,782)	1,881
Asset retirement obligations settled (note 8)	(2,973)	(771)
	95,174	151,361
Financing activities		
Payments of dividends	(57,244)	(55,351)
Increase in bank loan	39,448	18,142
Issuance of common shares (note 9)	3,718	8,825
Interest paid	(16,538)	(14,55)
	(30,616)	(42,936)
Investing activities		
Additions to exploration and evaluation assets (note 4)	(4,150)	(3,731)
Additions to oil and gas properties (note 5)	(162,372)	(132,187)
Property acquisitions	–	(2,336)
Proceeds from divestitures of oil and gas properties	42,382	3,568
Additions to other plant and equipment, net of disposals	(3,370)	(5,044)
Change in non-cash working capital	61,831	26,118
	(65,679)	(113,612)
Impact of foreign currency translation on cash balances	(485)	152
Change in cash	(1,606)	(5,035)
Cash, beginning of period	1,837	7,847
Cash, end of period	$ 231	$ 2,812

See accompanying notes to the condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at March 31, 2013, December 31, 2012 *and for the three months ended March 31, 2013 and 2012*
(all tabular amounts in thousands of Canadian dollars, except per common share amounts) (unaudited)

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards ("IAS") 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2012. The Company's accounting policies are unchanged compared to December 31, 2012 except as listed in note 3 "Changes in Accounting Policies". The use of estimates and judgments is also consistent with the December 31, 2012 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on May 8, 2013.

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

3. CHANGES IN ACCOUNTING POLICIES

Certain standards and amendments were issued effective for accounting periods beginning on or after January 1, 2013. Many of these updates are not applicable or consequential to the Company and have been excluded from the discussion below. As of January 1, 2013, the Company adopted the following IFRS standards and amendments in accordance with the transitional provisions of each standard.

Consolidation, Joint Ventures and Disclosures

Consolidated Financial Statements

IFRS 10 "Consolidated Financial Statements" replaces the consolidation guidance in IAS 27 "Consolidation and Separate Financial Statements" and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities" by introducing a single consolidation model for all entities based on control, irrespective of the nature of the investee. Under IFRS 10, control is based on whether an investor has 1) power over the investee; 2) exposure, or rights, to variable returns from its involvement with the investee; and 3) the ability to use its power over the investee to affect the amount of the returns. The retrospective adoption of this standard does not have any impact on the Company's financial statements.

Joint Arrangement

IFRS 11 “Joint Arrangements” replaces the guidance on in IAS 31 “Interests in Joint Ventures” and SIC 13 “Jointly Controlled Entities – Non-Monetary Contributions by Ventures”, and divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. The retrospective adoption of this standard does not have any impact on the Company’s financial statements.

Disclosure of Interests in Other Entities

IFRS 12 “Disclosure of Interests in Other Entities” requires enhanced disclosures about both consolidated entities and unconsolidated entities in which an entity has involvement. The objective of IFRS 12 is to require information so that financial statement users may evaluate the basis of control, any restrictions on consolidated assets and liabilities, risk exposures arising from involvements with unconsolidated structured entities and non-controlling interest holders’ involvement in the activities of consolidated entities. The retrospective adoption of the annual disclosure requirements of this standard does not have a material impact on the Company’s financial statements.

Separate Financial Statements

IAS 27 “Separate Financial Statements” has been amended as a result of changes to IFRS 10. The retrospective adoption of these amendments does not have any impact on the Company’s financial statements.

Investments in Associates and Joint Ventures

IAS 28 “Investments in Associates and Joint Ventures” has been amended as a result of changes to IFRS 10 and IFRS 11. The retrospective adoption of these amendments does not have any impact on the Company’s financial statements.

Fair Value Measurement

IFRS 13 “Fair Value Measurement” defines fair value, establishes a framework for measuring fair value, and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard requires the revaluation of certain derivative financial liabilities on the Company’s consolidated balance sheets to reflect an appropriate amount of risk of non-performance by the Company. The prospective adoption of this standard does not have a material impact on the Company’s financial statements.

Financial Instruments: Disclosures

IFRS 7 “Financial Instruments: Disclosures” has been amended to provide disclosure requirements about rights of offset and related agreements for financial statements under an enforceable master netting or similar agreement. The retrospective adoption of these amendments does not have any impact on the Company’s financial statements.

4. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2011	**$ 129,774**
Capital expenditures	13,406
Property acquisitions	135,772
Exploration and evaluation expense	(12,202)
Transfer to oil and gas properties	(3,902)
Divestitures	(22,074)
Foreign currency translation	(759)
As at December 31, 2012	**$ 240,015**
Capital expenditures	4,150
Exploration and evaluation expense	(3,582)
Transfer to oil and gas properties	(11,233)
Divestitures	(571)
Foreign currency translation	823
As at March 31, 2013	**$ 229,602**

5. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2011	**$ 2,471,419**
Capital expenditures	405,219
Property acquisitions	8,270
Transferred from exploration and evaluation assets	3,902
Change in asset retirement obligations	5,429
Divestitures	(133,447)
Foreign currency translation	(2,483)
As at December 31, 2012	**$ 2,758,309**
Capital expenditures	162,372
Transferred from exploration and evaluation assets	11,233
Change in asset retirement obligations	5,979
Divestitures	(31,014)
Foreign currency translation	5,150
As at March 31, 2013	**$ 2,912,029**

Accumulated depletion	
As at December 31, 2011	**$ 439,259**
Depletion for the period	294,623
Divestitures	(13,089)
Foreign currency translation	(60)
As at December 31, 2012	**$ 720,733**
Depletion for the period	77,956
Divestitures	(10,154)
Foreign currency translation	345
As at March 31, 2013	**$ 788,880**

Carrying value	
As at December 31, 2012	**$ 2,037,576**
As at March 31, 2013	**$ 2,123,149**

6. BANK LOAN

As at	March 31, 2013	December 31, 2012
Bank loan	$ 155,842	$ 116,394

The Company's wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40.0 million extendible operating loan facility with a chartered bank and 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 prior to maturity. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain of its material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, Baytex's ability to pay dividends to its shareholders may be restricted.

The weighted average interest rate on the bank loan for the three months ended March 31, 2013 was 5.68% (3.59% for the three months ended March 31, 2012).

7. LONG-TERM DEBT

As at	March 31, 2013	December 31, 2012
6.75% Series B senior unsecured debentures (US$150,000 – principal) due February 17, 2021	150,416	147,305
6.625% Series C senior unsecured debentures (Cdn$300,000 – principal) due July 19, 2022	294,004	293,890
	$ 444,420	$ 441,195

Accretion expense on debentures of $0.2 million has been recorded in financing costs on long-term debt for the three months ended March 31, 2013 and 2012.

8. ASSET RETIREMENT OBLIGATIONS

	March 31, 2013	December 31, 2012
Balance, beginning of period	$ 265,520	$ 260,411
Liabilities incurred	4,225	7,092
Liabilities settled	(2,973)	(6,905)
Liabilities acquired	–	1,037
Liabilities divested	(1,294)	(2,372)
Accretion	1,660	6,631
Change in estimate(1)	3,048	(328)
Foreign currency translation	36	(46)
Balance, end of period	$ 270,222	$ 265,520

(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 March 31, 2013 is $322.5 million (December 31, 2012 – $318.7 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 March 31, 2013 is $270.2 million (December 31, 2012 – $265.5 million (discounted at 2.5%)).

9. 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 March 31, 2013, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2011	**117,893**	**$ 1,680,184**
Issued on exercise of share rights	1,366	21,873
Transfer from contributed surplus on exercise of share rights	–	36,667
Transfer from contributed surplus on vesting and conversion of share awards	403	20,118
Issued pursuant to dividend reinvestment plan	2,206	101,516
Balance, December 31, 2012	**121,868**	**$ 1,860,358**
Issued on exercise of share rights	228	3,718
Transfer from contributed surplus on exercise of share rights	–	5,507
Transfer from contributed surplus on vesting and conversion of share awards	241	11,810
Issued pursuant to dividend reinvestment plan	537	23,494
Balance, March 31, 2013	**122,874**	**$ 1,904,887**

Monthly dividends of $0.22 per common share were declared by the Company during the three months March 31, 2013 for total dividends declared of $81.0 million ($56.4 million net of dividend reinvestment program).

Subsequent to March 31, 2013, the Company announced that a monthly dividend in respect of April 2013 operations of $0.22 per common share totalling $27.1 million ($19.9 million net of dividend reinvestment program) will be paid on May 15, 2013 to shareholders of record on April 30, 2013.

10. EQUITY BASED PLANS

Share Award Incentive Plan

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

The Company recorded compensation expense related to the share awards of $8.8 million for the three months ended March 31, 2013 (three months ended March 31, 2012 – $6.5 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 $44.20 per restricted award and performance award granted during the three months ended March 31, 2013 (three months ended March 31, 2012 – $56.43 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Number of share awards *(000s)*
Balance, December 31, 2011	**365**	**229**	**594**
Granted	370	306	676
Vested and converted to common shares	(133)	(130)	(263)
Forfeited	(36)	(17)	(53)
Balance, December 31, 2012	**566**	**388**	**954**
Granted	188	152	340
Vested and converted to common shares	(99)	(62)	(161)
Forfeited	(26)	(5)	(31)
Balance, March 31, 2013	**629**	**473**	**1,102**

Share Rights Plan

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

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

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

Baytex recorded compensation expense related to the share rights under the Share Rights Plan of $0.3 million for the three months ended March 31, 2013 (three months ended March 31, 2012 – $0.4 million).

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

	Number of share rights *(000s)*	Weighted average exercise price
Balance, December 31, 2011[1]	**2,971**	**$ 16.98**
Exercised[2]	(1,366)	16.01
Forfeited[1]	(80)	21.27
Balance, December 31, 2012[1]	**1,525**	**$ 16.79**
Exercised[2]	(228)	16.25
Forfeited[1]	(1)	30.15
Balance, March 31, 2013[1]	**1,296**	**$ 16.23**

(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 March 31, 2013:

	Exercise Prices Applying Original Grant Price					Exercise Prices Applying Original Grant Price Reduced for Dividends and Distributions Subsequent to Grant Date				
PRICE RANGE	Number Outstanding at March 31, 2013 *(000s)*	Weighted Average Grant Price	Weighted Average Remaining Term *(years)*	Number Exercisable at March 31, 2013 *(000s)*	Weighted Average Exercise Price	Number Outstanding at March 31, 2013 *(000s)*	Weighted Average Exercise Price	Weighted Average Remaining Term *(years)*	Number Exercisable at March 31, 2013 *(000s)*	Weighted Average Exercise Price
$3.36 to $10.50	–	$ –	–	–	$ –	381	$ 7.88	0.6	381	$ 7.88
$10.51 to $18.00	405	17.89	0.6	405	17.89	172	15.10	1.0	172	15.10
$18.01 to $25.50	126	22.43	1.4	126	22.43	671	19.78	1.7	670	19.78
$25.51 to $33.00	726	27.84	1.6	719	27.80	63	29.04	2.1	45	28.53
$33.01 to $40.50	36	35.70	2.4	21	35.65	8	34.64	2.2	4	34.70
$40.51 to $47.72	3	45.02	2.7	2	45.06	1	41.97	2.8	1	41.97
$3.36 to $47.72	1,296	$ 24.45	1.3	1,273	$ 24.26	1,296	$ 16.23	1.3	1,273	$ 15.96

11. NET INCOME PER SHARE

Baytex calculates basic income per share based on the net income attributable to shareholders and a weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted and share rights were exercised. The treasury stock method is used to determine the dilutive effect of share awards and share rights whereby the estimated proceeds from the potential conversion of share awards and the exercise of share rights 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 March 31, 2013			Three Months Ended March 31, 2012		
	Net income	**Common Shares (000s)**	**Net income per share**	Net income	Common Shares (000s)	Net income per share
Net income – basic	**$ 10,149**	**122,491**	**$ 0.08**	$ 42,958	118,563	$ 0.36
Dilutive effect of share awards	**–**	**706**	**–**	–	205	–
Dilutive effect of share rights	**–**	**628**	**–**	–	1,514	–
Net income – diluted	**$ 10,149**	**123,826**	**$ 0.08**	$ 42,958	120,282	$ 0.36

12. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2013	2012
Net income before income taxes	$ 13,985	$ 60,746
Expected income taxes at the statutory rate of 25.51% (2012 – 25.45%)(1)	3,568	15,460
Increase (decrease) in income taxes resulting from:		
Share-based compensation	2,307	1,745
Effect of rate adjustments for foreign jurisdictions	(1,996)	(992)
Other	(43)	1,575
Income tax expense	$ 3,836	$ 17,788

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

13. REVENUES

	Three Months Ended March 31	
	2013	2012
Petroleum and natural gas revenues	$ 271,789	$ 341,155
Royalty charges	(45,278)	(52,994)
Royalty income	1,156	2,200
Revenues, net of royalties	$ 227,667	$ 290,361

14. FINANCING COSTS

	Three Months Ended March 31	
	2013	2012
Bank loan and other	$ 1,615	$ 2,540
Long-term debt	7,662	6,112
Accretion on asset retirement obligations	1,660	1,627
Debt financing costs	39	20
Financing costs	$ 10,976	$ 10,299

15. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended March 31	
	2013	2012
Unrealized foreign exchange loss (gain)	$ 3,817	$ (5,993)
Realized foreign exchange (gain) loss	(2,036)	1,125
Foreign exchange loss (gain)	$ 1,781	$ (4,868)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

At March 31, 2013, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	April to October 2013	US$1.00 million	1.0433	(1)
Monthly average collar	April to December 2013	US$1.00 million	1.0000 - 1.0725	(1)
Monthly average collar	April to December 2013	US$1.00 million	1.0100 - 1.0720	(1)
Monthly average collar	April to December 2013	US$1.00 million	1.0200 - 1.0575	(1)
Monthly average collar	April to December 2013	US$1.00 million	1.0200 - 1.0655	(1)
Monthly average collar	April to December 2013	US$1.00 million	1.0250 - 1.0702	(1)
Monthly average collar	April to December 2013	US$2.00 million	1.0300 - 1.0650	(1)
Monthly forward spot sale	April to December 2013	US$1.00 million	1.0320	(1)(3)
Monthly forward spot sale	April to December 2013	US$2.00 million	1.0336	(1)(3)
Monthly forward spot sale	April to December 2013	US$2.00 million	1.0346	(1)(3)
Monthly forward spot sale	April to December 2013	US$2.00 million	1.0450	(1)(3)
Monthly forward spot sale	April to December 2013	US$2.00 million	1.0500	(1)(3)
Monthly forward spot sale	April to December 2013	US$1.00 million	1.0530	(1)(3)
Monthly forward spot sale	April to December 2013	US$1.00 million	1.0547	(1)(3)
Monthly average rate forward	April to December 2013	US$1.00 million	1.0360	(1)
Monthly average rate forward	April to December 2013	US$1.00 million	1.0300	(1)
Monthly forward spot sale	April to December 2013	US$4.50 million	1.0014	(2)
Monthly forward spot sale	April to December 2013	US$1.00 million	1.0300	(1)(3)
Monthly average rate forward	April to December 2013	US$1.00 million	1.0274	(1)(3)
Monthly average rate forward	April to December 2013	US$0.25 million	1.0023	(1)
Monthly average collar	April to December 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).

(3) Counterparty has the option to extend the term by twelve months.

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

	Assets		Liabilities	
	March 31, 2013	December 31, 2012	**March 31, 2013**	December 31, 2012
U.S. dollar denominated	**US$66,204**	US$124,048	**US$216,371**	US$201,980

Interest Rate Risk

As at March 31, 2013, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay fixed, receive floating	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 March 31, 2013, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit[1]	Index
Fixed – Buy	April to June 2013	250 bbl/d	US$102.07	WTI
Fixed – Sell	April to June 2013[2]	2,000 bbl/d	US$98.05	WTI
Fixed – Sell	April to June 2013[2]	1,000 bbl/d	US$102.05	WTI
Fixed – Sell	April to June 2013[2]	1,000 bbl/d	US$104.10	WTI
Fixed – Sell	April to June 2013[2]	2,000 bbl/d	US$103.80	WTI
Fixed – Sell	April to September 2013[2]	2,000 bbl/d	US$101.60	WTI
Fixed – Sell	April to December 2013	12,000 bbl/d	US$96.58	WTI
Fixed – Sell	June to December 2013[2]	1,000 bbl/d	US$99.50	WTI
Fixed – Buy	July to December 2013	350 bbl/d	US$101.70	WTI
Fixed – Sell	July to December 2013[2]	1,000 bbl/d	US$99.00	WTI
Fixed – Sell	July to December 2013[3]	1,000 bbl/d	US$96.25	WTI
Fixed – Sell	July to December 2013[2]	1,000 bbl/d	US$104.70	WTI
Fixed – Buy	January to December 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 extend the term by six months.

(3) Counterparty has the option to double the volumes on the contract.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	April to December 2013	2,000 GJ/d	$3.37	AECO
Fixed – Sell	April to December 2013	2,000 mmBtu/d	US$4.02	NYMEX
Fixed – Sell	April to December 2013	1,000 mmBtu/d	US$4.05	NYMEX
Fixed – Sell	April to December 2013	1,000 mmBtu/d	US$4.07	NYMEX
Fixed – Sell	April to December 2013	1,000 mmBtu/d	US$4.10	NYMEX
Basis swap	April to December 2013	2,000 mmBtu/d	NYMEX less US$0.375	AECO
Basis swap	April to December 2013	1,000 mmBtu/d	NYMEX less US$0.388	AECO
Basis swap	April to December 2013	2,000 mmBtu/d	NYMEX less US$0.428	AECO
Price collar	April to December 2013	10,000 mmBtu/d	US$3.50 – US$3.75	NYMEX
Price collar	November 2013 to March 2014	10,000 mmBtu/d	US$4.00 – US$4.50	NYMEX
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.

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 March 31	
	2013	2012
Realized (gain) loss on financial derivatives	$ (4,128)	$ 7,140
Unrealized loss on financial derivatives	11,895	4,202
Loss on financial derivatives	$ 7,767	$ 11,342

Subsequent to March 31, 2013, Baytex added the following financial derivative contracts:

Natural Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	May to October 2013	2,500 mmBtu/d	US$4.16	NYMEX
Price collar	November 2013 to March 2014	2,500 mmBtu/d	US$4.20 – US$4.60	NYMEX

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

Physical Delivery Contracts

At March 31, 2013, 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	April 2013 to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	April to June 2013	1,250 bbl/d	WTI × 80.00%
WCS Blend	April to June 2013	4,250 bbl/d	WTI less US$18.18
WCS Blend	May to December 2013	2,000 bbl/d	WTI less US$21.50
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 to December 2013	160 bbl/d	WTI plus US$3.10

At March 31, 2013, Baytex had committed to deliver the volumes of raw bitumen noted below to market on railways:

Heavy Oil	Period	Term Volume
Raw bitumen	April to June 2013	11,800 bbl/d
Raw bitumen	July to September 2013	5,225 bbl/d
Raw bitumen	October to December 2013	5,225 bbl/d
Raw bitumen	January to March 2014	4,000 bbl/d
Raw bitumen	April to June 2014	3,675 bbl/d

17. 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 March 31, 2013, and December 31, 2012 and for the three months ended March 31, 2013 and 2012 for: 1) Baytex, on a stand-alone basis, 2) Guarantor subsidiaries, on a stand-alone basis, 3) non-guarantor subsidiaries, on a stand-alone basis and 4) Baytex, on a consolidated basis.

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
As at March 31, 2013					
Current assets	$ –	$ 184,534	$ 222	$ –	$ 184,756
Intercompany advances and investments	1,711,117	(559,70)	76,531	(1,227,941)	–
Non-current assets	2,432	2,419,225	–	–	2,421,657
Current liabilities	32,230	236,356	204	–	268,790
Bank loan and long-term debt	444,420	155,842	–	–	600,262
Asset retirement obligation and other non-current liabilities	$ –	$ 468,617	$ –	$ –	$ 468,617
As at December 31, 2012					
Current assets	$ 4	$ 194,086	$ 249	$ –	$ 194,339
Intercompany advances and investments	1,756,923	(555,059)	70,298	(1,272,162)	–
Non-current assets	2,435	2,341,303	–	–	2,343,738
Current liabilities	39,478	179,503	214	–	219,195
Bank loan and long-term debt	441,195	116,394	–	–	557,589
Asset retirement obligation and other non-current liabilities	$ –	$ 461,881	$ –	$ –	$ 461,881
For the three months ended March 31, 2013					
Revenues, net of royalties	$ 5,752	$ 228,012	$ 6,233	$ (12,330)	$ 227,667
Production, operation and exploration	–	68,798	–	–	68,798
Transportation and blending	–	46,136	–	–	46,136
General, administrative and unit-based compensation	345	20,572	22	(345)	20,594
Financing, derivatives, foreign exchange and other (gains)/losses	10,766	797	(5)	(11,985)	(427)
Depletion and depreciation	–	78,581	–	–	78,581
Income tax expense	–	3,836	–	–	3,836
Net income (loss)	$ (5,359)	$ 9,292	$ 6,216	$ –	$ 10,149
For the three months ended March 31, 2012					
Revenues, net of royalties	$ 5,833	$ 290,736	$ 3,906	$ (10,114)	$ 290,361
Production, operation and exploration	–	60,750	–	–	60,750
Transportation and blending	–	61,737	–	–	61,737
General, administrative and share-based compensation	375	17,946	98	(375)	18,044
Financing, derivatives, foreign exchange and other (gains)/losses	3,378	23,131	3	(9,739)	16,773
Depletion and depreciation	–	72,311	–	–	72,311
Income tax expense	–	17,788	–	–	17,788
Net income	$ 2,080	$ 37,073	$ 3,805	$ –	$ 42,958

(thousands of Canadian dollars)		Baytex		Guarantor Subsidiaries		Non-guarantor Subsidiaries		Consolidation Adjustments		Total Consolidated
For the three months ended March 31, 2013										
Cash provided by (used in):										
Operating activities	$	5,547	$	89,876	$	(249)	$	–	$	95,174
Payment of dividends		(57,244)		–		–		–		(57,244)
Decrease in bank loan		–		39,448		–		–		39,448
Change in intercompany loans		63,123		(63,123)		–		–		–
Increase in equity		3,718		–		–		–		3,718
Interest paid		(15,144)		(1,394)		–		–		(16,538)
Financing activities		(5,547)		(25,069)		–		–		(30,616)
Additions to exploration and evaluation assets		–		(4,150)		–		–		(4,150)
Additions to oil and gas properties		–		(162,372)		–		–		(162,372)
Proceeds from divestitures		–		42,382		–		–		42,382
Additions to other plant and equipment, net of disposals		–		(3,370)		–		–		(3,370)
Change in non-cash working capital		–		61,831		–		–		61,831
Investing activities		–		(65,679)		–		–		(65,679)
Impact of foreign currency translation on cash balances	$	–	$	(485)	$	–	$	–	$	(485)
For the three months ended March 31, 2012										
Cash provided by (used in):										
Operating activities	$	72,244	$	79,117	$	–	$	–	$	151,361
Payment of dividends		(55,351)		–		–		–		(55,351)
Increase in bank loan		–		18,142		–		–		18,142
Increase (decrease) in intercompany loans		(13,860)		27,884		(14,024)		–		–
Increase in investments		–		(14,024)		–		14,024		–
Increase in equity		8,825		–		14,024		(14,024)		8,825
Interest paid		(11,858)		(2,694)		–		–		(14,552)
Financing activities		(72,244)		29,308		–		–		(42,936)
Additions to exploration and evaluation assets		–		(3,731)		–		–		(3,731)
Additions to oil and gas properties		–		(132,187)		–		–		(132,187)
Property acquisitions		–		(2,336)		–		–		(2,336)
Proceeds from divestitures		–		3,568		–		–		3,568
Additions to other plant and equipment, net of disposals		–		(5,044)		–		–		(5,044)
Change in non-cash working capital		–		26,118		–		–		26,118
Investing activities		–		(113,612)		–		–		(113,612)
Impact of foreign currency translation on cash balances	$	–	$	152	$	–	$	–	$	152

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

Raymond T. Chan
Executive Chairman
Baytex Energy Corp.

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

John A. Brussa(2)(3)(4)
Vice Chairman
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

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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
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

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