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 year ended December 31, 2011. This information is provided as of March 13, 2012. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2011 and 2010 (the "consolidated financial statements"), together with accompanying notes, and the Annual Information Form for the year ended December 31, 2011. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. The consolidated financial statements for the year ended December 31, 2011 are 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 consolidated 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.

2011 OVERVIEW

We are a conventional oil and gas corporation with our head office in Calgary, Alberta. Through our subsidiaries, we are engaged in the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets in Canada (primarily in the provinces of British Columbia, Alberta and Saskatchewan) and in the United States (primarily in the states of North Dakota and Wyoming). We act as the primary financing vehicle for our subsidiaries by providing access to debt and equity capital markets.

During 2011, we executed a successful capital program, resulting in the replacement of 156% of production (on a proved plus probable basis) by reinvesting approximately 66% of funds from operations into exploration and development activities. Including acquisitions (net of proceeds of disposition), our capital program replaced 227% of production while reinvesting approximately 93% of funds from operations.

On February 3, 2011, we completed the acquisition of heavy oil assets located in the Reno area of northern Alberta and the Lloydminster area of western Saskatchewan. The total consideration for the acquisition of $159.3 million (net of adjustments) was funded by drawing on our revolving credit facilities.

On February 17, 2011, we completed a private placement of US$150 million principal amount of 6.75% Series B senior unsecured debentures due February 17, 2021. The net proceeds of the offering were used to repay existing indebtedness under the credit facilities and for general corporate purposes.

On August 9, 2011, we completed the acquisition of natural gas assets located in the Brewster area of west central Alberta. The total consideration for the acquisition of $22.4 million (net of adjustments) was funded by drawing on our revolving credit facilities.

In the fourth quarter of 2011, we completed two dispositions of primarily undeveloped lands for $47.4 million. In the Kaybob South area of west central Alberta, we sold six sections of leasehold, including five sections with Duvernay rights, for $11.1 million. In the Dodsland area in southwest Saskatchewan, we sold 32,600 net acres of leasehold in the "halo" of the field for $36.3 million.

As at December 31, 2011, our total proved reserves increased 12% to 157 million boe and our total proved plus probable reserves increased 10% to 252 million boe. During the year ended December 31, 2011, our production averaged 50,132 boe/d, primarily from our properties in Canada.

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 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 the officers and directors remained the same. Baytex's activities are directed towards increasing oil production through organic property development and acquisitions, with the objectives of providing monthly income and long-term value creation for its 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. Baytex will also seek to acquire undeveloped and producing petroleum and natural gas properties. Baytex will primarily participate in development activities that are 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 have received 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

In this MD&A, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Funds from Operations

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

Payout Ratio

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

Total Monetary Debt

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

Operating Netback

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

RESULTS OF OPERATIONS

Production

	Years Ended December 31		
	2011	2010	Change
Daily Production			
Light oil and NGL (bbl/d)	**6,769**	6,539	4%
Heavy oil (bbl/d)[(1)]	**35,252**	28,585	23%
Natural gas (mmcf/d)	**48.7**	55.3	(12%)
Total production (boe/d)	**50,132**	44,341	13%
Production Mix			
Light oil and NGL	**14%**	15%	–
Heavy oil	**70%**	64%	–
Natural gas	**16%**	21%	–

(1) *Heavy oil sales volumes may differ from reported production volumes due to changes to Baytex's heavy oil inventory. For the year ended December 31, 2011, heavy oil sales volumes were 72 bbl/d higher than production volumes (year ended December 31, 2010 – 36 bbl/d lower).*

Production for the year ended December 31, 2011 averaged 50,132 boe/d, as compared to 44,341 boe/d for the same period in 2010. Light oil and NGL production for the year ended December 31, 2011 increased by 4% to 6,769 bbl/d from 6,539 bbl/d a year earlier due to development activities in the US, which increased US production by 81%, as compared to the same period in 2010, partially offset by second quarter production interruptions in North Dakota, Alberta and British Columbia. Heavy oil production for the year ended December 31, 2011 increased by 23% to 35,252 bbl/d from 28,585 bbl/d a year ago primarily due to development activities and the acquisition of producing assets in the first quarter of 2011. Natural gas production decreased by 12% to 48.7 mmcf/d for the year ended December 31, 2011, as compared to 55.3 mmcf/d for the same period. The decrease in natural gas production was primarily due to natural declines as we focused our drilling effort on our oil portfolio and, to a lesser extent, to pipeline constraints in west central Alberta partially offset by a natural gas-weighted acquisition that closed in the third quarter of 2011.

Commodity Prices

Crude Oil

For the year ended December 31, 2011, the price of West Texas Intermediate ("WTI") fluctuated from a low of US$75.67/bbl to a high of US$113.93/bbl. The average prompt WTI price for the year ended December 31, 2011 was US$95.12/bbl, or 20% higher than the corresponding 2010 price of US$79.53/bbl. 2011 was a year of significant volatility, as oil prices reacted to rapidly changing macroeconomic issues and uncertainty, political and social unrest, and underlying energy market fundamentals. Global oil demand growth from emerging market countries, including China, and several smaller oil supply disruptions, have helped support oil prices over the past year. By the end of 2011, oil markets appeared to focus on signs of improving economic activity in the United States and growing tensions over Iran's nuclear program, both of which contributing to rising oil prices.

The Western Canadian Select ("WCS") price differential to WTI, averaged 18% in the year ended December 31, 2011, unchanged from 2010. The volatility of the heavy oil differential in 2011 was marked by periodic transportation disruptions increasing differentials, which was offset by a combination of high refinery runs in the mid-continent region of the United States and new heavy oil refinery capacity in late 2011 supporting heavy oil demand and lower heavy oil differentials.

Natural Gas

For the year ended December 31, 2011, AECO natural gas prices averaged $3.68/mcf, as compared to $4.13/mcf in 2010. Natural gas prices have remained at depressed levels during 2011 due to significant natural gas production capacity additions in the United States, which have exceeded gas demand growth, and a warm start to the winter of 2011-2012 resulting in low demand.

	Years Ended December 31		
	2011	2010	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	$ 95.12	$ 79.53	20%
WCS heavy oil (US$/bbl)[2]	$ 77.97	$ 65.30	19%
Heavy oil differential[3]	(18%)	(18%)	–%
USD/CAD average exchange rate	1.0114	0.9708	4%
Edmonton par oil ($/bbl)	$ 95.56	$ 77.81	23%
AECO natural gas price ($/mcf)[4]	$ 3.68	$ 4.13	(11%)
Baytex Average Sales Prices			
Light oil and NGL ($/bbl)	$ 82.49	$ 65.90	25%
Heavy oil ($/bbl)[5]	$ 65.36	$ 60.08	9%
Physical forward sales contracts gain (loss) ($/bbl)	0.17	(0.68)	
Heavy oil, net ($/bbl)	$ 65.53	$ 59.40	10%
Total oil and NGL, net ($/bbl)	$ 68.26	$ 60.61	13%
Natural gas ($/mcf)[6]	$ 3.86	$ 4.22	(9%)
Physical forward sales contracts gain ($/mcf)	0.31	0.10	
Natural gas, net ($/mcf)	$ 4.17	$ 4.32	(3%)
Summary			
Weighted average ($/boe)[6]	$ 60.78	$ 53.75	13%
Physical forward sales contracts gain (loss) ($/boe)	0.48	(0.36)	
Weighted average, net ($/boe)	$ 61.26	$ 53.39	15%

(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 above pricing information in the table excludes the impact of financial derivatives.

For the year ended December 31, 2011, Baytex's average sales price for light oil and NGL was $82.49/bbl, up 25% from $65.90/bbl in the same period in 2010. Baytex's realized heavy oil price during the year ended December 31, 2011, prior to physical forward sales contracts, was $65.36/bbl, or 85% of WCS. This compares to a realized heavy oil price in the same period of 2010, prior to physical forward sales contracts, of $60.08/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 year ended December 31, 2011 was $65.53/bbl, up 10% from $59.40/bbl in the same period in 2010. Baytex's realized natural gas price for the year ended December 31, 2011 was $3.86/mcf prior to physical forward sales contracts and $4.17/mcf inclusive of physical forward sales contracts (year ended December 31, 2010 – $4.22/mcf prior to physical forward sales contracts and $4.32/mcf inclusive of physical forward sales contracts).

Gross Revenues

	Years Ended December 31		
($ thousands except for %)	**2011**	2010	Change
Oil revenue			
Light oil and NGL	**$ 204,513**	$ 157,603	30%
Heavy oil	**843,707**	618,969	36%
Total oil revenue	**1,048,220**	776,572	35%
Natural gas revenue	**74,018**	87,116	(15%)
Total oil and natural gas revenue	**1,122,238**	863,688	30%
Sales of heavy oil blending diluent	**186,576**	141,448	32%
Total petroleum and natural gas sales	**$ 1,308,814**	$ 1,005,136	30%

For the year ended December 31, 2011, petroleum and natural gas sales increased 30% to $1,308.8 million from $1,005.1 million for the same period in 2010. During this period, the change was driven by heavy oil revenues which increased by 36% due to a 9% increase in realized price and an 23% increase in sales volume compared to the year ended December 31, 2010.

Royalties

	Years Ended December 31		
($ thousands except for % and per boe)	**2011**	2010	Change
Royalties	**$ 212,172**	$ 170,844	24%
Royalty rates:			
Light oil, NGL and natural gas	**18.7%**	20.5%	–
Heavy oil	**19.0%**	19.5%	–
Average royalty rates[1]	**18.9%**	19.8%	–
Royalty expenses per boe	**$ 11.59**	$ 10.56	10%

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

Total royalties for the year ended December 31, 2011 increased to $212.2 million from $170.8 million in the year ended December 31, 2010. Total royalties for the year ended December 31, 2011 were 18.9% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 19.8% for the same period in 2010. Royalty rates for light oil, NGL and natural gas decreased from 20.5% in the year ended December 31, 2010 to 18.7% in the year ended December 31, 2011 due to conventional oil royalty rate incentives on new wells, partially offset by higher royalty rates for properties acquired in August 2011. Royalty rates for heavy oil decreased from 19.5% in the year ended December 31, 2010 to 19.0% in the year ended December 31, 2011 due to royalty rate incentives on new wells at Seal and Kerrobert. In addition, Baytex received a positive $1.0 million Alberta Royalty Tax Credit reassessment related to 2004 and 2005 periods. This increased credit was received in the first quarter of 2011, which decreased our reported royalty rate for 2011.

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

	Years Ended December 31		
($ thousands)	2011	2010	Change
Realized gain (loss) on financial derivatives[1]			
Crude oil	$ (17,641)	$ 7,609	$ (25,250)
Natural gas	431	11,322	(10,891)
Foreign currency	15,230	28,119	(12,889)
Interest rate	116	1,079	(963)
Total	$ (1,864)	$ 48,129	$ (49,993)
Unrealized gain (loss) on financial derivatives[2]			
Crude oil	$ 1,237	$ (17,546)	$ 18,783
Natural gas	6,004	(641)	6,645
Foreign currency	(17,542)	(9,261)	(8,281)
Interest rate	(5,865)	(15,864)	9,999
Total	$ (16,166)	$ (43,312)	$ 27,146
Total gain (loss) on financial derivatives			
Crude oil	$ (16,404)	$ (9,937)	$ (6,467)
Natural gas	6,435	10,681	(4,246)
Foreign currency	(2,312)	18,858	(21,170)
Interest rate	(5,749)	(14,785)	9,036
Total	$ (18,030)	$ 4,817	$ (22,847)

(1) Realized gain (loss) on financial derivatives represents actual cash settlement or receipts under 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 year ended December 31, 2011 was $18.0 million, as compared to a gain of $4.8 million for the same period in 2010. This includes a realized loss of $1.9 million and an unrealized mark-to-market loss of $16.2 million for the year ended December 31, 2011, as compared to $48.1 million in realized gains and $43.3 million in unrealized losses for the same period in 2010. The realized loss of $1.9 million for the year ended December 31, 2011 relates to the realization of losses on commodity contracts due to higher oil prices offset by gains on foreign currency contracts. The unrealized loss of $16.2 million for the year ended December 31, 2011, is mainly due to the reversal of previously recorded unrealized gains on foreign currency contracts as they are settled upon maturity and a decrease in floating 3-month London Interbank Offer Rates offset by lower natural gas price.

A summary of the risk management contracts in place as at December 31, 2011 and the accounting treatment of the Company's financial instruments are disclosed in note 23 to the consolidated financial statements as at and for the year ended December 31, 2011.

Evaluation and Exploration Expense

Evaluation and exploration expense for the year ended December 31, 2011 decreased to $13.9 million, as compared and $24.5 million for the year ended December 31, 2010, due to a decrease in the expiration of undeveloped land leases during 2011.

Production and Operating Expenses

($ thousands except for % and per boe)	Years Ended December 31 2011	2010	Change
Production and operating expenses	$ 209,177	$ 171,704	22%
Production and operating expenses per boe	$ 11.43	$ 10.62	8%

Production and operating expenses for the year ended December 31, 2011 increased to $209.2 million from $171.7 million for the same period of 2010 due to an increase in total production volumes from development activities and difficult weather conditions. In the winter months, Baytex experienced increased costs for energy inputs and snow removal. In the spring months, Baytex experienced increased costs due to forest fires in northern Alberta and extremely wet ground conditions in North Dakota. In the summer months, production and operating expenses increased due to the increased cost of energy inputs and a number of turnarounds conducted at operated and non-operated oil and natural gas processing facilities. Production and operating expenses were $11.43 per boe for the year ended December 31, 2011, as compared to $10.62 per boe for the same period in 2010. For the year ended December 31, 2011, production and operating expenses were $12.21 per boe of light oil, NGL and natural gas and $11.09 per barrel of heavy oil, as compared to $10.64 per boe and $10.60 per barrel, respectively, for the same period in 2010.

Transportation and Blending Expenses

($ thousands except for % and per boe)	Years Ended December 31 2011	2010	Change
Blending expenses	$ 186,576	$ 141,448	32%
Transportation expenses(1)	63,274	47,143	34%
Total transportation and blending expenses	$ 249,850	$ 188,591	32%
Transportation expense per boe(1)	$ 3.46	$ 2.92	18%

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

Transportation and blending expenses for the year ended December 31, 2011 were $249.9 million, as compared to $188.6 million for the year ended 2010.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. In most cases, Baytex purchases condensate from industry producers as the blending diluent to facilitate the marketing of its heavy oil. In the year ended December 31, 2011, blending expenses were $186.6 million for the purchase of 5,031 bbl/d of condensate at $101.60 per barrel, as compared to $141.4 million for the purchase of 4,557 bbl/d at $85.05 per barrel for the same period last year. The cost of blending diluent is effectively recovered in the sale price of a blended product.

Transportation expenses were $3.46 per boe for the year ended December 31, 2011, as compared to $2.92 per boe for the same period of 2010. Transportation expenses were $0.79 per boe of light oil, NGL and natural gas and $4.58 per barrel of heavy oil in the year ended December 31, 2011, as compared to $0.85 and $4.05 per barrel, respectively, for the same period in 2010. The increase in transportation expenses per barrel of heavy oil is primarily due to a larger portion of our heavy oil production coming from Seal, which utilizes long-haul trucking to ship a portion of production volumes, and higher fuel prices.

Operating Netback

($ per boe except for % and volume)	Years Ended December 31 2011	2010	Change
Sales volume (boe/d)	**50,154**	44,305	13%
Operating netback(1):			
Sales price(2)	$ **61.26**	$ 53.39	15%
Less:			
Royalties	**11.59**	10.56	10%
Operating expenses	**11.43**	10.62	8%
Transportation expenses	**3.46**	2.92	18%
Operating netback before financial derivatives	$ **34.78**	$ 29.29	19%
Financial derivatives gain (loss)(3)	**(0.10)**	2.98	(103%)
Operating netback after financial derivatives gain (loss)	$ **34.68**	$ 32.27	7%

(1) Operating netback table includes revenues and costs associated with sulphur production.
(2) Sales price is shown net of blending costs and gains (losses) on physical delivery contracts.
(3) Financial derivatives reflect realized gains (losses) only.

General and Administrative Expenses

($ thousands except for % and per boe)	Years Ended December 31 2011	2010	Change
General and administrative expenses	$ **39,335**	$ 40,747	(3%)
General and administrative expenses per boe	$ **2.15**	$ 2.52	(15%)

General and administrative expenses for the year ended December 31, 2011 decreased to $39.3 million from $40.7 million for the year ended December 31, 2010. This decrease is a result of lower non-recurring consulting fees, including fees relating to our corporate conversion at year-end 2010, and higher capital overhead recoveries from increased capital expenditures, partially offset by increases in rent and independent reserves evaluator fees.

Share-based Compensation Expense

Compensation expense related to the Common Share Rights Incentive Plan (the “Share Rights Plan”) was $15.6 million for the year ended December 31, 2011, as compared to a $94.2 million expense related to the Trust Unit Rights Incentive Plan of the Trust (the “Unit Rights Plan”) for the same period in 2010. The significant decrease in compensation expense is primarily due to the change in classification of the plans. Under IFRS, prior to our conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability is re-measured at each reporting date and at settlement date. Any changes in fair value are recognized in net income for the period. 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.

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 year ended December 31, 2011, the Company recorded $18.2 million related to the share awards (December 31, 2010 – $nil). This increase is the result of the compensation expense related to share awards granted in 2011.

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

Financing Costs

	Years Ended December 31		
($ thousands except for %)	2011	2010	Change
Bank loan and other	$ 12,489	$ 12,547	–%
Long-term debt	22,935	14,198	62%
Accretion on asset retirement obligations	6,185	5,862	6%
Convertible debentures	–	320	(100%)
Debt financing costs	3,002	1,643	83%
Financing costs	$ 44,611	$ 34,570	29%

Financing costs for the year ended December 31, 2011 increased to $44.6 million, as compared to $34.6 million for the year ended December 31, 2010. The increase in financing costs was primarily attributable to the higher levels of outstanding debt, interest on the US$150.0 million principal amount of 6.75% Series B senior unsecured debentures issued on February 17, 2011 and higher fees for our revolving credit facilities.

Foreign Exchange

	Years Ended December 31		
($ thousands except for % and exchange rates)	2011	2010	Change
Unrealized foreign exchange loss (gain)	$ 8,490	$ (8,999)	194%
Realized foreign exchange gain	(656)	(149)	(340%)
Total loss (gain)	$ 7,834	$ (9,148)	186%
USD/CAD exchange rates:			
At beginning of period	1.0054	0.9555	
At end of period	0.9833	1.0054	

The foreign exchange loss for the year ended December 31, 2011 was $7.8 million, as compared to a gain of $9.1 million for the year ended December 31, 2010. This loss was comprised of an unrealized foreign exchange loss of $8.5 million and a realized foreign exchange gain of $0.7 million. The year ended December 31, 2011 unrealized loss of $8.5 million, as compared to a gain of $9.0 million for the same period in 2010, was due to the translation of the US$180.0 million portion of the bank loan as the USD/CAD foreign exchange rates strengthened (as compared to December 31, 2010) and weakened at December 31, 2010 (as compared to December 31, 2009). In addition, the translation of the US$150.0 million Series B senior unsecured debentures issued on February 17, 2011 contributed to the year-to-date unrealized foreign exchange loss as the USD/CAD foreign exchange rate strengthened from the issue date of the debentures to December 31, 2011. The realized gains for the year ended December 31, 2011 and 2010 were due to day-to-day US dollar denominated transactions.

Depletion and Depreciation

Depletion and depreciation for the year ended December 31, 2011 increased to $248.5 million from $202.8 million for the same period in 2010. On a sales-unit basis, the provision for the year ended December 31, 2011 was $13.57 per boe, as compared to $12.54 per boe for the same period in 2010 due to the increase in future development costs resulting in a higher depletable base.

Income Taxes

For the year ended December 31, 2011, deferred income tax expense totaled $52.1 million, as compared to a recovery of $124.2 million for the year ended December 31, 2010. Prior to its conversion from a mutual fund trust to a corporation on December 31, 2010, Baytex sheltered a portion of its income from income taxes by deducting distributions payable to unitholders. Subsequent to conversion, the Company's earnings have been entirely sheltered from current income taxes by a drawdown of tax pools. An increase in deferred income tax expense in 2011 compared to 2010 reflects the cost of consuming these pools. In addition, $109.8 million of the $124.2 million recovery for the year ended December 31, 2010 recovery for the year ended December 31, 2011 relates to the difference between the deferred income tax asset and the cash paid for the acquisition of private entities during the second quarter of 2010.

As at December 31, 2011, net deferred income tax liability was $83.1 million (December 31, 2010 – $6.5 million). The increase relates to the additional liability recognized in the corporate acquisition in the current year of $24.5 million and the impact of accounting income net of adjustments due to decrease in rates and adjustments to opening tax pool balances.

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 was payable by the Trust, other than the Saskatchewan resource surcharge which is classified as a royalty expense under IFRS.

As a result of the conversion from a trust structure to a corporate legal form on December 31, 2010, Baytex is no longer 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 the future. We have accumulated the Canadian and US 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 existing legislation, we expect to become liable for Canadian income taxes in 2013.

The income tax pools detailed below are deductible at various rates as prescribed by law:

($ thousands)	**December 31, 2011**	December 31, 2010
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 264,503**	$ 271,741
Canadian development expenditures	**328,006**	292,500
Canadian exploration expenditures	**4,253**	11,757
Undepreciated capital costs	**266,105**	184,586
Non-capital losses	**712,288**	775,727
Financing costs and other	**9,824**	10,334
Total Canadian tax pools	**$1,584,979**	$1,546,645
US Tax Pools		
Taxable depletion	**$ 92,871**	$ 125,628
Intangible drilling costs	**87,039**	35,000
Tangibles	**21,835**	3,634
Non-capital losses	**90,828**	66,530
Total US tax pools	**$ 292,573**	$ 230,792

Net Income

Net income for the year ended 2011 was $217.4 million, as compared to $231.6 million for the same period in 2010. This decrease in net income was primarily the result of higher deferred income tax expense, financial derivative losses and depletion and depreciation. This was partially offset by a decrease in share-based compensation and larger gains realized on sale of oil and gas properties compared to 2010.

Other Comprehensive Income

Revenues and expenses of foreign operations are translated to Canadian dollars using average foreign currency exchange rates for the period. Monetary assets and liabilities that form part of the net investment in the foreign operation are translated at the period-end foreign currency exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders'/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 $3.6 million balance of accumulated other comprehensive loss at December 31, 2011 is the sum of a $10.3 million foreign currency translation loss incurred in 2010 and a $6.8 million foreign currency translation gain for the year ended December 31, 2011 as USD/CAD foreign exchange rates strengthened at December 31, 2011.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS OR DISTRIBUTIONS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends/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):

	Years Ended	
($ thousands except for %)	**December 31, 2011**	December 31, 2010
Cash flow from operating activities	**$ 571,860**	$ 461,406
Change in non-cash working capital	**10,889**	11,704
Asset retirement expenditures	**10,588**	2,829
Financing costs	**(44,611)**	(34,570)
Accretion on asset retirement obligations	**6,185**	5,862
Accretion on debentures and long-term debt	**572**	426
Funds from operations	**$ 555,483**	$ 447,657
Cash dividends/distributions declared	**$ 281,047**	$ 243,382
Reinvested dividends/distributions	**75,087**	53,558
Cash dividends/distributions declared (net of DRIP)	**$ 205,960**	$ 189,824
Payout ratio	**51%**	54%
Payout ratio (net of DRIP)	**37%**	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 $206.0 million for the year ended December 31, 2011 were funded through funds from operations of $555.5 million.

The following table compares cash dividends or distributions declared (net of DRIP participation) to cash flow from operating activities and net income:

	Years Ended	
($ thousands)	December 31, 2011	December 31, 2010
Cash flow from operating activities	$ 571,860	$ 461,406
Cash dividends/distributions declared (net of DRIP)	205,960	189,824
Excess of cash flow from operating activities over cash dividends/distributions declared (net of DRIP)	$ 365,900	$ 271,582
Net income	$ 217,432	$ 231,615
Cash dividends/distributions declared (net of DRIP)	205,960	189,824
Excess (shortfall) of earnings over cash dividends/distributions declared (net of DRIP)	$ 11,472	$ 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.

For the year ended December 31, 2011, the Company's net income was in excess of cash dividends declared (net of DRIP participation) by $11.5 million, with net income reduced by $354.4 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)	December 31, 2011	December 31, 2010
Bank loan	$ 311,960	$ 303,773
Long-term debt[(1)]	302,550	150,000
Working capital deficiency	36,071	52,462
Total monetary debt	$ 650,581	$ 506,235

(1) Principal amount of instruments.

At December 31, 2011, total monetary debt was $650.6 million, as compared to $506.2 million at December 31, 2010. Bank borrowings at December 31, 2011 were $312.0 million, as compared to total credit facilities of $700.0 million.

Our wholly-owned subsidiary, Baytex Energy Ltd., has established credit facilities with a syndicate of chartered banks. On June 14, 2011, Baytex Energy reached agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the facilities to $700.0 million (from $650.0 million), (ii) extend the revolving period from 364 days (with a one-year term out following the revolving period) to three years, which is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time), and (iii) change the structure of the facilities from reserves-based to covenant-based (with standard commercial covenants for facilities of this nature). Baytex is in compliance with all financial covenants. The credit facilities do not require any mandatory principal payments during the three-year term. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or US funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain of our material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with covenants under the credit facilities, our ability to pay dividends to shareholders may be restricted. A copy of the amended and restated credit agreement which establishes the credit facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011).

Financing costs for the year ended December 31, 2011 include credit facility amendment fees of $2.3 million ($1.4 million for year ended December 31, 2010). The weighted average interest rate on the bank loan for year ended December 31, 2011 was 3.69% (3.94% for the year ended December 31, 2010).

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 Baytex Energy's credit facilities.

Baytex believes that funds from operations, together with the existing credit facilities, will be sufficient to finance current operations, dividends to the shareholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of dividend is also discretionary, and the Company has the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes.

Capital Expenditures

Capital expenditures are summarized as follows:

	Years Ended December 31	
($ thousands)	2011	2010
Land	$ 5,219	$ 12,774
Seismic	1,042	186
Drilling and completion	245,093	157,568
Equipment	116,513	61,211
Other	(19)	(120)
Total exploration and development	$ 367,848	$ 231,619
Acquisitions – Corporate	120,006	40,314
Acquisitions – Properties	76,164	22,412
Proceeds from divestitures	(47,396)	(19,033)
Total acquisitions and divestitures	148,774	43,693
Total oil and natural gas expenditures	516,622	275,312
Other plant and equipment, net	1,252	8,237
Total capital expenditures	$ 517,874	$ 283,549

For the year ended December 31, 2011, Baytex disposed of assets in Kaybob and Dodsland areas which consisted of $9.0 million of oil and gas properties and $2.1 million of exploration and evaluation assets for net cash proceeds of $47.4 million. Gains totaling $36.3 million were recognized in the statements of income and comprehensive income.

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 March 8, 2012, the Company had 118,755,036 common shares and no preferred shares issued and outstanding.

Off Balance Sheet Arrangements

Baytex is not party to any contractual arrangement under which a non-consolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to a non-consolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. Baytex has no obligation under financial instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company, or engages in leasing, hedging or research and development services with the Company.

Contractual Obligations

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations on an ongoing manner. A significant portion of these obligations will be funded with funds from operations. These obligations as of December 31, 2011, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 225,831**	$ 225,831	$ –	$ –	$ –
Dividends payable to shareholders	**25,936**	25,936	–	–	–
Bank loan(1)	**311,960**	–	311,960	–	–
Long-term debt(2)	**302,550**	–	–	150,000	152,550
Operating leases	**50,117**	5,753	11,884	12,228	20,252
Processing and transportation agreements	**5,198**	3,238	1,960	–	–
Total	**$ 921,592**	$ 260,758	$ 325,804	$162,228	$ 172,802

(1) The bank loan is a three-year covenant-based revolving loan that is extendible annually for a one, two or three year period (subject to a maximum three-year term at any time). Unless extended, the revolving period will end on June 14, 2014 with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex is exposed to a number of financial risks, including market risk, liquidity risk and credit risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is managed by Baytex through a series of derivative contracts intended to manage the volatility of its operating cash flow. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Baytex manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis.

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Company's control. Included in these risks are the uncertainty of finding new reserves, fluctuations in commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and Baytex competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing Baytex are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. Baytex's ability to increase its production, revenues and funds from operations depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future petroleum and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Company's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of members of the Board of Directors of Baytex (the "Board"), assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the impairment test are based on proved plus probable reserve estimates. Any future significant revisions could result in a write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that Baytex is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board. Derivative instruments are not used for speculative or trading purposes.

The Company's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, Baytex has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective of the risk management program is to decrease exposure to market volatility and ensure the Company's ability to finance its dividends and capital program.

Baytex's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar borrowings. The related foreign exchange gains and losses are included in net income.

Baytex is exposed to changes in interest rates as advances under Baytex Energy's credit facilities are based on the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates plus applicable margins.

A summary of the risk management contracts in place as at December 31, 2011 and the accounting treatment of the Company's financial instruments are disclosed in note 23 to the consolidated financial statements for the year ended December 31, 2011.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 2 and 3 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with GAAP requires management to make judgments and estimates that affect the financial results of the Company. The financial and operating results of Baytex incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion and depreciation that are based on estimates of petroleum and natural gas reserves that Baytex expects to recover in the future;
- estimated fair values of financial derivative contracts that are subject to fluctuation depending upon the underlying commodity prices, interest rates and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

Baytex has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Current Changes in Accounting Policies

Adoption of International Financial Reporting Standards

IFRS replaced previous GAAP in Canada for financial periods beginning on January 1, 2011. At the transition date, publicly accountable enterprises were 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.

Reconciliations to IFRS from the previously published consolidated financial statements, prepared in accordance with previous GAAP are shown in note 29 to the consolidated financial statements. The accounting policies described in note 3 to the consolidated financial statements set out those policies that have been applied retrospectively and consistently in preparing the consolidated financial statements, except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1 (as disclosed in note 29 to the consolidated financial statements).

The following table reconciles Baytex's 2010 previous GAAP results to IFRS for the year ended December 31, 2010:

($ thousands)	
Net income – Previous GAAP	$177,631
Exploration and evaluation	(24,502)
Depletion and depreciation	63,731
Gain on oil and gas properties	16,227
Accretion on asset retirement obligation	(1,348)
Unit-based compensation	(85,855)
Conversion feature of convertible debentures	(5,118)
Deferred income tax	92,180
Other	(1,331)
Net income – IFRS	$231,615

($ thousands)	
Funds from operations – Previous GAAP	$454,183
Exploration and evaluation	(5,610)
Other	(916)
Funds from operations – IFRS	$447,657

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.

For the year ended December 31, 2010, Baytex had exploration and evaluation capital expenditures of $37.4 million, corporate acquisitions of $2.5 million, divestitures of $0.1 million, transfers to oil and gas properties of $29.1 million, transfers to expense related to lease expiries of $18.9 million and a decrease due to foreign currency translation of $3.3 million. For the year ended December 31, 2010, Baytex expensed $18.9 million of exploration and evaluation assets related to lease expiries and $5.6 million in direct exploration costs.

Depletion

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

There was no impact to depletion on transition to IFRS at January 1, 2010. Upon adoption of IFRS, for the year ended December 31, 2010, the change in accounting policy resulted in a decrease in depletion expense of $67.4 million with a corresponding increase in oil and natural gas properties.

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 transition 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 natural gas properties. Under previous GAAP, the Company used a credit-adjusted risk free 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 current discount rates at each remeasurement date with the corresponding adjustment to the cost of the related oil and natural gas properties. Existing liabilities under previous GAAP are not re-measured 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.

For the year ended December 31, 2010, $4.5 million was reclassified to finance costs and an additional accretion expense of $1.4 million on asset retirement has been recognized in net income under IFRS.

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 resulted in a corresponding $71.2 million charge to deficit.

Under IFRS, in addition to the January 1, 2010 adjustments discussed above, at December 31, 2010 (immediately prior to the conversion to a corporation) the remeasurement of the liability at reporting date and at settlement date resulted in the recognition of additional unit-based compensation expense of $85.9 million, 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.

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.

In May 2010, 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, deferred income tax recovery of $109.8 million was recorded in net income for amounts previously recognized as a deferred credit.

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.

Future Changes in Accounting Policies

Financial Instruments

The International Accounting Standards Board (the "IASB") published IFRS 9, "Financial Instruments" which replaces IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: at amortized cost or fair value.

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.

Consolidation, Joint Ventures and Disclosures

In May 2011, the IASB issued new standards, IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements" and IFRS 12, "Disclosure of Interests in Other Entities". IAS 27, "Separate Financial Statements" and IAS 28, "Investments in Associates and Joint Ventures" were amended based on the issuance of IFRS 10, IFRS 11 and IFRS 12. Each of the new and revised standards is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The adoption of these standards may have an impact on the consolidated financial statements of the Company.

Consolidated Financial Statements

IFRS 10, "Consolidated Financial Statements" replaces the consolidation guidance in IAS 27, "Consolidated and Separate Financial Statements" by introducing a single consolidation model for all entities based on control, irrespective of the nature of the investee. Under IFRS 10, control is based on whether an investor has: (1) power over the investee; (2) exposure, or rights, to variable returns from its involvement with the investee; and (3) the ability to use its power over the investee to affect the amount of the returns.

Joint Arrangements

IFRS 11, "Joint Arrangements" replaces IAS 31, "Interest in Joint Ventures". The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted.

Disclosure of Interests in Other Entities

IFRS 12, "Disclosure of Interests in Other Entities", requires enhanced disclosures about both consolidated entities and unconsolidated entities in which an entity has involvement. The objective of IFRS 12 is to require information so that financial statement users may evaluate the basis of control, any restrictions on consolidated assets and liabilities, risk exposures arising from involvements with unconsolidated structured entities and non-controlling interest holders' involvement in the activities of consolidated entities.

Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "Fair Value Measurement" which replaces the guidance on fair value measurement in existing IFRS accounting literature with a single standard. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 with early application permitted. The adoption of this standard may have an impact on the consolidated financial statements of the Company.

Presentation of Financial Statements

In June 2011, the IASB amended IAS 1, "Presentation of Financial Statements" to require companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income that may be reclassified to the net income section of the income statement. The amendments also reaffirm existing requirements that items in other comprehensive income and profit or loss should be presented as either a single statement or two consecutive statements. The amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the consolidated financial statements of the Company.

SELECTED ANNUAL INFORMATION

($ thousands, except per common share or trust unit amounts)	2011	2010
Petroleum and natural gas sales	$ 1,305,814	$ 1,003,295
Net income[1]	$ 217,432	$ 231,615
Per common share or trust unit – basic[1]	$ 1.88	$ 2.08
Per common share or trust unit – diluted[1]	$ 1.83	$ 2.01
Total assets	$ 2,461,810	$ 1,981,023
Total other long-term financial liabilities	$ 609,691	$ 450,666
Cash dividends or distributions declared per common share or trust unit	$ 2.42	$ 2.18
Average wellhead prices, net of blending costs	$ 61.26	$ 53.39
Total production (boe/d)	50,132	44,341

(1) Net income and net income per common share or trust unit is after non-controlling interest related to exchangeable shares.

FOURTH QUARTER OF 2011

For a discussion and analysis of our operating and financial results for the three months ended December 31, 2011, please see our Management's Discussion and Analysis for the three months and year ended December 31, 2011 dated March 13, 2012, which is incorporated by reference into this MD&A and is accessible on SEDAR at www.sedar.com.

2012 GUIDANCE

We have set a 2012 exploration and development capital budget of $400 million, which is designed to generate production levels at an average annual rate of 54,000 to 55,000 boe/d.

We view 2011 as the year in which we completed our shift from a predominantly income-focused model as a trust to a growth-and-income model in our new corporate era. Our 2012 capital program reflects the continuation and advancement of the growth-and-income model. Based on the mid-point of the production guidance ranges for 2011 and 2012, our 2012 plan reflects an organic production growth rate of 8% based on oil-equivalent production, and 11% for oil production. Our 2012 production mix is forecast to be approximately 69% heavy oil, 16% light oil and natural gas liquids and 15% natural gas, based on a 6:1 natural gas-to-oil equivalency.

Approximately 60% of our 2012 capital budget will be invested in our heavy oil operations, with the majority being directed to cold primary horizontal well development at Seal in the Peace River Oil Sands. This budget also includes funding to begin drilling and facility construction on a second module of commercial thermal development at Seal. The second thermal module is planned as a 15-well cyclic steam stimulation (CSS) project. Subject to receipt of regulatory approvals, we expect to commence development of this project in the fourth quarter of 2012 and be completed in the first quarter of 2013. Our capital budget for the Lloydminster area is directed primarily at cold drilling, with horizontal wells comprising the majority of drilling capital. The balance of our capital program will be directed primarily towards light oil development, with the two largest projects being the Bakken/Three Forks in North Dakota and the Viking in southeast Alberta.

ENVIRONMENTAL REGULATION AND RISK

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities.

Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs.

Climate Change Regulation

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Kyoto Protocol"), which requires a reduction in greenhouse gas ("GHG") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005, although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol. In December 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both GHG emissions and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "Updated Action Plan"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In January 2012, representatives from the Government of Canada indicated that flexibility may be introduced into the proposed regulations which would allow for Provinces to set their own emissions targets, as long as they have rules in place that would achieve equivalent reductions. As a result of ensuring consistency with the United States and the possibility that emissions targets will be Province specific, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

In addition to federal commitments and legislation, Province specific legislation also imposes GHG emission standards and regulations which may impact Baytex and its operations and financial condition. The implementation of strategies for reducing GHG, whether to meet the goals of the Copenhagen Accord, the Cancun Agreements, federal or provincial regulations, or otherwise, could have a material impact on the nature of oil and natural gas operations, including those of Baytex. Given the evolving nature of the debate related to climate changes and the regulation of GHG, it is not possible to predict the impact of those requirements, or future requirements, on Baytex and its operations and financial condition.

Further information regarding environmental and climate change regulation is contained in our Annual Information Form for the year ended December 31, 2011 under the "Industry Conditions – Climate Change Regulation" section.

DISCLOSURE CONTROL AND PROCEDURES

As of December 31, 2011, an evaluation was conducted of the effectiveness of the Baytex's "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in

Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the Baytex's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Baytex files or submits under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Baytex's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Baytex. "Internal control over financial reporting" (as defined in the United States by Rules 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Baytex's financial statements for external reporting purposes in accordance with Canadian GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Additionally, projections of any evaluations of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with Baytex's policies and procedures. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011 based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2011. The effectiveness of the Baytex's internal control over financial reporting as of December 31, 2011 has been audited by Deloitte & Touche LLP, as reflected in their report for 2011.

No changes were made to our internal control over financial reporting during the year ended December 31, 2011.

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 timing of payment of Canadian income taxes; 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; our exploration and development capital expenditures for 2012; our average production rate for 2012; our production growth rates for 2012; our production mix for 2012; the allocation of our exploration and development capital expenditures for 2012; our heavy oil resource play at Seal, including the timing of completing a 15-well cyclic steam stimulation project; and the impact of new environmental and climate change regulations on 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. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.*

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

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and natural gas operations; changes in royalty rates and incentive programs relating to the oil and natural gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; the failure to obtain the necessary regulatory and other approvals on planned timelines; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2011, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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