HIGHLIGHTS

- Produced a quarterly record of 46,902 boe/d in Q1/2011 (an increase of 4% over Q4/2010);
- Generated funds from operations ("FFO") in the first quarter of $110 million ($0.96 per basic share), despite $2 million of debt origination and transaction expenses and $13 million of reduced revenues due to heavy oil market disruptions. Excluding these items, FFO would have been $1.09 per basic share;
- Advanced our thermal production project at Seal with a third successful injection cycle on our pilot well, with higher injectivity and a projected steam-oil-ratio of 1.9 based on initial production results;
- Completed the acquisition of heavy oil assets in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan for total consideration of $155 million at accretive metrics, as previously disclosed;
- Issued US$150 million in 10 year senior unsecured debentures at par, with a coupon of 6.75%. Upon receipt of the proceeds from this issue, reduced Canadian currency drawings on our credit facilities;
- Increased the amount of our credit facilities to $650 million (from $550 million), of which $350 million remains undrawn at the end of Q1/2011;
- Updated the contingent resource assessment on three of our oil resource plays to May 1, 2011 and completed an economic assessment of our contingent resource. The net present value attributable to the "best estimate" (C2) of contingent resource (before tax, discounted at 10%) was estimated at $4.4 billion;
- Maintained a cash payout ratio in Q1/2011 of 48% net of dividend reinvestment plan ("DRIP") participation; and
- Delivered total market return (assuming reinvestment of dividends) of 23% in Q1/2011.

	Three Months Ended		
	March 31, 2011	December 31, 2010	March 31, 2010
FINANCIAL *(thousands of Canadian dollars, except per common share or unit amounts)*			
Petroleum and natural gas sales	**290,315**	263,497	261,782
Funds from operations[1]	**109,470**	123,161	106,207
Per share or unit – basic	**0.96**	1.09	0.96
Per share or unit – diluted	**0.93**	1.06	0.95
Cash dividends or distributions declared[2]	**52,002**	48,126	49,142
Per share or unit	**0.60**	0.56	0.54
Net income	**950**	21,356	29,815
Per share or unit – basic	**0.01**	0.19	0.27
Per share or unit – diluted	**0.01**	0.18	0.27
Exploration and development	**87,014**	59,350	55,356
Property acquisitions	**37,518**	3,096	2,333
Divestitures	**–**	(896)	–
Corporate acquisition	**117,346**	–	–
Total oil and gas expenditures	**241,878**	61,550	57,689
Bank loan	**298,591**	303,773	257,364
Convertible debentures	**–**	–	6,353
Long-term debt	**295,770**	150,000	150,000
Working capital deficiency	**73,709**	52,462	56,404
Total monetary debt[3]	**668,070**	506,235	470,123

	Three Months Ended		
	March 31, 2011	December 31, 2010	March 31, 2010
OPERATING			
Daily production			
Light oil and NGL (bbl/d)	6,606	6,457	6,660
Heavy oil (bbl/d)	31,792	29,808	27,278
Total oil (bbl/d)	38,398	36,265	33,938
Natural gas (mmcf/d)	51.0	52.5	56.9
Oil equivalent (boe/d @ 6:1)(4)	46,902	45,015	43,425
Average prices (before hedging)			
WTI oil (US$/bbl)	94.10	85.17	78.71
Edmonton par oil ($/bbl)	88.45	80.73	80.31
BTE light oil and NGL ($/bbl)	75.68	68.07	68.04
BTE heavy oil ($/bbl)(5)	59.89	60.10	62.07
BTE total oil and NGL ($/bbl)	62.57	61.53	63.24
BTE natural gas ($/mcf)	4.19	3.84	5.31
BTE oil equivalent ($/boe)	55.86	53.99	56.41
USD/CAD noon rate at period end	1.0290	1.0054	0.9846
USD/CAD average rate for period	1.0142	0.9873	0.9607
COMMON SHARE OR TRUST UNIT INFORMATION			
TSX			
Share or Unit price (Cdn$)			
High	$ 56.95	$ 48.15	$ 36.80
Low	$ 46.00	$ 37.12	$ 29.50
Close	$ 56.69	$ 46.61	$ 34.35
Volume traded (thousands)	34,198	32,579	22,448
NYSE			
Share or Unit price (US$)			
High	$ 58.52	$ 47.82	$ 36.07
Low	$ 46.25	$ 35.96	$ 27.56
Close	$ 58.38	$ 46.82	$ 33.96
Volume traded (thousands)	8,184	5,231	4,452
Common shares or trust units outstanding (thousands)	115,177	113,712	110,650

(1) Funds from operations is a non-GAAP measure that represents cash generated from operating activities less finance costs before changes in non-cash 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, 2011.

(2) Cash dividends or distributions declared are net of DRIP.

(3) Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred income tax assets or liabilities and unrealized gain or loss on financial derivatives, the statement of financial position value of the bank loan, the debt portion of convertible debentures and the principal amount of long-term debt.

(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 wellhead prices are net of blending costs.

Forward-Looking Statements

This report contains forward-looking statements relating to: our exploration and development capital expenditures for 2011; our average production rate for 2011; the growth profile of our 2011 production; our product mix for 2011; initial production rates from wells drilled; development plans for our properties, including the number of wells to be drilled in 2011; our heavy oil resource play at Seal, including our assessment of the results of the third steam injection cycle for our pilot well, including the steam-oil ratio, and the completion of a 10-well module of cyclic steam stimulation development; production from the heavy oil assets acquired on February 3, 2011 for the last nine months of 2011; our light oil resource play in North Dakota, including the timing of completing multi-stage fracture treatments on wells previously drilled; our ability to fund our capital expenditures and dividends from funds from operations in 2011; the existence, operation and strategy of our risk management program for commodity prices and foreign exchange rates; the amount of our undrawn credit facilities at March 31, 2011; our debt to fund from operations ratio; our liquidity and financial capacity; and the sufficiency of our financial resources to finance our operations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. The level of future cash dividends will depend on the amount of funds from operations generated by our operations and our prevailing financial circumstances at the time. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking statements.

Contingent Resource

This report contains estimates as of May 1, 2011 of the volumes of, and the net present value of the future net revenue from, the "contingent resource" for three of our oil resource plays. "Contingent resource" is not, and should not be confused with, petroleum and natural gas reserves. "Contingent resource" is defined in the Canadian Oil and Gas Evaluation Handbook as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage." A "best estimate" of contingent resource means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

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

The primary contingencies which currently prevent the classification of the contingent resource as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; demonstration of economic viability; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The estimates of contingent resource involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future. The net present value of the future net revenue from the contingent resource does not necessarily represent the fair market value of the contingent resource.

Notice to United States Readers: The United States Securities and Exchange Commission does not permit the inclusion of estimates of resources in reports filed with it by United States companies.

Non-GAAP Financial Measures

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

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

MESSAGE TO SHAREHOLDERS

Operations Review

Production averaged 46,902 boe/d during the first quarter of 2011, as compared to 43,425 boe/d in the first quarter of 2010 and 45,015 boe/d in the fourth quarter of 2010. Oil-equivalent production increased by 8% from the first quarter of 2010, with oil production 13% higher and natural gas production 10% lower than in the prior year comparative period. Oil equivalent production increased by 4% from the fourth quarter of 2010, with oil production 6% higher and natural gas production 3% lower than in the prior quarter.

Capital expenditures for exploration and development activities totaled $87.0 million for the first quarter of 2011. During the first quarter, Baytex participated in the drilling of 71 (57.8 net) wells, resulting in 60 (46.8 net) oil wells, one (1.0 net) natural gas well, six (6.0 net) stratigraphic test wells, three (3.0 net) thermal observation wells and one (1.0 net) dry and abandoned well for a 99% (98% net) success rate. In our Lloydminster heavy oil area, we drilled 31 (28.8 net) oil wells and two (2.0 net) thermal observation wells. At Seal, we drilled five (5.0 net) horizontal cold production wells, four (4.0 net) horizontal cyclic steam stimulation ("CSS") wells, six (6.0 net) stratigraphic test wells and one (1.0 net) thermal observation well. In our light oil and gas areas in western Canada, we drilled eight (5.4 net) oil wells, one (1.0 net) natural gas well and one (1.0 net) dry and abandoned well. In North Dakota, we drilled 12 (3.6 net) oil wells.

Consistent with previous guidance, our exploration and development capital budget for 2011 is $325 million, which, together with the heavy oil acquisition completed in February, is designed to generate an average production rate of 49,000 to 50,000 boe/d for 2011. We expect quarter-to-quarter production growth throughout 2011. Due to better than anticipated heavy oil drilling results and gas plant restrictions on certain gas properties that affect both natural gas and natural gas liquids ("NGL") production, we now project that our production mix will be comprised of 69% heavy oil, 15% light oil and NGL and 16% natural gas. To date, our production levels have not been affected by the Rainbow or Keystone pipeline interruptions.

Heavy Oil

In the first quarter of 2011, heavy oil production averaged 31,792 bbl/d, an increase of 17% over the first quarter of 2010 and 7% over the fourth quarter of 2010. During the first quarter of 2011, we drilled 40 (37.8 net) producing wells, six (6.0 net) stratigraphic test wells and three (3.0 net) thermal observation wells on our heavy oil properties for a success rate of 100%.

Production from our Seal properties (excluding production from the properties acquired in the first quarter) averaged 10,445 bbl/d in the first quarter, an increase of 3% from the fourth quarter of 2010 and 44% from the first quarter of 2010. In the first quarter of 2011, Seal drilling included six (6.0 net) stratigraphic test wells and five (5.0 net) cold horizontal producers, with 11 to 15 laterals per well. Two of the new wells have established average 30-day peak production rates of approximately 630 bbl/d per well. The remaining three cold horizontal drills were put on production subsequent to the end of the first quarter, and have not recorded full 30-day production rates, but are among the highest production rate wells that we have drilled at Seal. For the remainder of 2011, we plan to drill at least 15 additional multi-lateral cold horizontal wells at Seal. A third rig was added to the Seal horizontal drilling operations after the end of the first quarter, up from an average rig count of two during the first quarter.

In our Cliffdale CSS project at Seal, we completed our third steam injection cycle in our pilot well, and placed the well back on production at the end of the first quarter. Injectivity continued to improve in this third cycle, with the injected steam slug size being 72% greater than in the second cycle and 110% greater than in the first cycle. Subsequent to the first quarter of 2011, the pilot well reached peak oil rates of approximately 435 bbl/d, with cumulative oil production through the first month approximately 20% higher than in the second cycle. Based on the results to date, we project a steam-oil-ratio of 1.9 for the third cycle, approximately the same as in the second cycle. In the first quarter of 2011, we drilled one (1.0 net) thermal observation well and four (4.0 net) horizontal CSS wells at Cliffdale. The new horizontal CSS wells were placed on cold production at rates of approximately 25 bbl/d per well, and are scheduled for steam injection upon completion of our steam facility expansion. To complete our first 10-well commercial module, we plan to drill an additional five horizontal CSS wells in 2011 once our final drilling permits are received.

On February 3, 2011, we closed the acquisition of heavy oil assets located in the Seal and Lloydminster areas. The assets were acquired through a combination of a corporate acquisition of a private company and an asset acquisition from another private company for aggregate cash consideration of $155 million. The acquisition contributed approximately 1,400 bbl/d to first quarter production and is expected to contribute approximately 2,600 bbl/d (100% heavy oil) for the remainder of 2011. The acquisition included approximately 158 sections of oil sands leases at Seal.

Light Oil & Natural Gas

During the first quarter of 2011, light oil and natural gas production averaged 15,110 boe/d, which was comprised of 6,606 bbl/d of light oil and NGL and 51.0 mmcf/d of natural gas. Compared to the first quarter of 2010, light oil and NGL production declined by 0.8% and natural gas production declined by 10.4%. Compared to the fourth quarter of 2010, light oil and NGL production increased by 2% and natural gas production declined by 3%. In the case of light oil and NGL production, declines in conventional fields and in NGL from natural gas production were offset by increasing production from light oil resource plays. In the first quarter of 2011, we drilled 20 (9.0 net) oil wells, one (1.0 net) natural gas well and one (1.0 net) dry and abandoned well for a 95% (91% net) success rate.

We continued development activities to advance our light oil resource plays. In our Cardium play in Alberta, we drilled and completed three (3.0 net) horizontal Cardium wells in the first quarter. Two of the wells were placed on production and established 30-day average peak rates of approximately 230 boe/d per well. We plan to drill approximately five additional Cardium horizontal wells in 2011.

In the first quarter of 2011, we drilled and completed one (1.0 net) unstimulated Viking multi-lateral well in Alberta, but it has not been on production long enough to establish a 30-day average peak rate. We plan to drill approximately 15 additional Viking light oil horizontal wells in 2011, the majority of which will be unstimulated multi-lateral wells in Alberta.

In our Bakken/Three Forks play in North Dakota, we participated in the drilling of twelve (3.6 net) horizontal oil wells in the first quarter, five of which were Baytex-operated. At the end of the first quarter of 2011, eleven (4.1 net) wells were waiting for multi-stage fracture treatments. We have fracture treatment dates scheduled in the second quarter for at least seven of these wells. A 1280-acre spacing well that was drilled in the fourth quarter of 2010 established a 30-day average peak rate in the first quarter in 2011 of 775 bbl/d (290 bbl/d net). To date, Baytex-interest wells on 640-acre spacing have established 30-day average peak rates of 260 bbl/d and Baytex-interest wells on 1280-acre spacing have established 30-day average peak rates of 435 bbl/d.

Financial Review

The financial statements for the first quarter of 2011 are Baytex's first financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). Comparative periods in 2010 have been restated to conform to IFRS presentation. Reconciliations from IFRS to the previously reported financial results are shown in the notes to our financial statements. The adoption of IFRS did not have a material impact on the amounts reported as FFO.

We generated FFO of $110 million ($0.96 per basic share) in the first quarter of 2011, an increase of 3% compared to the first quarter of 2010, and a decrease of 11% compared to the fourth quarter of 2010. The decrease in FFO relative to the fourth quarter of 2010 primarily related to lower realized hedging gains in the first quarter as several favorable hedging contracts, primarily for forward US currency sales, matured at the end of 2010. Also, in the first quarter we incurred approximately $2 million in non-recurring expenses related to amendments to our credit facilities and fees for advisory services on the acquisition completed in the first quarter.

The average WTI price for the first quarter of 2011 was US$94.10/bbl, a 20% increase from the first quarter of 2010, and a 10% increase from the fourth quarter 2010. We received an average oil price of $62.57/bbl in the first quarter of 2011 (inclusive of our physical hedging gains), down from $63.24/bbl for the first quarter of 2010 and up from

$61.53/bbl for the fourth quarter of 2010. We also received an average natural gas price of $4.19/mcf in the first quarter of 2011, a decrease of 21% from the first quarter of 2010 and an increase of 9% from the prior quarter. The discount for heavy oil, as measured by the Western Canadian Select price differential to WTI, averaged 24.3% for the first quarter of 2011, as compared to 12.0% in the first quarter of 2010 and 21.5% in the fourth quarter of 2010.

Although our average realized heavy oil price including financial hedges for the first quarter of $59.89/bbl was modestly lower than the $60.10/bbl we realized in the fourth quarter of 2010, our first quarter 2011 heavy oil revenues were lower than expected for two reasons. First, the spot market for heavy oil was negatively impacted by high inventories resulting from the Enbridge pipeline leaks in the fall of 2010. These inventories persisted for longer than expected because of downtime for pipeline repairs conducted by Enbridge in the first quarter of 2011. Due to our concerns about potential pipeline apportionment, we sold some volumes at daily spot market prices and into lower value delivery points such that our price realizations were less than monthly index pricing. Second, we incurred higher condensate blending costs due to colder than normal weather and lower condensate quality in the first quarter. We estimate that these marketing factors resulted in first quarter revenues (net of royalties) being approximately $13 million lower than if we had sold all of our heavy oil at monthly index prices and with customary condensate conditions. After completion of the pipeline repairs and the resulting drawdown in inventories, price realizations to date in the second quarter have closely tracked index pricing.

In the first quarter, our cash payout ratio was 48% net of DRIP participation. Under current pricing conditions, we expect to realize FFO in excess of our needs for our exploration and development capital program and our cash dividend payments.

During the first quarter of 2011, we generated net income of $1.0 million. Net income was reduced by the recognition of $46 million in unrealized mark-to-market losses from our WTI hedging program. The FFO impact of those WTI financial contracts could be realized in future periods as those contracts mature.

During the first quarter of 2011, we continued to improve our capital structure through two initiatives. First, we entered into agreements with our lending syndicate to increase the amount of our credit facilities to $650 million (from $550 million), to decrease interest rate margins on advances referenced to prime lending rates, bankers' acceptance rates and LIBOR rates and to decrease standby fees. Second, we issued US$150 million of 10 year senior unsecured debentures at par bearing a coupon rate of 6.75%, and used the net proceeds from this issue to repay a portion of the amount drawn in Canadian currency on our credit facilities.

On February 3, 2011, Baytex completed a previously disclosed heavy oil acquisition for total consideration of $155 million (net of adjustments). The acquisition was funded by drawing on Baytex's existing credit facilities.

At the end of the first quarter of 2011, total monetary debt was $668 million and undrawn credit facilities were $351 million. This level of debt represents a debt-to-FFO ratio of 1.4 times, based on trailing twelve months FFO. All of these debt levels are well within our leverage and liquidity targets, and provide ample capacity to finance our operations.

Conclusion

The first quarter of 2011 was significant for Baytex in several ways. It was our first as Baytex Energy Corp. In our new legal form, we are following the same capital-efficient growth-and-income strategy that we executed in the past few years as Baytex Energy Trust.

We disclosed our independent reserve evaluator's assessment of the net present value of our contingent resource on our three largest resource plays, ranging from a "low estimate" of pre-tax NPV_{10} of $2.5 billion to a "high estimate" of $7.1 billion, with a "best estimate" of $4.4 billion. We feel that this economic analysis is a positive indicator of the measured and capital-efficient development program we are conducting in our resource plays.

Most importantly, we continued very significant oil production growth. While our oil-equivalent volumes (which include our natural gas production converted to oil-equivalent on a 6:1 basis) increased by 8% from year-earlier levels, our oil production increased by 13% over the same period. Measured from the fourth quarter of 2010 to the first quarter of 2011, oil production increased by 6%. Because oil netbacks are a multiple of the netbacks available from natural gas production, we believe that this oil production growth rate is the truest measure of the growth portion of our growth-and-income model. Coupled with the monthly income provided by our dividends, we think that our oil growth can be a meaningful contributor to our total return to investors.

Finally, we have been executing this growth-and-income model while steadily improving our capital structure. Our ability to place US$150 million of 10-year debentures at an interest rate of 6.75% attests to the debt market's confidence in our business model.

It is an honour to serve you, and we want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

Anthony Marino
President and Chief Executive Officer
May 12, 2011

Contingent Resource Assessment

Sproule Associates Limited ("Sproule"), our independent reserves evaluator, prepared an assessment of contingent resource effective December 31, 2010 on three of our oil resource plays: the Bluesky in the Seal area of Alberta, the Bakken/Three Forks in North Dakota and the Viking in southeast Alberta and southwest Saskatchewan.

The contingent resource assessment has been updated by Sproule effective May 1, 2011 to include the net present value of the future net revenue attributable to the contingent resource. The updated assessment of contingent resource does not include the lands at Seal, Alberta that were acquired in the first quarter of 2011.

For the total of these three plays, Sproule's estimate of contingent resource (oil, bitumen, NGL and natural gas) for the three plays ranges from 548 million boe in the "low estimate" (C1) to 1.15 billion boe in the "high estimate" (C3), with a "best estimate" (C2) of 745 million boe. These estimates increased by 3%, 11% and 12%, respectively, as compared to the contingent resource estimates from December 31, 2010 primarily due to the assessment of 1280-acre spacing development in North Dakota and the inclusion of solution gas and NGL volumes on both light oil plays. Contingent resource does not include any volumes currently booked as reserves.

The table below summarizes Sproule's estimates of contingent resource for the three plays by geographic area and the net present value before tax of the future net revenue attributable to the contingent resource using forecast prices and costs.

	Contingent Resource At May 1, 2011(1)		Net Present Value of Future Net Revenue(3) At May 1, 2011 Forecast prices and costs (before income taxes discounted at (%/year))			
	Gross(2) (mmboe)	% Oil, Bitumen and NGL	0%	5%	8%	10%
			($ millions)			
Bluesky – Seal, Alberta						
Low estimate (C1)(4)	478.3	100	9,684.5	4,511.1	2,880.9	2,133.6
Best estimate (C2)(5)	583.3	100	12,856.1	6,173.1	4,043.6	3,060.9
High estimate (C3)(6)	845.9	100	21,783.6	9,559.8	6,038.3	4,492.1
Bakken/Three Forks – North Dakota, USA						
Low estimate (C1)(4)	59.2	90	1,953.6	706.2	404.5	284.0
Best estimate (C2)(5)	138.1	90	7,642.8	2,534.7	1,455.0	1,041.4
High estimate (C3)(6)	253.8	90	16,834.0	5,009.3	2,789.8	1,976.7
Viking – Redwater, Alberta						
Low estimate (C1)(4)	5.4	92	159.1	97.6	73.8	61.5
Best estimate (C2)(5)	11.3	92	548.8	338.8	262.8	224.5
High estimate (C3)(6)	22.7	92	1,290.8	741.7	567.7	484.3
Viking – Dodsland/Kerrobert, Saskatchewan						
Low estimate (C1)(4)	5.1	100	80.3	22.2	9.6	5.0
Best estimate (C2)(5)	12.2	100	430.9	149.6	83.3	57.4
High estimate (C3)(6)	25.7	100	1,336.3	472.1	269.9	190.7
Total						
Low estimate (C1)(4)	548.0	99	11,877.5	5,337.1	3,368.8	2,484.1
Best estimate (C2)(5)	744.9	98	21,478.6	9,196.2	5,844.7	4,384.2
High estimate (C3)(6)	1,148.1	98	41,244.7	15,782.9	9,665.7	7,143.8

(1) *The contingent resource assessment was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101").*

Contingent resource is defined in the COGE Handbook as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets.

Under NI 51-101, naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. The majority of the contingent resource at Seal that will be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resource is classified as bitumen under NI 51-101.

Sproule prepared the estimates of contingent resource shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

(2) *Gross means the company's working interest share in the contingent resource before deducting royalties.*

(3) *The net present value of future net revenue attributable to the contingent resource does not necessarily represent the fair market value of the contingent resource. Estimated abandonment and reclamation costs have been included in the evaluation.*

(4) *Low estimate (C1) is considered to be a conservative estimate of the quantity of resource that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty – a 90% confidence level – that the actual quantities recovered will be equal or exceed the estimate.*

(5) *Best estimate (C2) is considered to be the best estimate of the quantity of resource that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will be equal or exceed the estimate.*

(6) *High estimate (C3) is considered to be an optimistic estimate of the quantity of resource that will actually be recovered. It is unlikely that the actual remaining quantities of resource recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty – a 10% confidence level – that the actual quantities recovered will equal or exceed the estimate.*

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

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at March 31, 2011, inflation and exchange rates utilized by Sproule in the contingent resource assessment were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT MARCH 31, 2011

	Oil			Natural Gas		
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Lloydblend at Hardisty 20.5° API ($Cdn/bbl)	AECO-C ($Cdn/MMbtu)	Inflation Rates(1) (%/year)	Exchange Rate(2) ($US/$Cdn)
2011 (9 months)	103.32	103.14	88.70	3.71	1.5	0.984
2012	102.86	102.65	88.27	4.29	1.5	0.984
2013	100.84	100.57	84.48	4.65	1.5	0.984
2014	95.66	95.29	78.14	5.95	1.5	0.984
2015	95.52	95.14	78.01	6.34	1.5	0.984
2016	96.96	96.57	79.19	6.44	1.5	0.984
2017	98.41	98.03	80.39	6.55	1.5	0.984
2018	99.89	99.51	81.60	6.66	1.5	0.984
2019	101.38	101.02	82.83	6.77	1.5	0.984
2020	102.91	102.54	84.08	6.88	1.5	0.984
2021	104.45	104.09	85.35	6.99	1.5	0.984
Thereafter	Escalation rate of 1.5%					

(1) *Inflation rates for forecasting prices and costs.*

(2) *Exchange rate used to generate the benchmark reference prices in this table.*

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, 2011. This information is provided as of May 11, 2011. 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 2010. This MD&A should be read in conjunction with the Company's unaudited interim condensed consolidated comparative financial statements for the three months ended March 31, 2011 and 2010, and its audited consolidated comparative financial statements for the year ended December 31, 2010 and 2009, together with accompanying notes, and the Annual Information Form for the year ended December 31, 2010. These documents and additional information about Baytex are available on SEDAR at www.sedar.com. The financial statements for the first quarter of 2011 are Baytex's first financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). Comparative periods in 2010 have been restated to conform to IFRS presentation. Reconciliations from IFRS to Canadian general accepted accounting principles ("previous GAAP") are shown in the notes to our financial statements. The adoption of IFRS did not have a material impact on the amounts reported as funds from operations. 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 or per trust unit amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

Corporate Conversion

At year end 2010, Baytex Energy Trust (the "Trust") completed a plan of arrangement under the Business Corporations Act (Alberta) pursuant to which it converted its legal structure from an income trust to a corporation (the "Corporate Conversion"). Pursuant to the Corporate Conversion: (i) on December 31, 2010, holders of trust units of the Trust exchanged their trust units for our common shares on a one-for-one basis; and (ii) on January 1, 2011, the Trust was dissolved and terminated, with the result that we became the successor to the Trust. The reorganization into a corporation has been accounted for on a continuity of interest basis and accordingly, the condensed consolidated financial statements reflect the financial position, results of operations and cash flows as if the Company had always carried on the business formerly carried on by the Trust.

Despite the change in legal structure from a trust to a corporation, the Company's business objectives and strategies remain unchanged and all officers and directors remain the same. Baytex's business objectives are directed towards growing its production and asset base through internal property development and acquisitions with the objectives of providing monthly income to its shareholders and creating long-term value for its shareholders. To achieve these objectives, Baytex intends to invest capital to enhance the value of its assets, operate its producing petroleum and natural gas properties in a low cost manner while maximizing the recovery of reserves, and pay monthly dividends to shareholders.

Baytex will continue to direct its efforts to increase the value of its assets through development drilling and associated development activities and enhanced oil recovery activities as well as by the periodic acquisition of undeveloped and producing petroleum and natural gas properties. Baytex will also seek to acquire petroleum and natural gas producing properties and primarily participate in development activities that are generally considered to be lower risk. Also, a minor percentage of each year's capital budget will be devoted to moderate risk development and lower risk exploration opportunities on its properties.

The common shares of Baytex trade on the Toronto Stock Exchange and the New York Stock Exchange under the trading symbol BTE. Beginning with the January 31, 2011 record date, shareholders of Baytex will receive payments in the form of dividends. Prior to the Corporate Conversion on December 31, 2010, unitholders of the Trust received payments in the form of distributions.

Non-GAAP Financial Measures

Baytex evaluates performance based on net income and funds from operations. Funds from operations is not a measurement based on Generally Accepted Accounting Principles ("GAAP"), but is a financial term commonly used in the petroleum and natural gas industry. Funds from operations represents cash flow from operating activities less finance costs before changes in non-cash working capital and other operating items. The Company's determination of funds from operations may not be comparable with the calculation of similar measures for other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash 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. For a reconciliation of funds from operations to cash flow from operating activities, see "Funds from Operations, Payout Ratio and Dividends or Distributions".

Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred income tax assets or liabilities and unrealized gain or loss on financial derivatives)), the statement of financial position value of convertible debentures, long-term bank loan and principal amount of long-term debt.

Operating netback is a non-GAAP measure commonly used in the oil and gas industry. Operating netback is equal to product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent. This measurement helps management and investors to evaluate the specific operating performance by product. There is no standardized measure of operating netback and therefore operating netback as presented may not be comparable to similar measures presented by other issuers.

Outlook – Economic Environment

The spot price for West Texas Intermediate ("WTI") moved higher over the course of the three months ended March 31, 2011. At March 31, 2011 the spot WTI price was US$106.72/bbl, up from US$91.38/bbl at December 31, 2010. Going forward, Baytex continues to be focused on the following objectives: preserving financial position strength and liquidity, maintaining and, where possible, profitably expanding its productive capacity and delivering a stable dividend to its shareholders.

Results of Operations

Production

	Three Months Ended March 31		
	2011	2010	Change
Daily Production			
Light oil and NGL (bbl/d)	**6,606**	6,660	(1%)
Heavy oil (bbl/d)(1)	**31,792**	27,278	17%
Natural gas (mmcf/d)	**51.0**	56.9	(10%)
Total production (boe/d)	**46,902**	43,425	8%
Production Mix			
Light oil and NGL	**14%**	15%	
Heavy oil	**68%**	63%	
Natural gas	**18%**	22%	

(1) Heavy oil sales volumes may differ from reported production volumes due to changes to the Company's heavy oil inventory. For the three months ended March 31, 2011, heavy oil sales volumes were 576 bbl/d higher than production volumes (three months ended March 31, 2010 – 163 bbl/d higher).

Production for the three months ended March 31, 2011 totaled 46,902 boe/d, as compared to 43,425 boe/d for the same period in 2010. Light oil and natural gas liquids ("NGL") production of 6,606 bbl/d for the first quarter of 2011 decreased from 6,660 bbl/d in the same period last year as light oil and NGL declines in conventional fields were largely offset by production increases from light oil resource plays. Heavy oil production for the first quarter of 2011 increased by 17% to 31,792 bbl/d from 27,278 bbl/d in the same period last year primarily due to increased production from development programs and the acquisition of producing assets. Natural gas production decreased by 10% to 51.0 mmcf/d for the first quarter of 2011, as compared to 56.9 mmcf/d for the same period last year primarily due to natural declines as we focused our drilling effort on our oil portfolio.

Commodity Prices

Crude Oil

For the three months ended March 31, 2011, the price of WTI fluctuated between a low of US$84.32/bbl and a high of US$106.72/bbl. For much of the first half of the quarter, WTI price fluctuated in the US$85.00/bbl to US$92.00/bbl range, retaining much of the price increase seen in the fourth quarter of 2010, due to increasing oil demand from emerging markets. In late February 2011, political turmoil in the Middle East/North Africa pushed WTI above US$100.00/bbl, a level not seen since 2008. In a surprisingly short span of time, popular uprisings threatened several governments across the Middle East/North Africa region. As concerns mounted over future oil supply disruptions, civil war erupted in Libya curtailing over one million barrels of light sweet crude oil exports from that country. Against a backdrop of rising global oil demand and ongoing turmoil in the Middle East/North Africa region causing supply uncertainties, WTI ended the first quarter of 2011 at a high of US$106.72/bbl.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 24.3% in the first quarter of 2011, compared to 21.5% in the fourth quarter of 2010, and 12.0% in the first quarter of 2010. Continuing export pipeline integrity issues led to a surplus of Canadian heavy oil, which was reflected in the higher WCS discounts during the first quarter of 2011. However, pipeline maintenance and repairs performed this quarter should improve future Canadian heavy oil export capacity and market access. During the first quarter of 2011, Baytex's realized heavy oil price was negatively impacted by local market conditions, which resulted from producers attempting to avoid pipeline apportionment issues. These conditions have largely been resolved for the second quarter of 2011.

Natural Gas

For the three months ended March 31, 2011, AECO natural gas prices averaged $3.77/mcf, as compared to $5.36/mcf in the same period last year. Although cold winter weather increased gas demand in North America, this was offset by continued growth in the supply of natural gas in the U.S. and a strengthening Canadian dollar.

	Three Months Ended March 31		
	2011	2010	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	$ 94.10	$ 78.71	20%
WCS heavy oil (US$/bbl)(2)	$ 71.24	$ 69.67	2%
Heavy oil differential(3)	(24.3%)	(12.0%)	
USD/CAD average exchange rate	1.0142	0.9607	6%
Edmonton par oil ($/bbl)	$ 88.45	$ 80.31	10%
AECO natural gas price ($/mcf)(4)	$ 3.77	$ 5.36	(30%)
Baytex Average Sales Prices(6)			
Light oil and NGL ($/bbl)	$ 75.68	$ 68.04	11%
Heavy oil ($/bbl)(5)	$ 57.83	$ 64.46	(10%)
Physical forward sales contracts gain (loss) ($/bbl)	2.06	(2.39)	
Heavy oil, net ($/bbl)	$ 59.89	$ 62.07	(4%)
Total oil and NGL, net ($/bbl)	$ 62.57	$ 63.24	(1%)
Natural gas ($/mcf)(6)	$ 3.92	$ 5.31	(26%)
Physical forward sales contracts gain ($/mcf)	0.27	–	
Natural gas, net ($/mcf)	$ 4.19	$ 5.31	(21%)
Summary			
Weighted average ($/boe)(6)	$ 53.90	$ 58.18	(7%)
Physical forward sales contracts gain (loss) ($/boe)	1.96	(1.77)	
Weighted average, net ($/boe)	$ 55.86	$ 56.41	(1%)

(1) WTI refers to the calendar monthly 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 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 pricing information in the table excludes the impact of financial derivatives.

During the first quarter of 2011, Baytex's average sales price for light oil and NGL was $75.68/bbl, up 11% from $68.04/bbl in the first quarter of 2010. Baytex's realized heavy oil price during the first quarter of 2011, prior to physical forward sales contracts, was $57.83/bbl, or 82% of WCS. This compares to a realized heavy oil price in the first quarter of 2010, prior to physical forward sales contracts, of $64.46/bbl, or 89% of WCS. The differential to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the first quarter of 2011 was $59.89/bbl, down 4% from $62.07/bbl in the first quarter of 2010 due to the higher differential to WCS compared to the same period in 2010. Baytex's realized natural gas price for the three months ended March 31, 2011 was $3.92/mcf, prior to physical forward sales contracts, and $4.19/mcf inclusive of physical forward sales contracts (three months ended March 31, 2010 – $5.31/mcf prior to and inclusive of physical forward sales contracts).

Gross Revenues

($ thousands except for %)	Three Months Ended March 31 2011	2010	Change
Oil revenues			
Light oil and NGL	$ 44,994	$ 40,784	10%
Heavy oil	174,470	153,291	14%
Total oil revenues	219,464	194,075	13%
Natural gas revenues	19,236	27,222	(29%)
Total oil and natural gas revenues	238,700	221,297	8%
Sales of heavy oil blending diluent	51,615	40,485	27%
Total petroleum and natural gas sales	$ 290,315	$ 261,782	11%

Petroleum and natural gas sales increased 11% to $290.3 million for the first quarter of 2011 from $261.8 million for the same period in 2010. During the three months ended March 31, 2011, the increase in gross revenues were mainly driven by a 13% increase in total oil and NGL production volumes, slightly offset by a 1% decrease in total oil and NGL sales price compared to the three months ended March 31, 2010.

Royalties

($ thousands except for % and per boe)	Three Months Ended March 31 2011	2010	Change
Royalties	$ 48,802	$ 50,965	(4%)
Royalty rates:			
Light oil, NGL and natural gas	18.9%	22.6%	
Heavy oil	20.9%	23.2%	
Average royalty rates[(1)]	20.3%	23.0%	
Royalty expenses per boe	$ 11.42	$ 12.99	(12%)

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

Total royalties for the first quarter of 2011 decreased 4% to $48.8 million from $51.0 million in the first quarter of 2010. Total royalties for the first quarter of 2011 averaged 20.3% of petroleum and natural gas revenues (excluding sales of heavy oil blending diluent), as compared to 23.0% for the same period in 2010.

Royalties as a percentage of revenues for light oil, NGL and natural gas decreased in the current quarter compared to the first quarter of 2010 mainly due to a 21% decrease in realized natural gas price. Royalties as a percentage of revenues for heavy oil in the three months ended March 31, 2011 were lower than the same period in 2010 due to lower royalties for new and existing production at Seal.

Certain additional credits earned under the Alberta Royalty Drilling Credit program, which are based on drilling activity and drilling depths, are recorded as a reduction to capital expenditures, rather than as a reduction to royalties.

Financial Derivatives

($ thousands)	Three Months Ended March 31 2011	2010	Change
Realized gain (loss) on financial derivatives(1)			
Crude oil	$ (4,433)	$ 1,305	$ (5,738)
Natural gas	(10)	900	(910)
Foreign currency	6,102	6,447	(345)
Interest rate	(72)	511	(583)
Total	$ 1,587	$ 9,163	$ (7,576)
Unrealized gain (loss) on financial derivatives(2)			
Crude oil	$ (48,791)	$ (3,172)	$ (45,619)
Natural gas	408	6,532	(6,124)
Foreign currency	1,380	5,055	(3,675)
Interest rate	533	(5,192)	5,725
Total	$ (46,470)	$ 3,223	$ (49,693)
Total gain (loss) on financial derivatives			
Crude oil	$ (53,224)	$ (1,867)	$ (51,357)
Natural gas	398	7,432	(7,034)
Foreign currency	7,482	11,502	(4,020)
Interest rate	461	(4,681)	5,142
Total	$ (44,883)	$ 12,386	$ (57,269)

(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 total loss on financial derivatives for the first quarter was $44.9 million, as compared to a gain of $12.4 million in the first quarter of 2010. This includes realized gains of $1.6 million and unrealized mark-to-market losses of $46.5 million for the first quarter of 2011, as compared to $9.2 million in realized gains and $3.2 million in unrealized mark-to-market gains for the first quarter of 2010. The realized gain of $1.6 million for the three months ended March 31, 2011 is mainly due to the settlement of gains on favorable foreign currency derivatives, partially offset by losses on crude oil derivatives. The unrealized mark-to-market loss of $46.5 million for the three months ended March 31, 2011 is mainly due to higher expected future crude oil prices at March 31, 2011, as compared to December 31, 2010.

Details of the risk management contracts in place as at March 31, 2011 and the accounting treatment of the Company's financial instruments are disclosed in note 22 to the unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2011.

Evaluation and Exploration Expense

Evaluation and exploration expense for the first quarter of 2011 decreased to $3.5 million from $5.8 million for the same period of 2010 due to a decrease in lease expiries of undeveloped land for the first quarter of 2011.

Production and Operating Expenses

($ thousands except for % and per boe)	Three Months Ended March 31 2011	2010	Change
Production and operating expenses	$ 47,476	$ 42,234	12%
Production and operating expenses per boe	$ 11.11	$ 10.77	3%

Production and operating expenses for the first quarter of 2011 increased to $47.5 million from $42.2 million for the same period of 2010 due to difficult winter operating conditions, which increased the cost of energy inputs and snow plow removal. Production and operating expenses were $11.11 per boe for the first quarter of 2011, as compared to

$10.77 per boe for the first quarter of 2010. For the first quarter of 2011, production and operating expenses were $11.28 per boe of light oil, NGL and natural gas and $11.03 per barrel of heavy oil, as compared to $11.79 and $10.16, respectively, for the first quarter of 2010.

Transportation and Blending Expenses

($ thousands except for % and per boe)	Three Months Ended March 31 2011	2010	Change
Blending expenses	$ 51,615	$ 40,485	27%
Transportation expenses	12,545	11,554	9%
Total transportation and blending expenses	$ 64,160	$ 52,039	23%
Transportation expense per boe[1]	$ 2.94	$ 2.95	–%

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

Transportation and blending expenses for the first quarter of 2011 were $64.2 million, as compared to $52.0 million for the first quarter of 2010.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex mainly purchases condensate from industry producers as the blending diluent to facilitate the marketing of its heavy oil. In the first quarter of 2011, the blending cost was $51.6 million for the purchase of 5,870 bbl/d of condensate at $97.71 per barrel, as compared to $40.5 million for the purchase of 5,198 bbl/d at $86.54 per barrel for the same period last year. The cost of blending diluent is effectively recovered in the sale price of the blended product.

Transportation expenses before blending costs were $2.94 per boe for the first quarter of 2011, which is consistent compared to $2.95 per boe for the same period of 2010. Transportation expenses were $0.73 per boe of light oil, NGL and natural gas and $3.97 per barrel of heavy oil in the first quarter of 2011, as compared to $0.83 and $4.19, respectively, for the same period in 2010.

Operating Netback

($ per boe except for % and volume)	Three Months Ended March 31 2011	2010	Change
Sales volume (boe/d)	47,478	43,588	9%
Operating netback[1]:			
Sales price[2]	$ 55.86	$ 56.41	(1%)
Less:			
Royalties	11.42	12.99	(12%)
Production and operating expenses	11.11	10.77	3%
Transportation expenses	2.94	2.95	–%
Operating netback before financial derivatives	$ 30.39	$ 29.70	2%
Financial derivative gains[3]	0.37	2.34	(84%)
Operating netback after financial derivatives	$ 30.76	$ 32.04	(4%)

(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 financial derivative gains (losses) only.

General and Administrative Expenses

	Three Months Ended March 31		
($ thousands except for % and per boe)	2011	2010	Change
General and administrative expenses	$ 11,130	$ 11,131	–%
General and administrative expenses per boe	$ 2.60	$ 2.84	(8%)

General and administrative expenses of $11.1 million for the first quarter of 2011 were consistent with the same period in 2010. Although in aggregate there was little change in general and administrative expenses for first quarter of 2011, as compared to the first quarter 2010, office rent and higher salary costs were higher for the three months ended March 31, 2011. In addition, $0.4 million of transaction costs related to property and corporate acquisitions were incurred and expensed. General and administrative expenses in the first quarter of 2010 included a $1.9 million payment for a non-recurring tax indemnification relating to the Trust Unit Rights Incentive Plan of the Trust (the "Unit Rights Plan"). Excluding transaction costs related to the property and corporate acquisition general and administrative expenses per boe for the three months ended March 31, 2011 would have been $2.50 per boe, as compared to $2.35 per boe for three months ending March 31, 2010 (excluding the non-recurring tax indemnification payment).

Share-based Compensation Expense

Compensation expense related to the Common Share Rights Incentive Plan (the "Share Rights Plan") was $5.3 million for the first quarter of 2011, as compared to $31.9 million related to the Unit Rights Plan for the first quarter of 2010. The decrease in compensation expense is due to the classification, in 2010, of the Unit Rights Plan as a liability and the requirement to remeasure the fair value of the liability at each reporting date and at settlement. Any changes in fair value were recognized in net income for the period. Upon conversion to a corporation, at year end 2010, the Share Rights Plan replaced the Unit Rights Plan and the classification of the Share Rights Plan was determined to be equity settled. As such, the expense recognized over the remainder of the vesting period from the date of modification of the Unit Rights Plan into the Share Rights Plan is determined based on the fair value of the reclassified share rights at the date of such modification.

On January 1, 2011, the Company 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. During the three months ended March 31, 2011 the Company recorded compensation expense of $2.7 million related to the share awards ($nil for the three months ended March 31, 2010). This increase is the result of the compensation expense related to Share Awards granted in the first quarter of 2011.

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

Finance Costs

Finance costs for the first quarter of 2011 increased to $10.6 million, as compared to $7.6 million in the first quarter of 2010. The increase in finance costs was primarily attributable to the interest on the US$150.0 million principal amount of Series B senior unsecured debentures bearing interest at 6.75%, $0.5 million of interest incurred related to the property acquisition, and a higher bank loan balance and prime lending rate compared to the first quarter of 2010.

Foreign Exchange

($ thousands)	Three Months Ended March 31 2011	2010	Change
Unrealized foreign exchange gain	$ (4,856)	$ (4,850)	–%
Realized foreign exchange loss	926	924	–%
Total gain	$ (3,930)	$ (3,926)	–%

The foreign exchange gain in both of the first quarter of 2011 and 2010 were $3.9 million. This gain was comprised of an unrealized foreign exchange gain of $4.9 million and a realized foreign exchange loss of $0.9 million. The first quarter unrealized gain of $4.9 million in 2011 and 2010 were due to the translation of the US$180 million portion of the bank loan as the CAD/USD foreign exchange rates strengthened at March 31, 2011 (as compared to December 31, 2010) and March 31, 2010 (as compared to December 31, 2009). The current quarter realized loss was related to US$ denominated financial derivative contract losses and was partially offset by gains on day-to-day US$ denominated transactions.

Depletion and Depreciation

Depletion and depreciation for the three months ended March 31, 2011 increased to $56.6 million from $47.9 million for the same period in 2010. On a sales-unit basis, the provision for the current quarter was $13.61 per boe, as compared to $12.57 per boe for the same quarter in 2010.

Income Taxes

For the first quarter of 2011, deferred income tax recovery totaled $1.8 million, as compared to a recovery of $1.0 million for the first quarter of 2010. The increase in deferred income tax recovery is primarily due to a recognition of the lower deferred tax rate in the current quarter.

As at March 31, 2011, deferred income tax liability was $253.6 million (December 31, 2010 – $286.8 million) and a deferred income tax asset of $225.3 million (December 31, 2010 – $280.3 million). The main increase relates to the additional liability recognized in the corporate acquisition.

Tax Pools

During 2010 and prior years, Baytex was organized as a mutual fund trust for Canadian income tax purposes. Partially as a result of tax deductions taken for distributions paid to unitholders in 2010 and prior years, no material Canadian cash tax expense, other than the Saskatchewan resource surcharge, was payable by the Trust, which is classified as a royalty expense under IFRS.

Following the conversion from a trust structure to a corporate legal form on December 31, 2010, Baytex will not be entitled to a deduction from Canadian taxable income for its distributions, nor will a deduction be available for future dividends. As such, it is likely that cash income tax expense attributable to our Canadian operations will be higher in future. Baytex has accumulated the Canadian and U.S. tax pools as noted in the table below, which will be available to reduce future taxable income. Our cash income tax liability is dependant upon many factors, including the prices at which we sell our production, available income tax deductions, and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and the proposed legislation on partnership deferral, Baytex expects to become liable for Canadian income tax in 2012. The income tax pools detailed below are deductible at various rates as prescribed by law.

($ thousands)	March 31, 2011	December 31, 2010
Canadian Tax Pools		
Canadian oil and gas property expenditures	$ 402,371	$ 271,741
Canadian development expenditures	270,563	292,500
Canadian exploration expenditures	8,818	11,757
Undepreciated capital costs	182,424	184,586
Non-capital losses	529,374	775,727
Finance costs	9,201	10,334
Total Canadian tax pools	$ 1,402,751	$ 1,546,645
U.S. Tax Pools		
Taxable depletion	$ 160,714	$ 125,628
Intangible drilling costs	14,446	35,000
Tangibles	3,498	3,634
Non-capital losses	66,530	66,530
Total U.S. tax pools	$ 245,188	$ 230,792

Net Income

Net income for the first quarter of 2011 was $1.0 million, as compared to $29.5 million for the first quarter of 2010. The decrease in net income was primarily the result of a $46.5 million unrealized loss on financial derivatives, partially mitigated by the increase in production volume coupled with a higher operating netback and lower share-based compensation expense for the current period.

Other Comprehensive Loss

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'/unitholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

Under IFRS, the Company has elected to deem cumulative currency translation differences as $nil at January 1, 2010. The $15.3 million balance of accumulated other comprehensive loss at March 31, 2011 is the sum of a $10.3 million foreign currency translation loss incurred in 2010 and a $5.0 million foreign currency translation loss incurred in the current quarter.

Funds from Operations, Payout Ratio and dividends or distribution

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities less finance costs before changes in non-cash working capital and other operating items. Payout ratio is calculated as cash dividends/distributions (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, 2011	December 31, 2010	March 31, 2010	December 31, 2010
Cash flow from operating activities	$ 119,899	$ 108,264	$ 102,055	$ 459,732
Change in non-cash working capital	(2,392)	21,156	9,633	13,399
Asset retirement expenditures	919	802	611	2,829
Finance costs	(10,562)	(8,683)	(7,623)	(34,570)
Accretion on asset retirement obligations	1,484	1,531	1,419	5,862
Accretion on debentures and long-term debt	122	91	112	426
Funds from operations	$ 109,470	$ 123,161	$ 106,207	$ 447,678
Cash dividends or distributions declared, net of DRIP	$ 52,002	$ 48,126	$ 49,142	$ 189,824
Payout ratio	48%	39%	46%	42%

Baytex does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of petroleum and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the petroleum and natural gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, it is possible that Baytex would be required to reduce or eliminate its dividends in order to fund capital expenditures. There can be no certainty that Baytex will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $52.0 million for the first quarter of 2011 were funded through funds from operations of $109.5 million.

The following table compares cash dividends or distributions to cash flow from operating activities and net income:

	Three Months Ended			Year Ended
($ thousands except for %)	March 31, 2011	December 31, 2010	March 31, 2010	December 31, 2010
Cash flow from operating activities	$ 119,899	$ 108,264	$ 102,055	$ 459,732
Cash dividends or distributions declared, net of DRIP	52,002	48,126	49,142	189,824
Excess of cash flow from operating activities over cash dividends or distributions declared, net of DRIP	$ 67,897	$ 60,138	$ 52,913	$ 269,908
Net income	$ 950	$ 21,356	$ 29,501	$ 231,615
Cash dividends or distributions declared, net of DRIP	52,002	48,126	49,142	189,824
Excess (shortfall) of net income over cash dividends or distributions declared, net of DRIP	$ (51,052)	$ (26,770)	$ (19,641)	$ 41,791

It is Baytex's long-term operating objective to substantially fund cash dividends and capital expenditures for exploration and development activities through funds from operations. Future production levels are highly dependent upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized, are the main factors influencing the sustainability of our cash dividends. During periods of lower commodity prices or periods of higher capital spending, it is possible that funds from operations will not be sufficient to fund both cash dividends and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing.

As at March 31, 2011, Baytex had approximately $351.4 million in available undrawn credit facilities to fund any such shortfall.

For the three months ended March 31, 2011, the Company's net income was less than cash dividends declared (net of DRIP) by $51.1 million, with net income reduced by $118.9 million for non-cash items. Non-cash items such as depletion and depreciation may not be fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

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, 2011	December 31, 2010
Bank loan	$ 298,591	$ 303,773
Long-term debt(1)	295,770	150,000
Working capital deficiency	73,709	52,462
Total monetary debt	$ 668,070	$ 506,235

(1) Principal amount of long-term debt.

At March 31, 2011, total monetary debt was $668.1 million, as compared to $506.2 million at December 31, 2010. Bank borrowings at March 31, 2011 were $298.6 million, as compared to the available total credit facilities of $650.0 million.

Our wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established credit facilities with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. On January 1, 2011, Baytex Energy reached agreement with its lending syndicate to increase the amount of the credit facilities to $625.0 million (from $550.0 million), to decrease its margins on advances based on the prime lending rate, bankers' acceptance rates or LIBOR rates and to decrease standby fees. The credit facilities were further increased to $650.0 million on February 17, 2011. In the event that the revolving period is not extended by June 2011, all amounts then outstanding under the credit facilities will be payable in June 2012. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates or LIBOR rates, plus applicable margins. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex Energy's assets. The weighted average interest rate on the bank loan for the three months ended March 31, 2011 was 3.84% (year ended December 31, 2010 – 4.60%, three months ended March 31, 2010 – 3.84%).

The credit facilities were arranged pursuant to an agreement with a syndicate of chartered banks. A copy of the credit agreement and related amendments are accessible on the SEDAR website at www.sedar.com (filed on March 28, 2008, September 15, 2008, July 9, 2009, August 14, 2009, October 5, 2009, July 15, 2010, August 31, 2010, January 10, 2011 and February 24, 2011).

On February 17, 2011, Baytex issued US$150.0 million principal amount of Series B senior unsecured debentures bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. Net proceeds of this issue were used to repay a portion of the amount drawn in Canadian currency on Baytex Energy's credit facilities. These debentures are unsecured and are subordinate to Baytex Energy's credit facilities.

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 the Series A or Series B senior unsecured debentures and the 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)	2011	2010
Land	$ 2,225	$ 4,574
Seismic	123	(286)
Drilling and completion	63,195	37,994
Equipment	21,431	13,094
Other	40	(20)
Total exploration and development	$ 87,014	$ 55,356
Acquisition – Corporate	117,346	–
Acquisition – Properties	37,518	2,333
Total acquisitions	$ 154,864	$ 2,333
Total oil and gas expenditures	$ 241,878	$ 57,689
Other plant and equipment, net	(275)	4,839
Total capital expenditures	$ 241,603	$ 62,528

Shareholders' Capital

On December 31, 2010, all of the outstanding trust units of the Trust were exchanged for common shares of Baytex on a one-for-one basis in connection with the Corporate Conversion.

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 5, 2011, the Company had 115,524,675 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 through funds from operations. These obligations as of March 31, 2011, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-2 years	3-5 years	Beyond 5 years
Trade and other payables	$ 233,062	$ 233,062	$ –	$ –	$ –
Dividends payable to shareholders	23,035	23,035	–	–	–
Bank loan[1]	298,591	–	298,591	–	–
Long-term debt[2]	295,770	–	–	–	295,770
Operating leases	54,278	5,745	11,511	12,335	24,686
Processing and transportation agreements	3,156	2,256	885	15	–
Total	$ 907,892	$ 264,098	$ 310,987	$ 12,350	$ 320,456

(1) The bank loan is a 364-day revolving loan with a one year term-out following the 364-day revolving period with the ability to extend the term. Unless extended, the revolving period will end on June 27, 2011 with all amounts to be re-paid by June 27, 2012.

(2) Principal amount of long-term debt.

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.

Details of the risk management contracts in place as at March 31, 2011 and the accounting treatment of the Company's financial instruments are disclosed in note 22 to the unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2011.

Quarterly Financial Information

	2011	2010				2009 – Previous GAAP[1]		
($ thousands, except per common share or trust unit amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Gross revenues	**290,315**	263,497	238,293	241,564	261,782	237,962	208,206	193,239
Net income	**950**	21,356	23,319	157,439	29,501	27,956	40,657	27,451
Per common share or trust unit – basic	**0.01**	0.19	0.21	1.42	0.27	0.26	0.38	0.26
Per common share or trust unit – diluted	**0.01**	0.18	0.20	1.38	0.26	0.25	0.37	0.26

(1) 2009 previous GAAP quarterly financial information not restated to IFRS.

Changes in Accounting Policies

Adoption of International Financial Reporting Standards

IFRS replaces GAAP in Canada for financial periods beginning on January 1, 2011. At the transition date, publicly accountable enterprises are required to prepare financial statements in accordance with IFRS. The adoption date of January 1, 2011 requires the restatement, for comparative purposes, of 2010 amounts reported by Baytex, including the opening statement of financial position as at January 1, 2010.

Our IFRS financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore our interim condensed consolidated financial statements have been prepared using the standards expected to be effective at the end of 2011. IFRS accounting policies will only be finalized when our first annual IFRS financial statements are prepared for the year ending December 31, 2011 and as a result, our interim condensed consolidated financial statements for the three months ended March 31, 2011 are subject to change. Reconciliations to IFRS from the previously published consolidated financial statements, prepared in accordance with previous GAAP are shown in note 23 to the interim condensed consolidated financial statements. The accounting policies described in note 3 to the interim condensed consolidated financial statements set out those policies that have been applied retrospectively and consistently in preparing the condensed consolidated financial statements, except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1 (as disclosed in note 23 to the interim condensed consolidated financial statements).

The following table reconciles Baytex's 2010 previous GAAP results to IFRS for the year ended December 31, 2010 and the three months ended March 31, 2010.

	2010	
	Annual	Q1
Net income – Previous GAAP	$ 177,631	$ 51,954
Exploration and evaluation	(24,502)	(5,846)
Depletion and depreciation	63,731	17,045
Divestiture of oil and gas assets	16,209	–
Accretion on asset retirement obligation	(1,347)	(327)
Unit-based compensation	(85,855)	(29,460)
Conversion feature of convertible debentures	(5,118)	(2,551)
Deferred income tax	92,180	(1,281)
Other	(1,314)	(33)
Net income – IFRS	$ 231,615	$ 29,501

	2010	
	Annual	Q1
Funds from operations – Previous GAAP	$ 454,183	$ 107,498
Exploration and evaluation	(5,589)	(1,353)
Other	(916)	62
Funds from operations – IFRS	$ 447,678	$ 106,207

Listed below is a summary of the significant effects of the transition from previous GAAP to IFRS:

Exploration and Evaluation

Under previous GAAP, petroleum and natural gas properties included certain exploration and evaluation expenditures incurred within a country-by-country cost centre. Under IFRS, such exploration and evaluation expenditures are recognized as tangible or intangible based on their nature and subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are expensed.

Exploration and evaluation assets at January 1, 2010 were deemed to be $124.6 million, being the amount recorded as the undeveloped land balance under previous GAAP. This has resulted in the reclassification from property, plant and equipment to intangible exploration assets of $124.6 million in the opening IFRS statement of financial position.

During the year ended December 31, 2010, Baytex transferred exploration and evaluation expense of $29.1 million to oil and gas properties and expensed $18.9 million of exploration and evaluation assets related to lease expiries and $5.6 million in direct exploration costs. For the three months ended March 31, 2010, Baytex transferred exploration and evaluation expense of $7.2 million to oil and gas properties and expensed $4.5 million of exploration and evaluation assets related to lease expiries and $1.3 million in direct exploration costs.

Depletion

Upon transition to IFRS, the Company adopted a policy of depleting oil and gas properties on a "units of production" basis over proved plus probable reserves at a more componentized area basis than under previous GAAP. The depletion policy under previous GAAP was units of production over proved reserves on a country basis.

There is no impact to depletion on transition of IFRS at January 1, 2010. For the year ended December 31, 2010, this resulted in a decrease in depletion expense of $67.4 million with a corresponding increase in oil and gas properties (three months ended March 31, 2010 – decrease in depletion of $17.9 million).

Divestiture of Oil and Gas Assets

Previous GAAP utilized the full cost accounting, whereby gains and losses were not recognized upon the divestiture of oil and gas assets unless such a divestiture would alter the rate of depletion by 20% or more. Under IFRS, gains and losses are recognized based on the difference between the net proceeds from the divestiture and the carrying value of the asset disposed. For the year ended December 31, 2010, a gain of $16.2 million was recognized relating to a divestiture of oil and gas assets.

Impairment of Property, Plant and Equipment ("PP&E") Assets

Under IFRS, impairment of PP&E must be calculated at a more detailed level than what was required under previous GAAP. Impairment calculations are performed at the cash generating unit ("CGU") level using the higher of its fair value less costs to sell and its value in use. Baytex uses discounted estimated cash flows from proved plus probable reserves for impairment tests of PP&E. Under previous GAAP, estimated future net cash flows used to assess impairments were not discounted. As such, impairment losses may be recognized earlier under IFRS than under previous GAAP. Impairment losses are reversed under IFRS when there is an increase in the recoverable amount.

Baytex has allocated the PP&E amount recognized under previous GAAP as at January 1, 2010 to the assets at a CGU level using reserve values calculated using the discounted net cash flows. There is no change in the overall net book value of our PP&E as there were no impairments upon adoption to IFRS at January 1, 2010.

Asset Retirement Obligations

Under IFRS, Baytex uses a risk-free interest rate to discount the estimated fair value of its asset retirement obligations associated with the related oil and gas properties. Under previous GAAP, the Company used a credit-adjusted interest rate. A lower discount rate under IFRS will increase the asset retirement obligations. In addition, under IFRS the asset retirement obligations are measured using the best estimate of the expenditure to be incurred and uses current discount rates at each re-measurement date with the corresponding adjustment to the cost of the related oil and gas properties. Existing liabilities under previous GAAP are not remeasured using current discount rates.

Under previous GAAP, the Company's asset retirement obligations were recorded using the credit-adjusted risk free rate of 8.0%. Under IFRS, the Company's asset retirement obligations are recorded using the risk-free rate of 3.5% at December 31, 2010 (4.0% at January 1, 2010). Under IFRS, an additional liability of $87.3 million was charged to deficit at January 1, 2010. At December 31, 2010, excluding the January 1, 2010 adjustment, the lower discount rates used resulted in an additional liability of $29.9 million and a resulting $28.6 million increase to the related oil and gas properties.

For the twelve months ended December 31, 2010, the $4.5 million accretion expense on asset retirement obligations under previous GAAP was reclassified to finance costs and an additional accretion expense on asset retirement obligations of $1.3 million has been recognized in net income under IFRS (three months ended March 31, 2010 – $1.1 million reclassified and an additional accretion expense of $0.3 million).

Unit-based Compensation

Under previous GAAP, the obligation associated with the Unit Rights Plan is considered to be equity-based and the related unit-based compensation was calculated using the binomial-lattice model to estimate the fair value of the outstanding unit rights at grant date. The exercise of unit rights was recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Under IFRS, prior to the conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability is remeasured at each reporting date and at settlement date. Any changes in fair value are recognized in net income for the period. For periods prior to the conversion to a corporation, remeasuring the fair value of the obligation each reporting period will increase or decrease the unit-based payment liability, unitholders' capital and compensation expense recognized. Upon conversion to a corporation, the outstanding Unit Rights Plan was modified to become the new Share Rights Plan, effectively changing the related classification from liability-settled to equity-settled. The expense recognized from the date of the plan modification over the remainder of the vesting period is determined based on the fair value of the reclassified unit rights at the date of the modification. Upon transition of IFRS at January 1, 2010, an additional unit-based payment liability of $91.6 million and a decrease of $20.4 million in contributed surplus had a corresponding $71.2 million charge to deficit.

Under IFRS, in addition to the January 1, 2010 adjustments discussed above, at December 31, 2010 the remeasurement of the liability at reporting date and at settlement date resulted in an additional unit-based compensation expense of $85.9 million recognized, with a corresponding decrease of $0.3 million in contributed surplus, an increase of $48.0 million in shareholders'/unitholders' equity and an increase of $37.6 million in unit-based payment liability. At December 31, 2010, the $129.1 million balance in unit-based payment liability was transferred to contributed surplus in conjunction with the corporate conversion.

Conversion Feature of Convertible Debentures

Under previous GAAP, the convertible debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' or shareholders' equity. The debt portion accreted up to the principal balance at maturity. If the debentures were converted to trust units, a portion of the value of the conversion feature under unitholders' equity was reclassified to unitholders' capital along with principal amounts converted.

Under IFRS, the conversion feature of the convertible debentures has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the derivative liability are recognized in the statements of income and comprehensive income. If the debentures were converted to trust units, the fair value of the conversion feature under financial derivative liability was reclassified to unitholders'/shareholders' capital along with the principal amounts converted. The impact on adoption to IFRS at January 1, 2010 was an additional liability of $7.4 million, an increase of $33.4 million in unitholders' capital with a corresponding $40.4 million charge to deficit and a decrease of $0.4 million in the conversion feature of convertible debentures.

Under IFRS, for the year ended December 31, 2010, the increase in unitholders'/shareholders' equity of $12.1 million and the increase of $0.4 million in conversion feature of convertible debentures had a corresponding decrease in the $7.4 million liability recorded at January 1, 2010 and a $5.1 million decrease in gain on financial derivatives in net income.

Accumulated Other Comprehensive Loss

Under previous GAAP, amounts are composed entirely of currency translation adjustments on self-sustaining foreign operations. Under IFRS, the Company has elected to deem cumulative currency translation differences as

$nil at January 1, 2010. At January 1, 2010, this has resulted in an decrease in accumulated other comprehensive loss with a corresponding increase in deficit of $3.9 million.

Deferred Income Taxes

Under IFRS, deferred income taxes are required to be presented as non-current. Upon transition to IFRS, the Company recognized a $27.6 million reduction in the net deferred income tax liability entirely resulting from the tax impact of the adjustments from previous GAAP to IFRS with a decrease to deficit of $25.8 million and a decrease to unitholders' capital of $1.8 million.

Baytex acquired several private entities to be used in its internal financing structure. Under previous GAAP, the excess of amounts assigned to the acquired assets over the consideration paid is classified as a deferred credit. Under IFRS, the deferred credit is derecognized through net income as a deferred income tax recovery. For the year ended December 31, 2010, a deferred income tax recovery of $109.8 million was recorded in net income for amounts previously recognized as a deferred credit.

For the year ended December 31, 2010, the application of the IFRS adjustments resulted in a $92.2 million decrease to the Company's deferred income tax expense. Under IFRS, taxable and deductible temporary differences related to the legal entity of the Trust must be measured using the highest marginal personal tax rate of 39%, as opposed to the corporate tax rates used under previous GAAP, resulting in an increase to the deferred income tax asset of $5.1 million at January 1, 2010. Upon conversion to a dividend paying corporation on December 31, 2010, the total deferred income tax asset related to the Trust was adjusted to the corporate tax rate of approximately 25% and derecognized through net income on December 31, 2010.

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 ability to utilize our tax pools to reduce or potentially eliminate our taxable income for the initial period post-conversion; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; funding sources for our cash dividends and capital program; the timing of funding our financial obligations; the existence, operation, and strategy of our risk management program; the impact of the adoption of new accounting standards on our financial results; and the impact of the adoption of IFRS on our financial position and results of operations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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 availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain *circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.*

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; 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, 2010, 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

(thousands of Canadian dollars) (unaudited)	**March 31, 2011**	December 31, 2010	January 1, 2010
ASSETS			
Current assets			
Cash	**$ 3,972**	$ –	$ 10,177
Trade and other receivables (note 6)	**178,416**	151,792	137,154
Crude oil inventory	**–**	1,802	1,384
Financial derivatives (note 22)	**14,162**	13,921	29,453
	196,550	167,515	178,168
Non-current assets			
Deferred income tax asset (note 18)	**225,256**	280,276	53,416
Financial derivatives (note 22)	**3,093**	2,622	2,541
Exploration and evaluation assets (note 7)	**127,952**	113,082	124,621
Oil and gas properties (note 8)	**1,815,851**	1,624,629	1,512,035
Other plant and equipment (note 9)	**25,861**	27,550	27,096
Goodwill	**37,755**	37,755	37,755
	$ 2,432,318	$ 2,253,429	$ 1,935,632
LIABILITIES			
Current liabilities			
Trade and other payables (note 11)	**$ 233,062**	$ 183,314	$ 186,516
Dividends or distributions payable to shareholders/ unitholders	**23,035**	22,742	19,674
Bank loan (note 10)	**–**	–	265,088
Convertible debentures (note 13)	**–**	–	7,736
Financial derivatives (note 22)	**68,079**	20,312	12,004
	324,176	226,368	491,018
Non-current liabilities			
Bank loan (note 10)	**298,591**	303,773	–
Long-term debt (note 12)	**292,825**	146,893	146,498
Asset retirement obligations (note 14)	**173,262**	169,611	141,869
Unit-based payment liability (note 16)	**–**	–	91,559
Deferred income tax liability (note 18)	**253,589**	286,789	212,346
Financial derivatives (note 22)	**7,523**	8,859	1,418
	1,349,966	1,142,293	1,084,708
SHAREHOLDERS'/UNITHOLDERS' EQUITY			
Shareholders' capital (note 15)	**1,554,113**	1,484,335	–
Unitholders' capital (note 15)	**–**	–	1,331,161
Contributed surplus	**103,406**	129,129	–
Accumulated other comprehensive loss	**(15,321)**	(10,323)	–
Deficit	**(559,846)**	(492,005)	(480,237)
	1,082,352	1,111,136	850,924
	$ 2,432,318	$ 2,253,429	$ 1,935,632

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per common share and per trust unit amounts) (unaudited)	Three Months Ended March 31 2011	2010
Revenues, net of royalties (note 19)	$ 241,513	$ 210,817
Expenses		
Exploration and evaluation	3,466	5,846
Production and operating	47,476	42,234
Transportation and blending	64,160	52,039
General and administrative	11,130	11,131
Share-based or unit-based compensation (note 16)	7,982	31,914
Finance costs (note 20)	10,562	7,623
Loss (gain) on financial derivatives (note 22)	44,883	(12,386)
Foreign exchange gain (note 21)	(3,930)	(3,926)
Depletion and depreciation	56,644	47,881
	242,373	182,356
Net (loss) income before income taxes	(860)	28,461
Deferred income tax recovery (note 18)	(1,810)	(1,040)
Net income attributable to shareholders/unitholders	$ 950	$ 29,501
Other comprehensive loss		
Foreign currency translation adjustment	4,998	5,106
Comprehensive (loss) income	$ (4,048)	$ 24,395
Net income per share or trust unit (note 17)		
Basic	$ 0.01	$ 0.27
Diluted	$ 0.01	$ 0.26
Weighted average common shares or trust units (note 17)		
Basic	114,409	110,104
Diluted	117,661	112,192

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) (unaudited)	Unitholders' capital	Shareholders' capital	Contributed surplus	Accumulated other comprehensive loss	Deficit	Total equity
Balance at January 1, 2010	$ 1,331,161	$ –	$ –	$ –	$(480,237)	$ 850,924
Distributions to unitholders	–	–	–	–	(59,576)	(59,576)
Issued on conversion of debentures	3,092	–	–	–	–	3,092
Exercise of unit rights	28,749	–	–	–	–	28,749
Issued pursuant to distribution reinvestment plan	10,611	–	–	–	–	10,611
Net income for the period	–	–	–	–	29,501	29,501
Foreign currency translation	–	–	–	(5,106)	–	(5,106)
Balance at March 31, 2010	$ 1,373,613	$ –	$ –	$ (5,106)	$(510,312)	$ 858,195
Distributions to unitholders	–	–	–	–	(183,807)	(183,807)
Issued on conversion of debentures	16,805	–	–	–	–	16,805
Exercise of unit rights	53,900	–	–	–	–	53,900
Issued pursuant to distribution reinvestment plan	41,088	–	–	–	–	41,088
Net income for the period	–	–	–	–	202,114	202,114
Foreign currency translation	–	–	–	(5,217)	–	(5,217)
Change in effective tax rate on issuance costs	(1,071)	–	–	–	–	(1,071)
Exchange for shares, pursuant to the Arrangement	(1,484,335)	1,484,335	129,129	–	–	129,129
Balance at December 31, 2010	$ –	$ 1,484,335	$ 129,129	$ (10,323)	$(492,005)	$1,111,136
Dividends to shareholders	–	–	–	–	(68,791)	(68,791)
Exercise of share rights	–	53,336	(33,705)	–	–	19,631
Share-based compensation	–	–	7,982	–	–	7,982
Issued pursuant to dividend reinvestment plan	–	16,442	–	–	–	16,442
Net income for the period	–	–	–	–	950	950
Foreign currency translation	–	–	–	(4,998)	–	(4,998)
Balance at March 31, 2011	$ –	$ 1,554,113	$ 103,406	$ (15,321)	$(559,846)	$1,082,352

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31	
(thousands of Canadian dollars) (unaudited)	2011	2010
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income for the period	$ 950	$ 29,501
Adjustments for:		
Share-based or unit-based compensation (note 16)	7,982	31,914
Unrealized foreign exchange gain (note 21)	(4,856)	(4,850)
Exploration and evaluation (note 7)	2,484	4,493
Depletion and depreciation	56,644	47,881
Unrealized loss (gain) on financial derivatives (note 22)	46,470	(3,223)
Deferred income tax recovery (note 18)	(1,810)	(1,040)
Finance costs (note 20)	10,562	7,623
Change in non-cash working capital (note 21)	2,392	(9,633)
Asset retirement expenditures (note 14)	(919)	(611)
	119,899	102,055
Financing activities		
Payments of dividends or distributions	(52,057)	(48,722)
Decrease in bank loan	(1,077)	(2,144)
Proceeds from issuance of long-term debt (note 12)	145,810	–
Issuance of common shares or trust units (note 15)	19,631	9,373
Interest paid	(10,520)	(9,183)
	101,787	(50,676)
Investing activities		
Additions to exploration and evaluation assets (note 7)	(5,456)	(4,992)
Additions to oil and gas properties (note 8)	(81,558)	(50,364)
Property acquisitions (note 5)	(37,518)	(2,333)
Corporate acquisitions (note 5)	(117,346)	–
Additions other plant and equipment, net of disposals (note 9)	275	(4,839)
Change in non-cash working capital (note 21)	23,830	1,697
	(217,773)	(60,831)
Impact of foreign currency translation on cash balances	59	(97)
Change in cash	3,972	(9,549)
Cash, beginning of year	–	10,177
Cash, end of period	$ 3,972	$ 628

See accompanying notes to the condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at March 31, 2011 and for the three months ended March 31, 2011 and 2010

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

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is a Calgary, Alberta based 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 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

On December 31, 2010, Baytex Energy Trust (the "Trust") completed the conversion of its legal structure from an income trust to a corporation in connection with a Plan of Arrangement under the Business Corporations Act (Alberta) (the "Arrangement"). Pursuant to the Arrangement, the trust units of the Trust were exchanged for common shares of Baytex on a one-for-one basis. The reorganization into a corporation has been accounted for on a continuity of interest basis, and accordingly, the condensed consolidated financial statements reflect the financial position, results of operations and cash flows as if the Company had always carried on the business formerly carried on by the Trust.

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34, Interim Financial Reporting. Canadian generally accepted accounting principles ("previous GAAP") have been revised to incorporate International Financial Reporting Standards ("IFRS") and publicly accountable enterprises are required to apply such standards for years beginning on or after January 1, 2011. Accordingly, these condensed interim unaudited consolidated financial statements represent Baytex's initial presentation of its results and financial position under IFRS and were prepared in accordance with IFRS 1, First-time Adoption of IFRS. The significant accounting policies set out below were consistently applied to all the periods presented. These condensed interim unaudited consolidated financial statements do not include all the necessary annual disclosures in accordance with IFRS.

In these condensed interim unaudited consolidated financial statements, the term "previous GAAP" refers to Canadian generally accepted accounting principles prior to the adoption of IFRS. Previous GAAP differs in some areas from IFRS. In preparing these condensed interim unaudited consolidated financial statements, management has amended certain accounting, valuation and consolidation methods previously applied in the previous GAAP financial statements to comply with IFRS. The comparative figures for 2010 were restated to reflect these adjustments. The date of transition to IFRS was January 1, 2010. Reconciliations and descriptions of the effect of the transition from previous GAAP to IFRS on equity, net income and comprehensive income are included in note 23.

The condensed consolidated financial statements were approved and authorized by the Board of Directors on May 11, 2011.

The condensed consolidated financial statements have been prepared on the historical cost basis, except derivative financial instruments which have been measured at fair value. The condensed 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 or unit amounts and when otherwise indicated.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The condensed consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. The date of acquisition is the date on which the Company obtains control and the subsidiary companies continue to be consolidated until the date such control ceases. Control exists when the Company has the ability to direct the activities of an entity to generate returns from its activities. Inter-company transactions and balances are eliminated upon consolidation. A portion of the Company's exploration, development and production activities is conducted jointly with others and involve jointly controlled assets. These jointly controlled assets are accounted for using the proportionate consolidation method whereby the condensed consolidated financial statements reflect only the Company's proportionate interest.

Operating Segments Reporting

Baytex's operations are grouped into one operating segment for reporting consistent with the internal reporting provided to the chief operating decision-maker of the Company.

Measurement Uncertainty and Judgements

The preparation of the condensed consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the condensed consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depletion of oil and gas properties are based on a unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. The Company's total proved plus probable reserves are estimated annually using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent statistical probability of being recovered. Due to the inherent uncertainties and the necessarily limited nature of reservoir data, estimates of reserves are inherently imprecise, require the application of judgement and are subject to change as additional information becomes available. The impact of future changes to estimates on the condensed consolidated financial statements of subsequent periods could be material.

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

The Company's capital assets are aggregated into cash-generating units based on their ability to generate largely independent cash flows and are used for impairment testing. The definition of the Company's cash-generating units is subject to Management's judgement.

Impairment of assets and group of assets are based on the higher of calculations of value-in-use calculations and fair value less costs to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. The Company assesses internal and external indicators of impairment in determining whether the carrying values of the assets may not be recoverable.

Fair value of financial instruments, where active market quotes are not available are estimated using the Company's assessment of available market inputs and are described in note 22. These estimates may vary from the actual prices that will be achieved upon settlement of the financial instruments.

Fair values of share-based compensation are measured at the later of grant date or December 31, 2010, taking into consideration management's best estimate of the number of shares that will vest. Fair values of unit-based compensation were remeasured at each reporting date until the December 31, 2010 corporate conversion using a binomial-lattice pricing model, taking into consideration management's best estimate of the expected volatility, expected life of the option and estimated number of units that will vest.

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

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

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Business Combinations

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

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the reporting date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

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

a) Pre-license Costs

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

b) Exploration and Evaluation ("E&E") Costs

   Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well program/project is complete and the results have been evaluated. Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing. E&E costs are not depleted and are carried forward until technical feasibility and commercial viability of extracting a mineral resource is considered to be determined. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the impairment costs are charged to exploration and evaluation expense. Upon determination of proven and/or probable reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified to oil and gas properties.

c) Development Costs

   Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as oil and gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves and are accumulated on a geotechnical area basis.

Major maintenance and repairs consist of the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated and has been completely written off is replaced and it is probable that there are future economic benefits associated with the item, the expenditure is capitalized. The costs of the day-to-day servicing of property, plant and equipment are recognized in net income as incurred.

The carrying amount of any replaced or sold component of an oil and gas property is derecognized and included in net income in the period in which the item is derecognized.

d) Borrowing Costs and Other Capitalized Costs

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

No general and administrative expenses have been capitalized since Baytex's inception.

e) Depletion and Depreciation

The net carrying value of oil and gas properties is depleted using the units of production method using estimated proved and probable petroleum and natural gas reserves, by reference to the ratio of production in the year to the related proven and probable reserves at forecast prices, taking into account estimated future development costs necessary to bring those reserves into production. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil. Future development costs are estimated as the costs of development required to produce the reserves. These estimates are prepared by independent reserve engineers at least annually.

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

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

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

Impairment of Non-financial Assets

The goodwill balance is assessed for impairment at least annually at year end or more frequently if events or changes in circumstances indicate that the asset may be impaired. E&E assets are assessed for impairment when they are reclassified to oil and gas properties and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The Company assesses other assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable.

Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets (the "cash-generating unit" or

"CGU"). Goodwill acquired is allocated to CGUs expected to benefit from synergies of the related business combination.

If any such indication of impairment exists or when annual impairment testing for a CGU is required, the Company makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment amount reduces first the carrying amount of any goodwill allocated to the CGU. Any remaining impairment is allocated to the individual assets in the CGU on a pro rata basis. Impairment is charged to net income in the period in which it occurs.

For all assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depletion and depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in net income. After such a reversal, the depletion or depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life. Impairment losses recognized in relation to goodwill are not reversed for subsequent increases in its recoverable amount.

Asset Retirement Obligations

The Company recognizes a liability at the discounted value for the future asset retirement costs associated with its oil and gas properties using the risk-free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The discount in the liability unwinds until the date of expected settlement of the retirement obligations and is recognized as a finance cost in the statements of income and comprehensive income. The liability will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the statements of financial position.

Foreign Currency Translation

Transactions completed in foreign currencies are reflected in Canadian dollars at the foreign currency exchange rates prevailing at the time of the transactions. Monetary assets and liabilities denominated in foreign currencies are reflected in the statements of financial position at the Canadian equivalent at the foreign currency exchange rates prevailing at the reporting date. Foreign exchange gains and losses are included in net 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'/unitholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

Revenue Recognition

Revenue associated with sales of petroleum and natural gas is recognized when title passes to the purchaser at the pipeline delivery point. Revenue is measured net of discounts, customs duties and royalties. With respect to royalties, the Company is acting as a collection agent on behalf of the Crown and other royalty interest holders.

Revenue from the production of oil in which the Company has an interest with other producers is recognized based on the Company's working interest and the terms of the relevant joint venture agreements.

Financial Instruments

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

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets are measured at fair value and changes in fair value are recognized in net income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income (loss) until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

All risk management contracts are recorded in the statements of financial position at fair value unless they were entered into and continue to be held in accordance with the Company's expected purchase, sale and usage requirements. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net income. The Company has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net income.

Cash is classified as FVTPL. Trade and other receivables are classified as loans and receivables, which are measured at amortized cost. Trade and other payables and the bank loan are classified as other financial liabilities, which are measured at amortized cost.

The convertible debentures have been classified as liabilities, net of the fair value of the conversion feature which has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the instrument are recognized in the net income. The liability component is classified as other financial liabilities. The liability component will accrete up to the principal balance at maturity. The accretion and the interest paid are reported as finance expense in the condensed consolidated statements of income and comprehensive income (loss). If the debentures are converted to trust units, the fair value of the conversion feature will be reclassified to unitholders' capital along with the principal amounts converted.

An embedded derivative is a component of a contract that affects the terms of another factor. These hybrid contracts are considered to consist of a host contract plus an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative. The Company has no material embedded derivatives.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability classified at FVTPL are expensed immediately. For a financial asset or financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to or deducted from the fair value on initial recognition and amortized through net income over the term of the financial instrument.

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

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

Income Taxes

Current and deferred income taxes are recognized in net income, except when they relate to items that are recognized directly in equity. Where current and deferred income taxes are recognized directly in equity when current income tax or deferred income tax arises from the initial accounting for a business combination, the tax effect is included in the accounting for the business combination.

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

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

Share Rights Incentive Plan and Share Award Incentive Plan

The Trust's Trust Unit Rights Incentive Plan (the "Unit Rights Plan"), which was superseded by the Company's Common Share Rights Incentive Plan (the "Share Rights Plan"), is described in note 16. The exercise price of the share rights under the Share Rights Plan may be reduced in future periods in accordance with the terms of the Share Rights Plan.

Prior to the conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability was remeasured at each reporting date and at settlement date. Any changes in fair value were recognized in net income for the period. The conversion of the outstanding unit rights to share rights in connection with the Arrangement effectively changed the related classification from a liability plan to an equity-settled plan. The expense recognized from the date of modification over the remainder of the vesting period was determined based on the fair value of the reclassified equity awards at the date of the modification using a binomial-lattice pricing model.

Baytex's Share Award Incentive Plan (the "Share Award Plan") is described in note 16.

4. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Financial Instruments

In October 2010, IFRS 9, "Financial Instruments" was amended to introduce new requirements for the classification and measurement of financial assets and financial liabilities and for derecognition.

IFRS 9 requires all recognized financial assets that are within the scope of IAS 39 "Financial Instruments: Recognition and Measurement" to be subsequently measured at amortized cost or fair value. Specifically, debt investments that are held within a business model whose objective is to collect the contractual cash flows, and that have contractual cash flows that are solely payments of principal and interest on the principal outstanding are generally measured at amortized cost at the end of subsequent accounting periods. All other debt investments and equity investments are measured at their fair values at the end of subsequent accounting periods.

The most significant effect of IFRS 9 regarding the classification and measurement of financial liabilities relates to the accounting for changes in fair value of a financial liability (designated at FVTPL) attributable to changes in the credit risk of that liability. Specifically, under IFRS 9, for financial liabilities that are designated at FVTPL, the amount of change in the fair value of the financial liability that is attributable to changes in the credit risk of that liability is recognized as a gain or loss in other comprehensive income. Changes in fair value attributable to a financial liability's credit risk are not subsequently reclassified to net income. An exception to this is where the recognition of the effects of changes in the liability's credit risk in other comprehensive income would create or enlarge an accounting mismatch in net income, in which case all gains or losses would be presented in net income. Previously, under IAS 39, the entire amount of the change in the fair value of the financial liability designated at FVTPL was recognized as such.

IFRS 9 is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The adoption of this standard may have an impact on the Company's accounting for financial assets and financial liabilities.

Transfers of Financial Assets

The amendments to IFRS 7, "Financial Instruments: Disclosures" increase the disclosure requirements for transactions involving transfers of financial assets. These amendments are intended to provide greater transparency around risk exposures of transactions when a financial asset is transferred but the transferor retains some level of continuing exposure in the asset. The amendments also require disclosures where transfers of financial assets are not evenly distributed throughout the period. The IFRS 7 amendments are effective for annual periods beginning on or after July 1, 2011. The adoption of this amended standard may have an impact on the Company's disclosure if the Company enters into these types of transfers of financial assets in the future.

5. BUSINESS COMBINATIONS

2011 Corporate Acquisition

On February 3, 2011, Baytex Energy Ltd. ("Baytex Energy"), a wholly-owned subsidiary of Baytex, acquired all the issued and outstanding shares of a private company, which was a junior heavy oil producer with operational focus in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan, for total consideration of $118.3 million (net of cash acquired). The acquisition has been accounted for as a business combination with the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:	
Cash paid for plant, property and equipment	$ 117,346
Cash paid for working capital (net of cash acquired)	979
Total consideration	**$ 118,325**
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Trade and other receivables	$ 1,637
Exploration and evaluation assets	14,944
Oil and gas properties	127,850
Trade and other payables	(658)
Asset retirement obligations	(2,031)
Deferred income tax liability	(23,417)
Total net assets acquired	**$ 118,325**

For the period from February 3, 2011 to March 31, 2011, the acquired properties contributed revenue of $6.8 million to Baytex's operations. If the acquisition had occurred on January 1, 2011, management estimates that the acquired properties would have generated revenue of $9.9 million for the three month period ended March 31, 2011.

The values of assets and liabilities recognized are provisional due to the inherently uncertain nature of the oil and gas industry and intangible exploration evaluation assets in particular. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

2011 Property Acquisition

On February 3, 2011, Baytex Energy acquired heavy oil properties in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan, for total consideration of $37.1 million. The acquisition has been accounted for as a business combination with the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:	
Cash paid for plant, property and equipment	$ 37,063
Total consideration	**$ 37,063**
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Exploration and evaluation assets	$ 1,700
Oil and gas properties	35,871
Asset retirement obligations	(508)
Total net assets acquired	**$ 37,063**

For the period from February 3, 2011 to March 31, 2011, the acquired properties contributed revenue of $1.7 million to Baytex's operations. If the acquisition had occurred on January 1, 2011, management estimates that the acquired properties would have generated revenue of $2.5 million for the three month period ended March 31, 2011.

The values of assets and liabilities recognized are provisional due to the inherently uncertain nature of the oil and gas industry and intangible exploration evaluation assets in particular. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

2010 Corporate Acquisition

On May 26, 2010, Baytex Energy acquired all the issued and outstanding shares of a private company, which was a junior heavy oil producer with operational focus in the east central Alberta through to west central Saskatchewan, for total consideration of $40.3 million (net of cash acquired). The acquisition has been accounted for as a business combination with the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:	
Cash paid (net of cash acquired)	$ 40,314
Total consideration	**$ 40,314**
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Trade and other receivables	$ 1,722
Exploration and evaluation assets	2,534
Oil and gas properties	48,313
Trade and other payables	(1,436)
Asset retirement obligations	(2,207)
Deferred income tax liability	(8,612)
Total net assets acquired	**$ 40,314**

The values of assets and liabilities recognized are their estimated fair values at the acquisition date.

For the period from May 26, 2010 to December 31, 2010, the properties acquired from the private company contributed revenue of $8.7 million to Baytex's operations. If the acquisition had occurred on January 1, 2010, management estimates that the properties acquired from the private company would have generated revenue of $14.9 million for the year ended December 31, 2010.

The values of assets and liabilities recognized are provisional due to the inherently uncertain nature of the oil and gas industry and intangible exploration evaluation assets in particular. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

6. TRADE AND OTHER RECEIVABLES

As at	March 31, 2011	December 31, 2010	January 1, 2010
Petroleum and natural gas sales and accrual	$ 153,307	$ 119,827	$ 107,657
Joint venture	24,092	30,536	28,581
Prepaid, deposits and other	2,942	3,282	3,252
Allowance for doubtful accounts	(1,925)	(1,853)	(2,336)
	$ 178,416	$ 151,792	$ 137,154

7. EXPLORATION AND EVALUATION ASSETS

Cost	
As at January 1, 2010	**$ 124,621**
Capital expenditures	37,411
Corporate acquisition	2,534
Exploration and evaluation expense	(18,913)
Transfer to oil and gas properties	(29,116)
Divestitures	(113)
Foreign currency translation	(3,342)
As at December 31, 2010	**$ 113,082**
Capital expenditures	5,456
Corporate acquisition	14,944
Property acquisition	1,700
Exploration and evaluation expense	(2,484)
Transfer to oil and gas properties	(3,449)
Foreign currency translation	(1,297)
As at March 31, 2011	**$ 127,952**

8. OIL AND GAS PROPERTIES

Cost	
As at January 1, 2010	**$ 1,512,035**
Capital expenditures	218,651
Corporate acquisition	48,313
Transferred from exploration and evaluation assets	29,116
Change in asset retirement obligations	21,766
Divestitures	(4,072)
Foreign currency translation	(6,458)
As at December 31, 2010	**$ 1,819,351**
Capital expenditures	83,099
Corporate acquisition	127,850
Property acquisition	36,326
Transferred from exploration and evaluation assets	3,449
Change in asset retirement obligations	(973)
Foreign currency translation	(3,433)
As at March 31, 2011	**$ 2,065,669**

Accumulated depletion	
As at January 1, 2010	**$ –**
Depletion for the period	195,015
Divestitures	(107)
Foreign currency translation	(186)
As at December 31, 2010	**$ 194,722**
Depletion for the period	55,236
Foreign currency translation	(140)
As at March 31, 2011	**$ 249,818**

Carrying value	
As at January 1, 2010	**$ 1,512,035**
As at December 31, 2010	**$ 1,624,629**
As at March 31, 2011	**$ 1,815,851**

9. OTHER PLANT AND EQUIPMENT

Cost	
As at January 1, 2010	**$ 49,341**
Capital expenditures	8,473
Disposals	(236)
Foreign currency translation	(54)
As at December 31, 2010	**$ 57,524**
Capital expenditures	157
Disposals	(432)
Foreign currency translation	(25)
As at March 31, 2011	**$ 57,224**

Accumulated depreciation	
As at January 1, 2010	**$ 22,245**
Depreciation	7,781
Disposals	(26)
Foreign currency translation	(26)
As at December 31, 2010	**$ 29,974**
Depreciation	1,408
Foreign currency translation	(19)
As at March 31, 2011	**$ 31,363**

Carrying value	
As at January 1, 2010	**$ 27,096**
As at December 31, 2010	**$ 27,550**
As at March 31, 2011	**$ 25,861**

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

10. BANK LOAN

As at	**March 31, 2011**	December 31, 2010	January 1, 2010
Bank loan	**$ 298,591**	$ 303,773	$ 265,088

Baytex Energy has established credit facilities with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. On January 1, 2011, Baytex Energy reached agreement with its lending syndicate to increase the amount of the credit facilities to $625.0 million (from $550.0 million), to decrease its margins on advances based on the prime lending rate, bankers' acceptance rates or LIBOR rates and to decrease standby fees. The credit facilities were further increased to $650.0 million on February 17, 2011. In the event that the revolving period is not extended by June 2011, all amounts then outstanding under the credit facilities will be payable in June 2012. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates or LIBOR rates, plus applicable margins. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex Energy's assets. The weighted average interest rate on the bank loan for the three months ended March 31, 2011 was 3.84% (year ended December 31, 2010 – 4.60%, three months ended March 31, 2010 – 3.84%).

11. TRADE AND OTHER PAYABLES

As at	March 31, 2011	December 31, 2010	January 1, 2010
Trade payables	$ 116,349	$ 79,841	$ 79,150
Joint venture	17,206	12,284	14,924
Petroleum and natural gas accrued liabilities	88,505	77,656	75,471
Other	11,002	13,533	16,971
	$ 233,062	$ 183,314	$ 186,516

12. LONG-TERM DEBT

	March 31, 2011	December 31, 2010	January 1, 2010
9.15% senior unsecured debentures (Cdn$150,000 – principal)	$ 146,998	$ 146,893	$ 146,498
6.75% senior unsecured debentures (US$150,000 – principal)	145,827	–	–
	$ 292,825	$ 146,893	$ 146,498

On August 26, 2009, Baytex issued $150.0 million principal amount of Series A senior unsecured debentures bearing interest at 9.15% payable semi-annually with principal repayable on August 26, 2016. These debentures are subordinate to Baytex Energy's bank credit facilities. After August 26 of each of the following years, these debentures are redeemable at the Company's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2012 at 104.575%, 2013 at 103.05%, 2014 at 101.525%, and 2015 at 100%. These notes are carried at amortized cost, net of a $3.6 million transaction cost. The notes accrete up to the principal balance at maturity using the effective interest rate of 9.6%

On February 17, 2011 Baytex issued US$150.0 million principal amount of Series B senior unsecured debentures bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These debentures are subordinate to Baytex Energy's bank credit facilities. After February 17 of each of the following years, these debentures are redeemable at the Company's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2016 at 103.375%, 2017 at 102.25%, 2018 at 101.525%, and 2019 at 100%. These notes are carried at amortized cost, net of a $2.2 million transaction cost. These notes accrete up to the principal balance at maturity using the effective interest rate of 7.0%

Accretion expense on debentures of $0.1 million has been recorded for the three months ended March 31, 2011 (three months ended March 31, 2010 – $0.1 million).

13. CONVERTIBLE DEBENTURES

	Number of Convertible Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, January 1, 2010	7,815	$ 7,736	$ 7,354
Conversion	(7,474)	(7,426)	(12,473)
Accretion	–	31	–
Loss on financial derivative	–	–	5,119
Repayment on maturity	(341)	(341)	–
Balance, December 31, 2010 and March 31, 2011	**–**	**$ –**	**$ –**

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures paid interest semi-annually and were convertible at the option of the holder at any time into fully-paid trust units at a conversion price of $14.75 per trust unit. On the December 31, 2010 maturity date, the outstanding $0.3 million principal amount was repaid at par value.

The debentures were classified as debt net of the fair value of the conversion feature which was classified as a financial derivative liability. This resulted in $95.2 million being classified as a liability and $4.8 million being initially classified as a financial derivative liability. The debt portion accretes up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as a finance expense in the condensed consolidated statements of income and comprehensive income (loss). When debentures were converted to trust units, the fair value of the conversion feature under financial derivative liability was reclassified to unitholders' capital along with the principal amounts converted.

14. ASSET RETIREMENT OBLIGATIONS

	March 31, 2011	December 31, 2010
Balance, beginning of period	$ 169,611	$141,869
Liabilities incurred	1,559	2,030
Liabilities settled	(919)	(2,829)
Liabilities acquired	2,538	2,207
Liabilities divested	(18)	(1,254)
Accretion	1,484	5,862
Change in estimate[1]	(973)	21,766
Foreign currency translation	(20)	(40)
Balance, end of period	**$ 173,262**	$169,611

(1) Changes in the status of wells 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, 2011 is $298.0 million (December 31, 2010 – $288.8 million, January 1, 2010 – $279.3 million). The amount of estimated cash flow has been discounted at a risk free rate of 3.5% at March 31, 2011(December 31, 2010 – 3.5% and January 1, 2010 – 4.0%).

15. SHAREHOLDERS'/UNITHOLDERS' CAPITAL

Unitholders' Capital

	Number of Trust Units	Amount
Balance, January 1, 2010	**109,299**	**$ 1,331,161**
Issued on conversion of debentures	507	19,897
Issued on exercise of unit rights	2,337	26,021
Transfer from unit-based payment liability on exercise of unit rights	–	56,628
Issued pursuant to distribution reinvestment plan	1,569	51,699
Change in effective tax rate on issue costs	–	(1,071)
Exchanged for shares, pursuant to the Arrangement	(113,712)	(1,484,335)
Balance, December 31, 2010 and March 31, 2011	**–**	**$ –**

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, 2011, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares	Amount
Balance, January 1, 2010	**–**	**$ –**
Issued for units, pursuant to the Arrangement	113,712	1,484,335
Balance, December 31, 2010	**113,712**	**$ 1,484,335**
Issued on exercise of share rights	1,120	19,631
Transfer from contributed surplus on exercise of share rights	–	33,705
Issued pursuant to dividend reinvestment plan	345	16,442
Balance, March 31, 2011	**115,177**	**$ 1,554,113**

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

The holders of common shares or trust units may receive dividends or distributions as declared from time to time and are entitled to one vote per share or trust unit at any meetings of the holders of common shares or trust units. All common shares rank among themselves equally and with regard to the Company's net assets in the event of termination or winding-up of the Company.

Dividends of $0.20 per common share per month were declared by the Company during the three months ended March 31, 2011 for a total dividend declared of $68.8 million. Distributions of $0.20 per trust unit in December 2010 and $0.18 per trust unit for each of the previous eleven months were declared by the Trust during the year ended December 31, 2010 for a total distribution declared of $243.4 million.

Subsequent to March 31, 2011, dividends were declared by the Board of Directors in respect of April 2011 operations of $23.1 million or $0.20 per common share.

16. EQUITY BASED PLANS

Long Term Incentive Plan

The Trust had a Unit Rights Plan pursuant to which rights to acquire trust units ("unit rights") were granted to eligible directors, officers, employees and other service providers of the Trust and its subsidiaries. The maximum number of trust units issuable pursuant to the Unit Rights Plan was a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which were issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units resulted in an increase in the number of trust units available for issuance under the Unit Rights Plan, and any exercises of unit rights made new grants available under the Unit Rights Plan, effectively resulting in a re-loading of the number of unit rights available to grant under the Unit Rights Plan. Under the Unit Rights Plan, unit rights had 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.

The Unit Rights Plan provided that the exercise price of the unit rights may be reduced to account for future distributions, subject to certain performance criteria. Effective November 16, 2009, the Unit Rights Plan was amended to (i) base the exercise price of unit rights on the closing price of the trust units on the trading day prior to the date of grant (previously based on a five-day volume weighted average trading price) and (ii) permit the granting of unit rights with a fixed exercise price. Effective October 25, 2010, the Unit Rights Plan was amended to provide holders of unit rights who are not subject to taxation in the United States with the ability to elect at the time of exercise to pay an exercise price per unit right equal to (i) the original exercise price reduced for distributions paid subsequent to grant date or (ii) the original exercise price.

Pursuant to the terms of the Unit Rights Plan, the Arrangement (as described in note 1) constituted a capital reorganization which resulted in each holder of unit rights exchanging such rights for equivalent rights to acquire common shares of Baytex ("share rights") on a one-for-one basis on December 31, 2010. The share rights are subject to the terms of the Share Rights Plan. The Share Rights Plan is substantially similar to the Unit Rights Plan other than amendments necessary to reflect:

- The entitlement of holders to receive common shares instead of trust units;
- The exercise price, as calculated for unit rights outstanding at the effective time of the Arrangement, will be carried forward under the Share Rights Plan and, if applicable, future adjustments to the exercise price after the completion of the Arrangement will be based on dividends paid on the common shares of Baytex rather than distributions paid on the trust units of the Trust; and
- The administration of the Share Rights Plan will be carried out by Baytex as opposed to Baytex Energy.

As a result of the adoption of the Share Award Incentive Plan (as described below), no further grants will be made under the Share Rights Plan effective January 1, 2011.

Baytex recorded compensation expense of $5.3 million for the three months ended March 31, 2011 (three months ended March 31, 2010 – $31.9 million) related to the share rights or unit rights under the Share Rights Plan or Unit Rights Plan.

Baytex uses a binomial-lattice pricing model to calculate the estimated weighted average fair value of the share rights and unit rights. The following assumptions were used to arrive at the estimate of fair values at each reporting date, with the expense recognized from the December 31, 2010 date of modification over the remainder of the vesting period determined based on the fair value of the reclassified unit rights at the date of the modification:

	As at December 31, 2010	As at January 1, 2010
Expected annual exercise price reduction (on unit rights or share rights with declining exercise price)	Various	$ 2.16
Share or unit price	$ 46.61	$ 29.70
Expected volatility(1)	43.8%	43.4%
Risk-free interest rate	1.99%	2.57%
Expected life of share right or unit right(2)	Various	Various
Forfeiture rate	4.6%	4.6%

(1) Expected volatility is estimated by considering the historical average price volatility of the common shares/trust units commensurate with the term of the right.

(2) The binomial-lattice model pricing calculates the fair values based on an optimal strategy, resulting in various expected life of share rights or unit rights.

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

	Number of share or unit rights	Weighted average exercise price[1]
Balance, January 1, 2010	8,120	$ 16.68
Granted[2]	190	32.71
Exercised	(2,337)	11.13
Forfeited	(212)	20.35
Balance, December 31, 2010	**5,761**	**$ 17.02**
Granted	–	–
Exercised	(1,120)	17.54
Forfeited	(32)	19.86
Balance, March 31, 2011	**4,609**	**$ 17.34**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price.
(2) Weighted average exercise price of rights granted is based on the exercise price at the date of grant.

The following table summarizes information about the share rights outstanding at March 31, 2011:

	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, 2011**	Weighted Average Grant Price	Weighted Average Remaining Term *(years)*	**Number Exercisable at March 31, 2011**	Weighted Average Exercise Price	**Number Outstanding at March 31, 2011**	Weighted Average Exercise Price	Weighted Average Remaining Term *(years)*	**Number Exercisable at March 31, 2011**	Weighted Average Exercise Price
$8.68 to $15.00	71	$ 14.33	2.8	46	$ 14.40	2,840	$ 12.93	1.9	2,161	$ 12.87
$15.01 to $21.50	2,670	18.68	2.1	1,875	19.02	384	18.66	2.7	143	18.84
$21.51 to $28.00	1,636	26.13	3.0	730	24.99	1,255	25.30	3.7	380	25.22
$28.01 to $34.50	183	30.12	3.6	46	28.92	93	30.92	4.0	13	28.73
$34.51 to $41.00	46	37.43	4.5	–	–	34	37.74	4.5	–	–
$41.01 to $47.72	3	44.96	4.7	–	–	3	44.43	4.7	–	–
$8.68 to $47.72	4,609	$ 21.91	2.5	2,697	$ 20.72	4,609	$ 17.34	2.5	2,697	$ 15.00

Share Award Incentive Plan

In connection with the Arrangement, the unitholders of the Trust approved, at a special meeting held on December 9, 2010, the adoption by the Company effective January 1, 2011 of a full-value award plan (the Share Award Plan) pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plan of the Company, including the Share Rights Plan) shall not at any time exceed 10% of the then issued and outstanding common shares.

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

On January 11, 2011, the Compensation Committee of the Board of Directors of Baytex approved the initial awards under the Share Award Incentive Plan. An aggregate of 227,400 performance awards and 356,200 restricted awards, with 50% to be granted effective January 18, 2011 and the remaining 50% to be granted effective in July 2011, were awarded to eligible directors, officers and employees of the Company and its subsidiaries. The grants effective July 2011 are conditional on the grantee continuing to be employed with the Company or its subsidiaries.

The Company recorded compensation expense of $2.7 million for the three months ended March 31, 2011 related to the share awards ($nil for the three months ended March 31, 2010).

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 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 is $46.50 per restricted award and $76.26 per performance award issued during the three months ended March 31, 2011 (no share awards were issued during the three months ended March 31, 2010).

The number of share awards outstanding is detailed below:

	Number of share awards
Balance, January 1, 2010 and December 31, 2010	–
Granted	291,800
Forfeited	(1,800)
Balance, March 31, 2011	**290,000**

17. NET INCOME PER SHARE AND PER TRUST UNIT

Baytex calculates basic income per share and per trust unit based on the net income attributable to shareholders or unitholders and a weighted average number of shares or units outstanding during the period. Diluted income per share or trust unit amounts reflect the potential dilution that could occur if share rights or unit rights were exercised, share awards were converted and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of share rights or unit rights whereby any proceeds from the exercise of share rights or unit 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 share or trust units at the average market price during the periods.

	Three Months Ended March 31, 2011			Three Months Ended March 31, 2010		
	Net income	Common Shares	Net income per share	Net income	Trust units	Net income per unit
Net income per basic share or unit	$ 950	114,409	$ 0.01	$ 29,501	110,104	$ 0.27
Dilutive effect of share rights or unit rights	–	3,182		–	1,592	
Dilutive effect of share awards	–	70		–	–	
Conversion of convertible debentures	–	–		96	496	
Net income per diluted share or unit	$ 950	117,661	$ 0.01	$ 29,597	112,192	$ 0.26

For the three months ended March 31, 2011, 14,750 share rights (three months ended March 31, 2010 – 2.0 million unit rights) were excluded in calculating the weighted average number of diluted common shares outstanding as they were anti-dilutive.

18. INCOME TAXES

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

	Three Months Ended March 31	
	2011	2010
Net (loss) income before income taxes	$ (860)	$ 28,461
Expected income taxes at the statutory rate of 26.98% (2010 – 28.49%)	(232)	8,109
Increase (decrease) in income taxes resulting from:		
Net income of the Trust prior to the Arrangement	–	(16,130)
Non-taxable portion of foreign exchange gain	(655)	(795)
Non-deductible items	33	727
Effect of change in income tax rate	(2,686)	(2,884)
Effect of change in opening tax pool balances	(356)	–
Effect of change in valuation allowance	–	797
Share-based or unit-based compensation	2,153	9,092
Other	(67)	44
Deferred income tax recovery	$ (1,810)	$ (1,040)

The components of the net deferred income tax liability are as follows:

As at	March 31, 2011	December 31, 2010	January 1, 2010
Deferred income tax liabilities:			
Petroleum and natural gas properties	$ (248,714)	$ (224,923)	$ (196,118)
Financial derivatives	(4,655)	(4,463)	(9,432)
Partnership deferral	–	(52,327)	(2,921)
Other	(220)	(5,076)	(3,875)
Deferred income tax assets:			
Asset retirement obligations	44,285	43,339	36,446
Financial derivatives	20,397	7,870	1,789
Non-capital losses	158,972	227,149	13,185
Finance costs	1,602	1,918	1,996
Net deferred income tax liability(1)	$ (28,333)	$ (6,513)	$ (158,930)

(1) Non-capital loss carry-forwards totaled $595.9 million (December 31, 2010 – $842.3 million, January 1, 2010 – $48.4 million) and expire from 2014 to 2031.

In May 2010, Baytex acquired a number of private entities for use in its internal financing structure for approximately $38.0 million. The transaction resulted in the recognition of a future income tax asset of approximately $147.8 million with a corresponding deferred credit of $109.8 million recognized under previous GAAP. Under IFRS, the deferred credit is derecognized through net income as a deferred income tax recovery. This reflects the difference between the future tax asset recognized upon the completion of this transaction and the cash paid.

19. REVENUES

	Three Months Ended March 31	
	2011	2010
Petroleum and natural gas revenues	$ 289,793	$ 261,321
Royalty charges	(48,802)	(50,965)
Royalty income	522	461
Total revenues, net of royalties	$ 241,513	$ 210,817

20. FINANCE COSTS

Baytex incurred finance costs on its outstanding liabilities as follows:

	Three Months Ended March 31	
	2011	2010
Bank loan and other	$ 3,721	$ 2,621
Long-term debt	4,696	3,411
Accretion on asset retirement obligation	1,484	1,419
Convertible debentures	–	135
Financing charges	661	37
Finance costs	$ 10,562	$ 7,623

21. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Three Months Ended March 31	
	2011	2010
Trade and other receivables	$ (27,467)	$ (22,474)
Crude oil inventory	1,802	466
Trade and other payables	51,618	14,236
Foreign exchange	269	(164)
	$ 26,222	$ (7,936)
Changes in non-cash working capital related to:		
Operating activities	$ 2,392	$ (9,633)
Investing activities	23,830	1,697
	$ 26,222	$ (7,936)

Foreign Exchange

	Three Months Ended March 31	
	2011	2010
Unrealized foreign exchange gain	$ (4,856)	$ (4,850)
Realized foreign exchange loss	926	924
Foreign exchange gain	$ (3,930)	$ (3,926)

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan and long-term debt, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its carrying value as it is at a market rate of interest. The fair value of the long-term debt is based on the lower of trading value and the present value of future cash flows associated with the debentures.

Fair Value of Financial Instruments

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

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

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

	March 31, 2011		December 31, 2010		January 1, 2010		
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value	Fair Value Measurement Hierarchy
Financial Assets							
FVTPL							
Cash	$ 3,972	$ 3,972	$ –	$ –	$ 10,177	$ 10,177	Level 1
Derivatives	17,255	17,255	16,543	16,543	31,994	31,994	Level 2
Total FVTPL	$ 21,227	$ 21,227	$ 16,543	$ 16,543	$ 42,171	$ 42,171	
Loans and receivables							
Trade and other receivables	$ 178,416	$ 178,416	$ 151,792	$ 151,792	$ 137,154	$ 137,154	–
Total loans and receivables	$ 178,416	$ 178,416	$ 151,792	$ 151,792	$ 137,154	$ 137,154	
Financial Liabilities							
FVTPL							
Derivatives	$ (75,602)	$ (75,602)	$ (29,171)	$ (29,171)	$ (13,422)	$ (13,422)	Level 2
Total FVTPL	$ (75,602)	$ (75,602)	$ (29,171)	$ (29,171)	$ (13,422)	$ (13,422)	
Other financial liabilities							
Trade and other payables	$ (233,062)	$ (233,062)	$ (183,314)	$ (183,314)	$ (186,516)	$ (186,516)	–
Dividends or distributions payable to shareholders or unitholders	(23,035)	(23,035)	(22,742)	(22,742)	(19,674)	(19,674)	–
Bank loan	(298,591)	(298,591)	(303,773)	(303,773)	(265,088)	(265,088)	–
Convertible debentures	–	–	–	–	(7,736)	(7,736)	–
Long-term debt	(292,825)	(312,769)	(146,893)	(163,875)	(146,498)	(162,750)	Level 1
Total other financial liabilities	$ (847,513)	$ (867,457)	$ (656,722)	$ (673,704)	$ (625,512)	$ (641,764)	

Financial Risk

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

Market Risk

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

Foreign currency risk

Baytex is exposed to fluctuations in foreign currency as a result of the U.S. dollar portion of its bank loan, its Series B senior unsecured debenture, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Company's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of currency exchange rate fluctuations, the Company may enter into agreements to fix the Canada – U.S. exchange rate.

At March 31, 2011, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price[(1)]
Forward sales	January 1, 2010 to December 31, 2011	US$5.0 million	1.0711
Forward sales	June 1, 2010 to June 30, 2012	US$1.0 million	1.0250
Forward sales	January 1, 2011 to December 31, 2011	US$3.0 million	1.0677
Forward sales	January 1, 2011 to June 30, 2012	US$3.0 million	1.0622
Forward sales	January 1, 2011 to August 31, 2012	US$1.0 million	1.0565
Forward sales	January 1, 2011 to September 30, 2012	US$1.5 million	1.0553
Forward sales	April 1, 2011 to June 30, 2011	US$1.0 million	0.9903
Forward sales	July 1, 2011 to September 30, 2011	US$1.0 million	0.9918
Forward sales	October 1, 2011 to December 31, 2011	US$2.0 million	0.9911
Forward sales	November 1, 2011 to October, 2013	US$1.0 million	1.0433
Forward sales	January 1, 2012 to March 31, 2012	US$2.0 million	0.9936
Forward sales	April 1, 2012 to June 30, 2012	US$2.0 million	0.9958
Forward sales	July 1, 2012 to September 30, 2012	US$2.0 million	0.9982
Forward sales	October 1, 2012 to December 31, 2012	US$2.0 million	0.9997
Forward sales	January 1, 2013 to March 31, 2013	US$2.0 million	1.0015
Forward sales	April 1, 2013 to June 30, 2013	US$2.0 million	1.0024
Forward sales	July 1, 2013 to September 30, 2013	US$2.0 million	1.0028
Forward sales	October 1, 2013 to December 31, 2013	US$2.0 million	1.0033

(1) Based on the weighted average exchange rate (CAD/USD).

The following table demonstrates the effect of movements in the Canada – United States exchange rate on net income before income taxes and comprehensive income due to changes in the fair value of the currency swaps as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at March 31, 2011.

	$0.01 Increase (Decrease) in CAD/USD Exchange Rate
Loss (gain) on currency forward sales agreements	$2,467
Loss (gain) on other monetary assets/liabilities	3,757
Impact on net income before income taxes and comprehensive income	$6,224

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, 2011	December 31, 2010	January 1, 2010	March 31, 2011	December 31, 2010	January 1, 2010
U.S. dollar denominated	US$ 75,209	US$ 72,663	US$ 67,389	US$ 433,395	US$ 230,878	US$ 198,690

Interest rate risk

The Company's interest rate risk arises from its floating rate bank credit facilities. As at March 31, 2011, $298.6 million of the Company's total debt is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income before taxes for the three months ended March 31, 2011 by approximately $0.8 million. Baytex uses a combination of short-term and long-term debt to finance operations. The bank loan is typically at floating rates of interest and long-term debt is typically at fixed rates of interest.

At March 31, 2011, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay floating, receive fixed	September 23, 2009 to August 26, 2011	Cdn$150.0 million	9.15%	3-month BA plus 7.875%
Swap – pay fixed, receive floating	September 27, 2011 to September 27, 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, received floating	September 25, 2012 to September 25, 2014	US$90.0 million	4.39%	3-month LIBOR

When assessing the potential impact of forward interest rate changes on financial derivative contracts outstanding as at March 31, 2011, an increase or decrease of 100 basis points would result in an increase or decrease, respectively, to the unrealized loss in three months ended March 31, 2011 by approximately $2.1 million.

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.

When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at March 31, 2011, a 10% increase would increase the unrealized loss at March 31, 2011 by $42.6 million, while a 10% decrease would decrease the unrealized loss at March 31, 2011 by $41.3 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at March 31, 2011, a 10% increase would increase the unrealized loss at March 31, 2011 by $2.0 million, while a 10% decrease would decrease the unrealized loss at March 31, 2011 by $1.8 million.

Financial Derivative Contracts

At March 31, 2011, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Fixed – Sell	January to June 2011	500 bbl/d	US$91.69	WTI
Fixed – Sell	February 2011 to December 2012	500 bbl/d	US$98.33	WTI
Fixed – Sell	March to December 2011	500 bbl/d	US$95.10	WTI
Fixed – Sell	March to December 2011	500 bbl/d	US$96.24	WTI
Fixed – Sell	March to December 2011	500 bbl/d	US$100.76	WTI
Fixed – Sell	March to December 2011	250 bbl/d	US$102.28	WTI
Fixed – Sell	March to December 2011	250 bbl/d	US$104.40	WTI
Price collar	March to December 2011	250 bbl/d	US$95.00 - 107.20	WTI
Price collar	March to December 2011	200 bbl/d	US$100.00 - 112.60	WTI
Time spread	March to December 2011	500 bbl/d	Dec 2013 plus US$1.40	WTI
Price collar	April to December 2011	100 bbl/d	US$100.00 - 117.00	WTI
Price collar	July to December 2011	500 bbl/d	US$90.00 - 95.00	WTI
Time spread	July 2011	2,500 bbl/d	Dec 2013 less US$2.75	WTI
Time spread	August 2011	2,500 bbl/d	Dec 2013 less US$2.31	WTI
Fixed – Sell	Calendar 2011	1,000 bbl/d	US$85.79	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$86,60	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$85.40	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$85.40	WTI
Fixed – Sell	Calendar 2011	1,500 bbl/d	US$86.60	WTI
Fixed – Sell	Calendar 2011	1,000 bbl/d	US$87.15	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$90.05	WTI
Fixed – Sell	Calendar 2011	300 bbl/d	US$94.45	WTI
Fixed – Sell	Calendar 2011	200 bbl/d	US$93.20	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$90.75	WTI
Fixed – Sell	Calendar 2011	200 bbl/d	US$94.30	WTI
Price collar	Calendar 2011	500 bbl/d	US$85.00 - 90.00	WTI
Price collar	Calendar 2011	500 bbl/d	US$85.00 - 92.50	WTI
Price collar	Calendar 2011	500 bbl/d	US$87.50 - 92.00	WTI
Price collar	Calendar 2011	500 bbl/d	US$89.00 - 92.20	WTI
Price collar	Calendar 2011	500 bbl/d	US$89.00 - 92.30	WTI
Price collar	Calendar 2011	1,000 bbl/d	US$90.00 - 98.00	WTI
Price collar	Calendar 2011	300 bbl/d	US$91.00 - 97.60	WTI
Price collar	Calendar 2011	200 bbl/d	US$91.50 - 94.85	WTI
Price collar	Calendar 2011	200 bbl/d	US$92.50 - 96.65	WTI
Fixed – Sell	Calendar 2011	1,000 bbl/d	WTI $\times$ 82.00%	WCS

Natural Gas	Period	Volume	Price/Unit	Index
Fixed – Sell	March to June 2011	3,000 mmBtu/d	US$4.71	NYMEX
Sold call	July to December 2011	3,000 mmBtu/d	US$6.25	NYMEX
Sold call	July to December 2011	3,000 mmBtu/d	US$5.00	NYMEX
Fixed – Sell	July to December 2011	2,500 mmBtu/d	US$4.50	NYMEX
Fixed – Sell	July to December 2011	2,500 mmBtu/d	US$4.62	NYMEX
Fixed – Sell	July to December 2011	1,000 mmBtu/d	US$4.90	NYMEX
Basis swap	Calendar 2011	4,000 mmBtu/d	NYMEX less US$0.615	AECO
Basis swap	Calendar 2011	2,000 mmBtu/d	NYMEX less US$0.490	AECO
Sold call	Calendar 2012	6,000 mmBtu/d	US$5.25	NYMEX

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	
	2011	2010
Realized gain on financial derivatives	$ (1,587)	$ (9,163)
Unrealized loss (gain) on financial derivatives	46,470	(3,223)
Loss (gain) on financial derivatives	$ 44,883	$ (12,386)

Included in unrealized loss (gain) on financial derivatives is a loss of $2.6 million relating to the conversion feature of the convertible debentures for the three months ended March 31, 2010 ($nil for the three months ended March 31, 2011), (see note 13).

Subsequent to March 31, 2011, Baytex added the following financial derivative contracts:

Natural Gas	Period	Volume	Price/Unit	Index
Fixed – Sell	Calendar 2012	1,500 mmBtu/d	US$5.02	NYMEX
Fixed – Sell	Calendar 2012	1,500 mmBtu/d	US$5.02	NYMEX
Fixed – Sell	Calendar 2012	1,000 mmBtu/d	US$5.18	NYMEX

Physical Delivery Contracts

At March 31, 2011, 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 financial statements.

Heavy Oil	Period	Volume	Weighted Average Price/Unit
LLK Blend	June to August 2011	2,000 bbl/d	WTI less US$14.75
WCS Blend	June to August 2011	500 bbl/d	WTI less US$15.50
WCS Blend	April to June 2011	2,000 bbl/d	WTI less US$15.80
WCS Blend	April to December 2011	2,000 bbl/d	WTI × 80.25%
WCS Blend	April to September 2011	1,000 bbl/d	WTI less US$16.00
WCS Blend	June to August 2011	1,000 bbl/d	WTI less US$17.00
WCS Blend	July to September 2011	2,000 bbl/d	WTI less US$15.60
LLB Blend	January to March 2011	2,000 bbl/d	WTI less US$15.00
LLB Blend	January to September 2011	1,000 bbl/d	WTI less US$15.25
WCS Blend	Calendar 2011	2,000 bbl/d	WTI less US$15.38
WCS Blend	Calendar 2011	1,000 bbl/d	WTI less US$16.00
WCS Blend	Calendar 2011	500 bbl/d	WTI less US$16.00
WCS Blend	Calendar 2011	1,000 bbl/d	WTI × 82.00%
WCS Blend	Calendar 2011	1,000 bbl/d	WTI × 82.90%
WCS Blend	Calendar 2012	2,000 bbl/d	WTI less US$16.50
WCS Blend	Calendar 2012	2,000 bbl/d	WTI less US$19.75
WCS Blend	January to June 2013	1,250 bbl/d	WTI × 80.00%
WCS Blend	January to June 2013	1,250 bbl/d	WTI less US$21.00
WCS Blend	January to June 2013	3,000 bbl/d	WTI less US$17.00
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

Natural Gas	Period	Volume	Price/Unit
Fixed – Sell	February to November 2011	2,500 GJ/d	AECO Cdn$5.03
Price collar	Calendar 2011	2,500 GJ/d	AECO Cdn$5.50 - 7.10
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.80
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.71
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$5.00
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.82
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.88

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include continuously monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements and opportunities to issue additional common shares. As at March 31, 2011, Baytex had available unused bank credit facilities in the amount of $351.4 million.

The timing of cash outflows (excluding interest) relating to financial liabilities is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$233,062**	$233,062	$ –	$ –	$ –
Dividends payable to shareholders	**23,035**	23,035	–	–	–
Bank loan(1)	**298,591**	–	298,591	–	–
Long-term debt(2)	**295,770**	–	–	–	295,770
	$850,458	$256,097	$298,591	$ –	$295,770

(1) The bank loan is a 364-day revolving loan with a one year term-out following the 364-day revolving period with the ability to extend the term. Unless extended, the revolving period will end on June 27, 2011 with all amounts to be re-paid by June 27, 2012.

(2) Principal amount of instruments.

Credit Risk

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

Should Baytex determine that the ultimate collection of a receivable is in doubt based on the processes for managing credit risk, the carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income. If the Company subsequently determines that an account is uncollectible, the account is written-off with a corresponding change to allowance for doubtful accounts.

23. FIRST-TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

For all periods up to and including the year ended December 31, 2010, the Company prepared its financial statements in accordance with previous GAAP. The Accounting Standards Board confirmed that IFRS will replace previous GAAP for financial periods beginning January 1, 2011 with restatement required for comparative purposes of amounts reported for year ended December 31, 2010, including the opening statement of financial position as at January 1, 2010. These financial statements for the three months ended March 31, 2011, comprise the Company's first condensed consolidated financial statements prepared under IFRS.

The Company has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2011 and the significant accounting policies meeting those requirements are described in note 3.

The general principle that should be applied on first-time adoption of IFRS is that standards in force at the first reporting date should be applied retrospectively. However, IFRS 1, "First-Time Adoption of International Financial

Reporting Standards", provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas. The Company has taken the following optional exemptions:

- IFRS 2, "Share-based Payment", has not been applied to any liabilities arising from share-based payment transactions that settled before January 1, 2010.
- Deemed costs of oil and gas assets are based on exploration and evaluation assets at the amount determined under previous GAAP and assets in the development or production phases at the amount determined for the cost centre under previous GAAP, allocated to the cost centres' underlying assets pro rata using reserve values as of January 1, 2010.
- IFRS Interpretations Committee ("IFRIC") 1, "Determining whether an Arrangement contains a Lease", transition rules have been applied that allow determination of whether any existing arrangement at January 1, 2010 contains a lease on the basis of the facts and circumstances existing at that date.
- IFRS 3, "Business Combinations", has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010, the Company's date of transition.
- Cumulative translation differences are deemed to be $nil at January 1, 2010 and deficit adjusted by the same amount.
- Asset retirement liabilities included in the cost of property, plant and equipment are measured as at January 1, 2010 in accordance with IAS 37, "Provisions, Contingent Liabilities and Contingent Assets", and the difference between that amount and the carrying amount of those liabilities at January 1, 2010 determined under previous GAAP are recognized directly in deficit.
- IAS 23, "Borrowing Costs", transition rules have been applied that allow application of the standard to borrowing costs related to qualifying assets for which the commencement date for capitalization is on or after the effective date, January 1, 2010.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME – IFRS

(thousands of Canadian dollars, except per common share and per trust unit amounts) (unaudited)	Note	Twelve Months Ended December 31, 2010 Previous GAAP	Effect of transition to IFRS	IFRS	Three Months Ended March 31, 2010 Previous GAAP	Effect of transition to IFRS	IFRS
Revenues							
Petroleum and natural gas	N	$1,005,136	$(170,844)	$ 834,292	$ 261,782	$ (50,965)	$210,817
Royalties	F,N	(162,332)	162,332	–	(47,348)	47,348	–
Gain on financial derivatives		9,935	(9,935)	–	14,937	(14,937)	–
		852,739	(18,447)	834,292	229,371	(18,554)	210,817
Expenses							
Exploration and evaluation	B	–	24,502	24,502	–	5,846	5,846
Production and operating		171,740	(54)	171,686	42,296	(62)	42,234
Transportation and blending		188,591	–	188,591	52,039	–	52,039
General and administrative		39,774	973	40,747	11,131	–	11,131
Unit-based compensation	J	8,344	85,855	94,199	2,454	29,460	31,914
Finance costs	H, I	32,828	1,742	34,570	7,201	422	7,623
Gain on oil and gas properties	C	–	(16,209)	(16,209)	–	–	–
Gain on financial derivatives	G	–	(4,817)	(4,817)	–	(12,386)	(12,386)
Foreign exchange gain		(9,148)	–	(9,148)	(3,926)	–	(3,926)
Depletion and depreciation	D	266,527	(63,731)	202,796	64,926	(17,045)	47,881
		698,656	28,261	726,917	176,121	6,235	182,356
Net income before income taxes		154,083	(46,708)	107,375	53,250	(24,789)	28,461
Income tax expense (recovery)							
Current	F	8,512	(8,512)	–	3,617	(3,617)	–
Deferred	M	(32,060)	(92,180)	(124,240)	(2,321)	1,281	(1,040)
		(23,548)	(100,692)	(124,240)	1,296	(2,336)	(1,040)
Net income attributable to shareholders/unitholders		$ 177,631	$ 53,984	$ 231,615	$ 51,954	$ (22,453)	$ 29,501
Other comprehensive loss							
Foreign currency translation adjustment		10,708	(385)	10,323	5,144	(38)	5,106
Comprehensive income		$ 166,923	$ 54,369	$ 221,292	$ 46,810	$ (22,415)	$ 24,395

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION – IFRS

		December 31, 2010			March 31, 2010			January 1, 2010		
(thousands of Canadian dollars) (unaudited)	Note	Previous GAAP	Effect of transition to IFRS	IFRS	Previous GAAP	Effect of transition to IFRS	IFRS	Previous GAAP	Effect of transition to IFRS	IFRS
Assets										
Current assets										
Cash	O	$ –	$ –	$ –	$ 628	$ –	$ 628	$ 10,177	$ –	$ 10,177
Trade and other receivables	A	151,792	–	151,792	159,628	–	159,628	137,154	–	137,154
Crude oil inventory		1,802	–	1,802	918	–	918	1,384	–	1,384
Future income tax asset	A,M	5,480	(5,480)	–	1,944	(1,944)	–	1,371	(1,371)	–
Financial derivatives		13,921	–	13,921	37,691	–	37,691	29,453	–	29,453
		172,995	(5,480)	167,515	200,809	(1,944)	198,865	179,539	(1,371)	178,168
Non-current assets										
Deferred income tax asset	A,M	150,190	130,086	280,276	874	52,222	53,096	418	52,998	53,416
Financial derivatives		2,622	–	2,622	3,163	–	3,163	2,541	–	2,541
Exploration and evaluation assets	B	–	113,082	113,082	–	117,547	117,547	–	124,621	124,621
Oil and gas properties	A,C,D,I	1,683,650	(59,021)	1,624,629	1,658,561	(136,071)	1,522,490	1,663,752	(151,717)	1,512,035
Other plant and equipment	E	–	27,550	27,550	–	30,277	30,277	–	27,096	27,096
Goodwill		37,755	–	37,755	37,755	–	37,755	37,755	–	37,755
		$2,047,212	$ 206,217	$2,253,429	$1,901,162	$ 62,031	$1,963,193	$1,884,005	$ 51,627	$1,935,632
Liabilities										
Current liabilities										
Trade and other payables	A	$ 179,269	$ 4,045	$ 183,314	$ 191,638	$ 6,024	$ 197,662	$ 180,493	$ 6,023	$ 186,516
Distributions payable to unitholders		22,742	–	22,742	19,917	–	19,917	19,674	–	19,674
Bank loan		–	–	–	257,364	–	257,364	265,088	–	265,088
Convertible debentures		–	–	–	6,353	–	6,353	7,736	–	7,736
Future income tax liability	A,M	3,756	(3,756)	–	10,742	(10,742)	–	8,683	(8,683)	–
Financial derivatives	G	20,312	–	20,312	6,820	8,211	15,031	4,650	7,354	12,004
		226,079	289	226,368	492,834	3,493	496,327	486,324	4,694	491,018
Non-current liabilities										
Bank loan		303,773	–	303,773	–	–	–	–		–
Long-term debt	H	150,000	(3,107)	146,893	150,000	(3,406)	146,594	150,000	(3,502)	146,498
Deferred credit	L	109,800	(109,800)	–	–	–	–	–	–	–
Asset retirement obligations	I	52,373	117,238	169,611	55,870	88,055	143,925	54,593	87,276	141,869
Unit-based payment liability	J	–	–	–	–	104,097	104,097	–	91,559	91,559
Deferred income tax liability	A,M	167,302	119,487	286,789	176,325	34,665	210,990	179,673	32,673	212,346
Financial derivatives		8,859	–	8,859	3,065	–	3,065	1,418	–	1,418
		1,018,186	124,107	1,142,293	878,094	226,904	1,104,998	872,008	212,700	1,084,708
Shareholders'/ Unitholders' Equity										
Shareholders' capital	J	1,390,034	94,301	1,484,335	–	–	–	–	–	–
Unitholders' capital	G,J	–	–	–	1,320,672	52,941	1,373,613	1,295,931	35,230	1,331,161
Conversion feature of convertible debentures	G	–	–	–	307	(307)	–	374	(374)	–
Contributed surplus	J	20,131	108,998	129,129	19,534	(19,534)	–	20,371	(20,371)	–
Accumulated other comprehensive loss	K	(14,607)	4,284	(10,323)	(9,043)	3,937	(5,106)	(3,899)	3,899	–
Deficit		(366,532)	(125,473)	(492,005)	(308,402)	(201,910)	(510,312)	(300,780)	(179,457)	(480,237)
		1,029,026	82,110	1,111,136	1,023,068	(164,873)	858,195	1,011,997	(161,073)	850,924
		$2,047,212	$ 206,217	$2,253,429	$1,901,162	$ 62,031	$1,963,193	$1,884,005	$ 51,627	$1,935,632

A) Presentation Differences

Certain presentation differences between previous GAAP and IFRS have no impact on reported net income or total equity.

Some line items are described differently (renamed) under IFRS compared to previous GAAP. These line items are as follows (with previous GAAP descriptions in brackets):

- Trade and other receivables (Accounts receivable)
- Oil and gas properties (Petroleum and natural gas properties)
- Deferred income tax asset/liability (Future income tax asset/liability)
- Trade and other payables (Accounts payable and accrued liabilities)

B) Exploration and Evaluation

Under previous GAAP, petroleum and natural gas properties included certain exploration and evaluation expenditures incurred within a country-by-country cost centre. Under IFRS, such exploration and evaluation expenditures are recognized as tangible or intangible based on their nature and subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are expensed.

Exploration and evaluation assets at January 1, 2010 were deemed to be $124.6 million, being the amount recorded as the undeveloped land balance under previous GAAP. This has resulted in the reclassification from property, plant and equipment to intangible exploration assets of $124.6 million in the opening IFRS statement of financial position.

During the year ended December 31, 2010, Baytex transferred exploration and evaluation expense of $29.1 million to oil and gas properties and expensed $18.9 million of exploration and evaluation assets related to lease expiries and $5.6 million in direct exploration costs. For the three months ended March 31, 2010, Baytex transferred exploration and evaluation expense of $7.2 million to oil and gas properties and expensed $4.5 million of exploration and evaluation assets related to lease expiries and $1.3 million in direct exploration costs.

C) Oil and Gas Properties

IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. The Company has allocated the amount recognized under previous GAAP as at January 1, 2010 using reserve values to the assets at an area level. This has resulted in the reclassification from property, plant and equipment to oil and gas properties of $1,512.0 million in the opening IFRS statement of financial position.

Previous GAAP utilized full cost accounting whereby gains and losses were not recognized upon the divestiture of oil and gas assets unless such a divestiture would alter the rate of depletion by 20% or more. Under IFRS, gains and losses are recognized based on the difference between the net proceeds from the divestiture and the carrying value of the asset disposed. For the year ended December 31, 2010, a gain of $16.2 million was recognized relating to a divestiture of oil and gas assets.

D) Depletion

Upon transition to IFRS, the Company adopted a policy of depleting oil and gas properties on a "units of production" basis over proved plus probable reserves at a more componentized area basis than under previous GAAP. The depletion policy under previous GAAP was units of production over proved reserves on a country basis.

There is no impact to depletion on transition of IFRS at January 1, 2010. For the year ended December 31, 2010, this resulted in a decrease in depletion expense of $67.4 million with a corresponding increase in oil and gas properties (three months ended March 31, 2010 – decrease in depletion of $17.9 million).

E) Other Plant and Equipment

Contains amounts previously grouped within petroleum and natural gas properties for plant and equipment unrelated to oil and gas properties.

F) Current Income Tax Expense

Under previous GAAP, Saskatchewan resource surcharge expense was classified as current income tax. Under IFRS, Saskatchewan resource surcharge is considered a royalty and is netted against petroleum and natural gas revenues. Saskatchewan resource surcharge for the twelve months ended December 31, 2010 netted in revenues is $8.5 million (three months ended March 31, 2010 – $3.6 million).

G) Conversion Feature of Convertible Debentures

Under previous GAAP, the convertible debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' or shareholders' equity. The debt portion accreted up to the principal balance at maturity. If the debentures were converted to trust units, a portion of the value of the conversion feature under unitholders' equity was reclassified to unitholders' capital along with principal amounts converted.

Under IFRS, the conversion feature of the convertible debentures has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the derivative liability are recognized in the statements of income and comprehensive income. If the debentures were converted to trust units, the fair value of the conversion feature under financial derivative liability was reclassified to unitholders'/shareholders' capital along with the principal amounts converted. The impact on adoption to IFRS at January 1, 2010 was an additional liability of $7.4 million, an increase of $33.4 million in unitholders' capital with a corresponding $40.4 million charge to deficit and a decrease of $0.4 million in the conversion feature of convertible debentures.

Under IFRS, for the year ended December 31, 2010, the increase in unitholders'/shareholders' equity of $12.1 million and the increase of $0.4 million in conversion feature of convertible debentures had a corresponding decrease in the $7.4 million liability recorded at January 1, 2010 and a $5.1 million decrease in gain on financial derivatives in net income.

H) Long-term Debt

Under previous GAAP, the Company's policy was to immediately expense transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability. Under IFRS, the transaction costs for financial instruments carried at amortized cost are included in the calculation of the effective interest rate and effectively amortized through net income over the term of the instrument. Baytex's $150.0 million principal amount of Series A senior unsecured debentures are classified as other financial liabilities. Under IFRS, the senior unsecured debentures are carried at amortized cost, net of the associated $3.6 million transaction costs, which will accrete up to the principal balance at maturity using the effective interest rate. Under IFRS, a reduction in the long-term debt liability of $3.5 million had a corresponding decrease in deficit at January 1, 2010. Accretion expense included in finance costs for the year ended December 31, 2010 is $0.4 million.

I) Asset Retirement Obligations

Under IFRS, Baytex uses a risk-free interest rate to discount the estimated fair value of its asset retirement obligations associated with the related oil and gas properties. Under previous GAAP, the Company used a credit-adjusted interest rate. A lower discount rate under IFRS increases the asset retirement obligations. In addition, under IFRS the asset retirement obligations are measured using the best estimate of the expenditures to be incurred and uses current discount rates at each remeasurement date with the corresponding adjustment to the cost of the related oil and gas properties. Existing liabilities under previous GAAP are not remeasured using current discount rates.

Under previous GAAP, the Company's asset retirement obligations were recorded using the credit-adjusted risk free rate of 8.0%. Under IFRS, the Company's asset retirement obligations are recorded using the risk free rate of 3.5%

at December 31, 2010 (4.0% at January 1, 2010). Under IFRS, an additional liability of $87.3 million was charged to deficit at January 1, 2010. At December 31, 2010, excluding the January 1, 2010 adjustment, the lower discount rates used resulted in an additional liability of $29.9 million and a resulting $28.6 million increase to the related oil and gas properties.

For the twelve months ended December 31, 2010, the $4.5 million accretion expense on asset retirement obligations under previous GAAP was reclassified to finance costs and an additional accretion expense on asset retirement obligations of $1.3 million has been recognized in net income under IFRS (three months ended March 31, 2010 – $1.1 million reclassified and an additional accretion expense of $0.3 million).

J) Unit-based Compensation

Under previous GAAP, the obligation associated with the Unit Rights Plan is considered to be equity-based and the related unit-based compensation was calculated using the binomial-lattice model to estimate the fair value of the outstanding unit rights at grant date. The exercise of unit rights was recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Under IFRS, prior to the conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability is remeasured at each reporting date and at settlement date. Any changes in fair value are recognized in net income for the period. For periods prior to the conversion to a corporation remeasuring the fair value of the obligation each reporting period will increase or decrease the unit-based payment liability, unitholders' capital and compensation expense recognized. Upon conversion to a corporation, the outstanding Unit Rights Plan was modified to become the new Share Rights Plan, effectively changing the related classification from liability-settled to equity-settled. The expense recognized from the date of the plan modification over the remainder of the vesting period is determined based on the fair value of the reclassified unit rights at the date of the modification. Upon transition of IFRS at January 1, 2010, an additional unit-based payment liability of $91.6 million and a decrease of $20.4 million in contributed surplus had a corresponding $71.2 million charge to deficit.

Under IFRS, in addition to the January 1, 2010 adjustments discussed above, at December 31, 2010 the remeasurement of the liability at reporting date and at settlement date resulted in an additional unit-based compensation expense of $85.9 million recognized, with a corresponding decrease of $0.3 million in contributed surplus, an increase of $48.0 million in shareholders'/unitholders' equity and an increase of $37.6 million in unit-based payment liability. At December 31, 2010, the $129.1 million balance in unit-based payment liability was transferred to contributed surplus in conjunction with the corporate conversion.

K) Accumulated Other Comprehensive Loss

Under previous GAAP, amounts are composed entirely of currency translation adjustments on self-sustaining foreign operations. Under IFRS, the Company has elected to deem cumulative currency translation differences as $nil at January 1, 2010. At January 1, 2010, this has resulted in a decrease in accumulated other comprehensive loss with a corresponding increase in deficit of $3.9 million.

L) Deferred Credit

Baytex acquired several private entities to be used in its internal financing structure. Under previous GAAP, the excess of amounts assigned to the acquired assets over the consideration paid is classified as a deferred credit. Under IFRS, the deferred credit is derecognized through net income as a deferred income tax recovery. For the year ended December 31, 2010, a deferred income tax recovery of $109.8 million was recorded in net income for amounts previously recognized as a deferred credit.

M) Deferred Income Taxes

Under IFRS, deferred income taxes are required to be presented as non-current. Upon transition to IFRS, the Company recognized a $27.6 million reduction in the net deferred income tax liability entirely resulting from the tax impact of the adjustments from previous GAAP to IFRS with a decrease to deficit of $25.8 million and a decrease to unitholders' capital of $1.8 million.

For the year ended December 31, 2010, the application of the IFRS adjustments resulted in a $92.2 million increase to the Company's deferred income tax recovery. Under IFRS, taxable and deductible temporary differences related to the legal entity of the Trust must be measured using the highest marginal personal tax rate of 39%, as opposed to the corporate tax rates used under previous GAAP, resulting in an increase to the deferred income tax asset of $5.1 million at January 1, 2010. Upon conversion to a dividend paying corporation on December 31, 2010, the total deferred income tax asset related to the Trust was adjusted to the corporate tax rate of approximately 25% and derecognized through net income on December 31, 2010.

N) Royalties

Under previous GAAP, gross petroleum and natural gas revenues and royalties were presented separately. Under IFRS, petroleum and natural gas revenues are presented net of crown, third-party, gross overriding royalties and production taxes.

O) Statements of Cash Flows

The transition from previous GAAP to IFRS had no material effect on the reported cash flows generated by the Company.

ABBREVIATIONS

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

* *BOEs 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.

John A. Brussa (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

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

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

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

Anthony W. Marino
President & Chief Executive Officer
Baytex Energy Corp.

Gregory K. Melchin (1)
Independent Businessman

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

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

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Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

OFFICERS

Raymond T. Chan
Executive Chairman

Anthony W. Marino
President & Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Exploration

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

Brett J. McDonald
Vice President, Land

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

R. Shaun Paterson
Vice President, Marketing

Richard P. Ramsay
Vice President, Heavy Oil

Mark F. Smith
Vice President, Conventional Oil & Gas

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