MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Trust ("Baytex" or the "Trust") for the year ended December 31, 2009. This information is provided as of March 15, 2010. In this MD&A, references to "Baytex", the "Trust", "we", "us" and "our" and similar terms refer to Baytex Energy Trust and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Trust's audited consolidated comparative financial statements for the years ended December 31, 2009 and 2008, together with accompanying notes, and the Annual Information Form ("AIF") for the year ended December 31, 2009. The Trust's audited consolidated comparative financial statements, MD&A and AIF for the year ended December 31, 2009 will be filed in late March 2010. These documents and additional information about the Trust will be available on SEDAR at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentage and per 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.

Non-GAAP Financial Measures

The Trust evaluates performance based on net income and funds from operations. Funds from operations is not a measurement based on Generally Accepted Accounting Principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers funds from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders 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 Distributions".

Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial instrument gains or losses)), the principal amount of long-term debt and the balance sheet amount of the convertible debentures.

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

OUTLOOK – ECONOMIC ENVIRONMENT

The current economic environment continues to show signs of recovery from the recent financial crisis. This improving economic backdrop has contributed to the recent relative strength in oil prices. Sustaining this recent improvement in oil prices will depend on a combination of demand stabilization through economic recovery and natural production declines around the world due to reduced capital investment. In this economic environment Baytex is focused on the following objectives: preserving balance sheet strength and liquidity, maintaining and where possible, profitably expanding its productive capacity and delivering a sustainable distribution to its unitholders.

2009 OVERVIEW

Baytex Energy Trust is an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to a trust indenture. Baytex was established on September 2, 2003 in connection with a Plan of Arrangement of our subsidiary, Baytex Energy Ltd. (the "Company"). Through our subsidiaries, we are actively engaged in the exploration, development and production of oil, natural gas and natural gas liquids in Canada in the provinces of British Columbia, Alberta and Saskatchewan and in the United States in the states of North Dakota and Wyoming.

Our business objective has been to maintain production levels through investing approximately half of our internally generated cash flow into exploration and development ("E&D") activities while distributing most of the balance of our cash flow to holders of our trust units. Over our life, we have grown our reserve base and added to production levels through E&D activities complimented by strategic acquisitions.

During 2009, the Trust executed a successful capital program, resulting in the replacement of 113% of production (on a proved plus probable basis) by reinvesting 47% of our internally generated funds from operations into E&D activities. When acquisitions are included, the Trust replaced 165% of production.

As at December 31, 2009, we had a reserve base of 197 million (gross) boe on a proved plus probable basis. During the year ended December 31, 2009, our production averaged 41,382 boe/d, primarily from Canada.

On April 14, 2009, we completed a bought deal equity financing, issuing 7.9 million trust units for net proceeds of $109.0 million. Proceeds of this offering were used to repay bank debt.

On July 30, 2009, we closed the acquisition of certain oil and natural gas properties located primarily in the Kerrobert and Coleville areas of Saskatchewan. These assets were producing approximately 3,000 boe/d at the time of the acquisition, and the net purchase price was approximately $86.5 million. This acquisition was funded with a draw on our credit facilities.

On August 26, 2009, we closed the issuance of $150 million of senior unsecured debentures, and used the proceeds to partially fund the redemption of US$180 million of senior subordinated notes. The balance of redemption proceeds were funded with a draw on our credit facilities.

In December 2009, we prepaid the balance of our outstanding deferred land acquisition payments with respect to the North Dakota lands we obtained in 2008. This payment of US$33.2 million, which would otherwise have totaled US$36 million over approximately the next five to six quarters, provided greater and accelerated operating control over our interests in our North Dakota lands.

RESULTS OF OPERATIONS

Production

	Years Ended December 31		
	2009	2008	Change
Daily Production			
Light oil and NGL (bbl/d)	**6,937**	7,575	(8%)
Heavy oil (bbl/d)[(1)]	**24,678**	23,530	5%
Natural gas (mmcf/d)	**58.6**	54.8	7%
Total production (boe/d)	**41,382**	40,239	3%
Production Mix			
Light oil and NGL	**17%**	19%	(11%)
Heavy oil	**60%**	58%	3%
Natural gas	**23%**	23%	0%

(1) Heavy oil sales may differ from reported production volumes due to adjustments to Baytex's heavy oil inventory. In the year ended December 31, 2009 heavy oil sales were 91 bbl/d lower than production volume (December 31, 2008 – increase of 300 bbl/d).

Total production for the year ended December 31, 2009 was 41,382 boe/d, a 3% increase from the year ended December 31, 2008 of 40,239 boe/d. For the year ended December 31, 2009, light oil and NGL production decreased by 8% to 6,937 bbl/d from 7,575 bbl/d last year due to production declines on conventional fields in Alberta and British Columbia. Heavy oil production for the year ended December 31, 2009 increased by 5% to 24,678 bbl/d compared to 23,530 bbl/d for 2008. Natural gas production increased by 7% to 58.6 mmcf/d for 2009 compared to 54.8 mmcf/d for 2008. The increase in production of both heavy oil and natural gas during 2009 was due primarily to the acquisition of producing assets in southwest Saskatchewan on July 30, 2009.

MARKETING

Crude Oil

In January 2009, as the global financial crisis deepened and most of the world's economies contracted, the price of oil (West Texas Intermediate, or "WTI") hit a low of US$32.70/bbl. However, as it became clear that the Organization of the Petroleum Exporting Countries ("OPEC") was largely adhering to its December 2008 pledge to curtail production by 4.2 million barrels per day, oil prices began an erratic but sustained increase that continued for the balance of 2009. Although global oil demand remained substantially below 2008 levels and global petroleum inventories remained high, particularly in the Organization for Economic Co-operation and Development ("OECD") countries, oil demand growth from non-OECD countries helped support oil prices as 2009 progressed. WTI reached a high of US$82.00/bbl in October 2009, capping a near US$50/bbl oil price increase from the low in January. As shown in the table below, the average price of WTI for the year ended December 31, 2009 was US$61.80/bbl, 38% lower than the average for 2008.

Compared to the volatility of WTI prices in 2009, the relative value of the Western Canadian Select ("WCS") heavy crude oil blend was less volatile than in 2008. As shown in the table below, the WCS differential averaged 16% for the year ended December 31, 2009, a significant improvement versus the respective 2008 discount of 22%. This improvement in heavy oil differentials resulted from a number of North American and global supply and demand factors, including increased demand from North American and Asian refineries that have been reconfigured to run more heavy oil, reduced output of heavy oil by traditional suppliers such as Mexico, and sufficient pipeline capacity from Canada to the U.S. to ensure access to a growing number of refineries.

Natural Gas

In contrast to oil's upward price trend in 2009, natural gas prices declined for much of the year as reflected in the table below. The average AECO price during 2009 was $4.14/mcf versus $8.13/mcf in 2008. The main drivers of the decline in natural gas prices in 2009 were two-fold: reduced demand by U.S. commercial and industrial consumers due to the economic downturn and sustained production from shale gas drilling. Although natural gas directed drilling activity declined significantly with the U.S. financial crisis, increased well productivity from horizontal drilling and multi-stage fracturing largely mitigated the reduced level of drilling activity. As a result, North American natural gas storage entered the winter of 2009/2010 at record levels, which depressed prices. Natural gas prices did rally in late 2009, due to the effects of sustained cold weather across much of the U.S. and Canada.

	Years Ended December 31		
	2009	2008	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	$ 61.80	$ 99.59	(38%)
WCS heavy (US$/bbl)[2]	$ 52.14	$ 79.59	(34%)
Heavy oil differential[3]	(16%)	(22%)	(27%)
USD/CAD exchange rate	0.8760	0.9371	(7%)
Edmonton par oil ($/bbl)	$ 66.20	$ 102.86	(36%)
AECO natural gas price ($/mcf)[4]	$ 4.14	$ 8.13	(49%)
Baytex Average Sales Prices			
Light oil and NGL ($/bbl)	$ 54.25	$ 88.92	(39%)
Heavy oil ($/bbl)[5][6]	$ 55.01	$ 72.84	(24%)
Physical forward sales contracts (loss) ($/bbl)	(5.13)	(7.62)	(33%)
Heavy oil, net ($/bbl)	$ 49.88	$ 65.22	(24%)
Total oil and NGL, net ($/bbl)	$ 50.85	$ 70.94	(28%)
Natural gas ($/mcf)[6]	$ 4.09	$ 8.11	(50%)
Physical forward sales contracts gain (loss) ($/mcf)	0.26	(0.19)	(237%)
Natural gas, net ($/mcf)	$ 4.35	$ 7.92	(45%)
Summary			
Weighted average ($/boe)[6]	$ 48.23	$ 71.49	(33%)
Physical forward sales contracts gain (loss) ($/boe)	(3.23)	(5.83)	(45%)
Weighted average, net ($/boe)	$ 45.00	$ 65.66	(31%)

(1) *WTI refers to the calendar monthly average based on Nymex prompt month WTI.*
(2) *WCS refers to the posting price of the benchmark heavy oil price.*
(3) *Heavy oil differential refers to the WCS discount to WTI.*
(4) *AECO refers to the AECO monthly published Canadian Gas Price Reporter posting.*
(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 heavy oil). The above table excludes impact of financial instruments.*

For the full year 2009, Baytex's average sales price for light oil and NGL was $54.25/bbl, down 39% from $88.92/bbl in 2008. Baytex's realized heavy oil price in 2009, prior to physical forward sales contracts was $55.01/bbl, or 92% of the benchmark WCS price. 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 in 2009 was $49.88/bbl, down 24% from $65.22/bbl in 2008. Baytex's realized natural gas price in 2009 was $4.09/mcf, prior to physical forward sales contracts, and $4.35/mcf inclusive of physical forward sales contracts.

Revenue

($ thousands except for %)	Years Ended December 31 2009	2008	Change
Oil revenue			
Light oil and NGL	$ 137,379	$ 246,516	(44%)
Heavy oil	447,674	568,841	(21%)
Total oil revenue	585,053	815,357	(28%)
Natural gas revenue	93,132	158,845	(41%)
Total oil and natural gas revenue	678,185	974,202	(30%)
Sulphur revenue	786	6,820	(88%)
Other income	77	2,000	(96%)
Sales of heavy oil blending diluent	110,772	176,696	(37%)
Total petroleum and natural gas sales	$ 789,820	$ 1,159,718	(32%)

For the year ended December 31, 2009, light oil and NGL revenue decreased 44% from the same period last year due to a 39% decrease in wellhead prices and an 8% decrease in sales volume. Revenue from heavy oil decreased 21% percent due to a 24% decrease in wellhead prices, offset by a 5% increase in volumes. Revenue from natural gas decreased 41% compared to 2008 primarily due to a 45% decrease in realized commodity price offset by a 7% increase in production.

For the year ended December 31, 2009, sulphur production averaged 45.9 tonnes per day with an average price of $47 per tonne, as compared to 48.9 tonnes per day with an average price of $381 per tonne in 2008.

Royalties

($ thousands except for % and per boe)	Years Ended December 31 2009	2008	Change
Royalties	$ 130,715	$ 207,522	(37%)
Average royalty rate(1)	19.3%	21.2%	(9%)
Royalty expenses per boe	$ 8.67	$ 13.99	(38%)

(1) Royalty rate excludes sales of heavy oil blending diluents and the effects of financial instruments.

For the year ended December 31, 2009, royalties decreased to $130.7 million from $207.5 million for 2008. Total royalties for 2009 were 19.3% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent and other), as compared to 21.2% for 2008. For 2009, royalties were 20.5% of revenue for light oil, NGL and natural gas (2008 – 23.0%) and 18.7% for heavy oil (excluding sales of heavy oil blending diluent and other), (2008 – 19.8%). The decrease of 9% in the overall royalty rate is primarily due to lower commodity prices and new Alberta royalty incentive programs. 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 in royalties.

Financial Instruments

($ thousands)	Years Ended December 31 2009	2008	Change
Realized gain (loss) on financial instruments[1]			
Crude oil	$ 62,076	$ (51,367)	$ 113,433
Natural gas	3,565	–	3,565
Foreign currency	15,177	(8,734)	23,911
Total	$ 80,818	$ (60,101)	$ 140,919
Unrealized gain (loss) on financial instruments[2]			
Crude oil	$ (77,093)	$ 115,910	$ (193,003)
Natural gas	(1,142)	–	(1,142)
Foreign currency	23,804	4,007	19,797
Interest swaps	(379)	–	(379)
Total	$ (54,810)	$ 119,917	$ (174,727)
Total gain (loss) on financial instruments			
Crude oil	$ (15,017)	$ 64,543	$ (79,560)
Natural gas	2,423	–	2,423
Foreign currency	38,981	(4,727)	43,708
Interest swaps	(379)	–	(379)
Total	$ 26,008	$ 59,816	$ (33,808)

(1) Realized gain (loss) on financial instruments represents actual cash settlement or receipts under the respective financial instruments.

(2) Unrealized gain (loss) on financial instruments represents the change in fair value of the financial instruments during the year.

The gain on financial instruments for the year ended December 31, 2009 was $26.0 million compared to a gain of $59.8 million in 2008. The realized gain of $80.8 million in 2009 is mostly attributable to crude oil and foreign currency contracts. The 2009 realized gain is offset by unrealized mark-to-market losses of $54.8 million compared to $60.1 million in realized losses and $119.9 million in unrealized gains in the year ended 2008. The significant unrealized mark-to-market gain in the year ended December 31, 2008 was due to the significant decline in the crude oil price at the end of 2008 compared to the end of 2007. The unrealized mark-to-market loss on the crude oil contracts results from the change in fair value of the contracts during the period.

Details of the risk management contracts in place as at December 31, 2009, and the accounting for the Trust's financial instruments are disclosed in note 18 to the consolidated financial statements.

Operating Expenses

($ thousands except for % and per boe)	Years Ended December 31 2009	2008	Change
Operating expenses	$ 163,250	$ 172,471	(5%)
Operating expenses per boe	$ 10.83	$ 11.62	(7%)

Operating expenses for the year ended December 31, 2009 decreased to $163.3 million from $172.5 million in 2008. Operating expenses were $10.83 per boe for 2009 compared to $11.62 per boe for the prior year. In 2009, operating expenses were $11.70 per boe of light oil, NGL and natural gas and $10.24 per barrel of heavy oil, as compared to $11.73 and $11.55, respectively, in 2008. In the case of heavy oil, the reduction in per barrel operating expense is a result of reductions in the cost of energy and services inputs as well as higher production levels.

Transportation and Blending Expenses

Transportation and blending expenses for the year ended December 31, 2009 were $159.4 million compared to $218.7 million for 2008.

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. The cost of diluent is effectively recovered in the sale price of a blended product. For the year ended December 31, 2009, the blending cost was $110.8 million for the purchase of 4,240 bbl/d of condensate at $71.58 per barrel, as compared to $176.7 million for the purchase of 4,377 bbl/d at $110.30 per barrel in 2008.

	Years Ended December 31		
($ thousands except for % and per boe)	2009	2008	Change
Transportation expenses[1]	$ 48,582	$ 42,010	16%
Transportation expense per boe[1]	$ 3.22	$ 2.83	14%

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

Transportation expenses for 2009 include $1.0 million related to the transportation of sulphur compared to $1.3 million in the year ended in 2008. Transportation expenses before blending costs were $3.22 per boe for 2009 compared to $2.83 per boe in 2008. Transportation expenses were $0.79 per boe of light oil, NGL and natural gas and $4.88 per barrel of heavy oil in 2009, compared to $0.86 and $4.22, respectively, in 2008.

Operating Netback

	Years Ended December 31		
($ per boe except for % and volume)	2009	2008	Change
Sales volume (boe/d)	41,291	40,539	2%
Operating netback ($/boe)[1]:			
Sales price[2]	$ 45.00	$ 65.66	(32%)
Less:			
Royalties	8.67	13.99	(38%)
Operating expenses	10.83	11.62	(7%)
Transportation expenses	3.22	2.83	14%
Operating netback before hedging	$ 22.28	$ 37.22	(40%)
Financial instruments gain (loss)[3]	5.36	(4.05)	232%
Operating netback after hedging	$ 27.64	$ 33.17	(17%)

(1) Netback table includes revenues and costs associated with sulphur production.
(2) Sales prices are shown net of blending costs and gains (losses) on physical delivery contracts.
(3) Financial instruments reflect realized derivative gains (losses) only.

General and Administrative Expenses

	Years Ended December 31		
($ thousands except for % and per boe)	2009	2008	Change
General and administrative	$ 35,006	$ 29,603	18%
General and administrative per boe	$ 2.32	$ 2.00	16%

General and administrative expenses for the year ended December 31, 2009 were $35.0 million, compared to $29.6 million for the prior year. The increase is primarily attributable to a $3.4 million non-recurring tax indemnification payment made on behalf of certain employees who experienced unintended adverse U.S. income tax consequences related to participation in our trust unit rights incentive plan. Excluding this one-time item, G&A

per boe would have been $2.10 per boe for 2009 compared to $2.00 per boe in 2008. Including this one time item, on a per sales unit basis, G&A expenses were $2.32 per boe in 2009. During 2009, higher consulting and office costs were incurred in Canada and the U.S. due to a full year of expenses associated with the expansion of the Denver office to manage our U.S. operations. This increase was partially offset by higher operating overhead recoveries compared to the prior year.

Unit-based Compensation Expense

For the year ended December 31, 2009, compensation expense was $6.4 million, a decrease of 18% compared to $7.8 million for the same period in 2008. Compensation expense associated with our trust unit rights incentive plan is recognized in income over the vesting period of the rights with a corresponding increase in contributed surplus. The exercise of rights is recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Interest Expense

Interest expense for the year ended December 31, 2009 was $32.7 million compared to $32.5 million in 2008. Interest on the bank loan decreased by $1.9 million compared to the year ended December 31, 2008. This is offset by the recognition of the remaining $1.6 million of accretion expense on the discounted fair value hedge upon retirement of the senior subordinated notes at September 25, 2009.

Financing Charges

Financing charges for the year ended December 31, 2009 increased to $5.5 million compared to $0.5 million in 2008. The majority of the increase consists of transaction costs of $3.6 million for the issuance of $150 million of senior unsecured debentures on August 26, 2009 as well as a commitment fee of $1.8 million to amend and extend the credit facility.

Foreign Exchange

Foreign exchange gain for the year ended December 31, 2009 was $22.8 million compared to a loss of $37.7 million in the prior year. The major component of the realized gain for 2009 is the gain of $23.7 million realized on the retirement of the US$ senior subordinated notes ($nil for 2008) on September 25, 2009. The loss for the year ended December 31, 2008 is based on the translation of the US$ senior subordinated notes at 1.2246 USD/CAD compared to 0.9881 USD/CAD at December 31, 2007.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $237.2 million for the year ended December 31, 2009 compared to $223.9 million in 2008. On a sales-unit basis, the provision for the current year was $15.74 per boe compared to $15.09 per boe in 2008. The increase is attributable to a higher capital base due to the acquisition of the assets in southwest Saskatchewan on July 30, 2009.

Taxes

Current tax expense of $11.4 million for the year ended December 31, 2009 is $1.2 million higher than the $10.2 million recorded in 2008.

As at December 31, 2009, total future tax liability of $186.6 million (December 31, 2008 – $217.8 million) consisted of a $1.4 million current future tax asset (December 31, 2008 – $nil), $0.4 million long-term future tax asset (December 31, 2008 – $nil), $8.7 million current future tax liability (December 31, 2008 – $25.4 million) and a $179.7 million long-term future tax liability (December 31, 2008 – $192.4 million). The decrease from the prior year is due to lower funds from operations and recognition of non-capital losses previously included in the valuation allowance.

Tax Pools

($ thousands)	December 31, 2009	December 31, 2008
Cumulative Canadian oil and gas property expense	$ 299,220	$ 217,260
Cumulative Canadian development expense	189,791	193,319
Cumulative Canadian exploration expense	–	53,047
Undepreciated capital cost	241,071	249,306
Other	19,639	27,741
Total Canadian tax pools	$ 749,721	$ 740,673
Taxable depletion	$ 148,031	$ 113,520
Tangibles	3,686	2,133
Intangible drilling costs	9,182	1,132
Other	4,178	–
Total U.S. tax pools	$ 165,077	$ 116,785

Net Income

Net income for the year ended December 31, 2009 was $87.6 million compared to $259.9 million for the same period in 2008. Revenues, net of royalties, decreased $293.1 million or 31% for the year ended December 31, 2009 compared to the same period in 2008. This decrease is attributable to lower commodity prices for the full year 2009, partially offset by a decrease of $9.2 million in operating expenses for the year ended December 31, 2009 compared to the same period in 2008. Other factors that offset the decrease in revenues, net of royalties, included a $59.3 million decrease in transportation and blending expenses, a $60.6 million increase in foreign exchange gain and a $45.8 million increase in the future tax recovery.

Other Comprehensive Loss

The Trust's foreign operations are considered to be "self-sustaining operations", financially and operationally independent, as of January 1, 2009. As a result, the accounts of the self-sustaining foreign operations are translated using the current rate method whereby assets and liabilities are translated using the exchange rate in effect at the balance sheet date (0.9555 USD/CAD), while revenues and expenses are translated using the average exchange rate for the year ended December 31, 2009 (0.9467 USD/CAD). Translation gains and losses are deferred and included in other comprehensive income in unitholders' capital and are recognized in net income when there has been a reduction in the net investment.

Previously, foreign operations were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate while other assets and liabilities were translated at the historical rate. Revenues and expenses were translated at the average monthly rate except for depletion, depreciation and accretion, which were translated on the same basis as the assets to which they relate. Translation gains and losses were included in the determination of net income for the period.

This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties. An addition of $3.4 million, a reduction of $9.8 million, a reduction of $9.7 and a reduction of $3.2 million were recognized in the first, second, third and fourth quarters of 2009, respectively, resulting in a balance of $3.9 million in accumulated other comprehensive loss at December 31, 2009.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DISTRIBUTIONS

Funds from operations and payout ratio are non-GAAP terms. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's payout ratio is calculated as cash distributions (net of participation in the Distribution Reinvestment Plan ("DRIP")) divided by funds from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund distributions 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 December 31	
($ thousands except for %)	2009	2008
Cash flow from operating activities	$ 303,162	$ 471,237
Change in non-cash working capital	27,878	(38,857)
Asset retirement expenditures	1,146	1,443
Funds from operations	$ 332,186	$ 433,823
Cash distributions declared(1)	$ 137,601	$ 197,026
Payout ratio	41%	45%

(1) Cash distributions declared are net of DRIP participation.

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and 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 oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions declared, net of DRIP participation, of $137.6 million for the year ended December 31, 2009 were funded through funds from operations of $332.2 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	Years Ended December 31	
($ thousands except for %)	2009	2008
Cash flow from operating activities	$ 303,162	$ 471,237
Cash distributions declared	137,601	197,026
Excess of cash flow from operating activities over cash distributions declared	$ 165,561	$ 274,211
Net income	$ 87,574	$ 259,894
Cash distributions declared	137,601	197,026
Excess (shortfall) of net income over cash distributions declared	$ (50,027)	$ 62,868

It is Baytex's long-term operating objective to substantially fund cash distributions 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 distributions. 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 distributions and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing.

As at December 31, 2009, Baytex had approximately $198 million in available undrawn credit facilities to fund any such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital. For the year ended December 31, 2009, the Trust's cash distributions declared exceeded net income by $50.0 million, with net income reduced by $215.6 million for non-cash items. Non-cash items such as depletion, depreciation and accretion 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

As a result of the recent economic crisis, there have been periodic disruptions in the availability of credit. In light of this situation, we have undertaken a thorough review of 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 and, where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At December 31, 2009, total net monetary debt was $474.3 million compared to $533.0 million at the end of 2008. Bank borrowings and working capital deficiency at the end of 2009 were $316.5 million compared to total credit facilities of $515.0 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. 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 were increased from $485.0 million to $515.0 million in June 2009. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of our assets.

The credit facilities were arranged pursuant to an agreement with a syndicate of financial institutions. A copy our 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 and October 5, 2009).

In August 2009, Baytex closed its offering of $150 million principal amount of 9.15% Series A senior unsecured debentures due August 26, 2016. Baytex used the net proceeds from the offering of the debentures of $147 million (after agents' fees but before deduction of other offering expenses), along with funds drawn on its credit facilities, to fund the redemption price for the following senior subordinated notes of its subsidiary, Baytex Energy Ltd.: 9.625% notes due July 15, 2010 (principal amount US$179.7 million) and 10.5% notes due February 15, 2011 (principal amount US$0.2 million).

Pursuant to various agreements with our lenders, we are restricted from making distributions to unitholders where the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities upon a material borrowing base shortfall or default.

The Trust believes that cash flow generated from operations, together with the existing credit facilities, will be sufficient to finance current operations, distributions to the unitholders 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 distribution is also discretionary, and the Trust has the ability to modify distribution levels should funds from operations be negatively impacted by factors such as reduction in commodity prices.

Capital Expenditures

Capital expenditures are summarized as follows:

	Years Ended December 31	
($ thousands)	2009	2008
Land	$ 13,514	$ 9,534
Seismic	2,222	4,947
Drilling and completion	113,959	132,296
Equipment	26,164	34,720
Other	1,185	3,181
Total exploration and development	$ 157,044	$ 184,678
Corporate acquisition	$ –	$ 180,467
Property acquisitions	133,155	84,826
Property dispositions	(78)	(194)
Total oil and natural gas expenditures	$ 290,121	$ 449,777
Corporate assets	7,050	405
Total capital expenditures	$ 297,171	$ 450,182

Unitholders' Equity

The Trust is authorized to issue an unlimited number of trust units. As at March 5, 2010, the Trust had 110,347,769 trust units issued and outstanding.

At March 5, 2010, the Trust had a principal amount of $7.2 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit. The convertible debentures mature on December 31, 2010, at which time they are due and payable.

Non-controlling Interest

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this retirement, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008 of 1.79560. As at December 31, 2008, there were no exchangeable shares 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 Trust, or engages in leasing, hedging or research and development services with the Trust.

Contractual Obligations

The Trust has a number of financial obligations in the ordinary course of business. These obligations are of a recurring nature and impact the Trust's funds from operations in an on-going manner. A significant portion of these obligations will be funded through funds from operations. These obligations as of December 31, 2009, 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
Accounts payable and accrued liabilities	$ 180,493	$ 180,493	$ –	$ –	$ –
Distributions payable to unitholders	19,674	19,674	–	–	–
Bank loan[1]	265,088	265,088	–	–	–
Long-term debt[2]	150,000	–	–	–	150,000
Convertible debentures[2]	7,815	7,815	–	–	–
Operating leases	40,014	3,408	7,659	7,499	21,448
Processing and transportation agreements	7,708	4,328	3,251	129	–
Total	$ 670,792	$ 480,806	$ 10,910	$ 7,628	$ 171,448

(1) The bank loan is a 364-day revolving loan with the ability to extend the term. Unless extended, the bank loan will mature on June 30, 2010.

(2) Principal amount of instruments.

The Trust also has on-going 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.

RISK MANAGEMENT

Financial Instruments and Risk Management

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 Trust'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 the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust 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. The Trust's ability to increase its production, revenues and cash flow 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 Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of members of the Board of Directors of the Company (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 ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust 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 Trust'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, the Trust 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 Trust's ability to finance its distributions and capital program.

The Trust'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.

The Trust is exposed to changes in interest rates as the Company's credit facilities are based on the lenders' prime lending rate, LIBOR, and short-term bankers' acceptance rates.

Details of the risk management contracts in place as at December 31, 2009, and the accounting for the Trust's financial instruments are disclosed in note 18 to the consolidated financial statements. A summary of certain risk factors relating to our business is included in our Annual Information Form for the year ended December 31, 2009 under the Risk Factors section.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 1 and 2 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. The financial and operating results of the Trust 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, depreciation and accretion that are based on estimates of oil and natural gas reserves that the Trust expects to recover in the future;
- estimated fair values of 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.

The Trust 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

Recent Accounting Changes

Effective January 1, 2009, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") accounting standards Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The adoption of this new standard did not have a material impact on the consolidated financial statements of the Trust.

Effective January 1, 2009, the Trust adopted the CICA issued EIC-173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". EIC-173 provides guidance on how to take into account the credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of EIC-173 did not have a material impact on the consolidated financial statements of the Trust.

In June 2009, the CICA amended Section 3862 "Financial Instruments – Disclosures" to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. The Trust adopted this standard prospectively effective December 31, 2009. The adoption of this amended standard did not have a material impact on the consolidated financial statements of the Trust.

Effective July 1, 2009, the Trust prospectively adopted the CICA amended section 3855, "Financial Instruments – Recognition and Measurement", in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and, provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The Trust adopted this standard prospectively effective December 31, 2009. The adoption of this amended standard did not have a material impact on the consolidated financial statements of the Trust.

Future Accounting Changes

In January 2009, the CICA issued Section 1582 "Business Combinations" which establishes principles and requirements of the acquisition method for business combinations and related disclosures. The purchase price is to be based on trading data at the closing date of the acquisition, not the announcement date of the acquisition, and most acquisition costs are to be expensed as incurred. This standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2011. The adoption of this standard may have an impact on the Trust's accounting of future business combinations.

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" which establishes standards for the preparation of consolidated financial statements and Section 1602 "Non-controlling Interests" which provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The Trust plans to adopt this standard prospectively effective January 1, 2011. The adoption of this standard may have an impact on the Trust's accounting of future business combinations.

International Financial Reporting Standards ("IFRS")

In October 2009, the Accounting Standards Board ("AcSB") issued a third IFRS Omnibus Exposure Draft confirming that IFRS will replace Canadian GAAP for financial periods beginning on January 1, 2011. At the transition date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Baytex for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

Throughout 2009 the Trust has assessed the impact of adopting IFRS and is continuing to implement plans for transition. The key elements include analyzing accounting policy alternatives, process changes, internal control requirements and information system changes.

Management has not yet finalized its accounting policies and as such is unable to quantify the impact on the financial statements of adopting IFRS. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to the Trust's adoption of IFRS, Management's plan is subject to change based on new facts and circumstances that arise after the date of this MD&A.

First-Time Adoption of IFRS

IFRS 1, "First-Time Adoption of International Financial Reporting Standards" ("IFRS 1"), provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for Baytex. At this time, the Trust anticipates it will apply the following exemptions:

Property, plant and equipment ("PP&E") – 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.

Business combinations – IFRS 1 permits the use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Share-based payments – IFRS 1 provides an exemption on IFRS 2, "Share-Based Payments" to equity instruments which vested before the Trust's transition date to IFRS.

Cumulative translation differences – An option is available to deem cumulative translation differences on all foreign operations as zero at the date of transition.

Key Accounting Policy Differences

The transition from Canadian GAAP to IFRS is significant and may materially affect our reported financial position and results of operations. At this time, Baytex has identified key differences that will impact the financial statements as follows:

Exploration and Evaluation ("E&E") expenditures – On transition to IFRS Baytex will re-classify all E&E expenditures that are currently included in the PP&E balance on the consolidated balance sheet. This will consist of the book value of undeveloped land that relates to exploration properties. Baytex will initially capitalize these costs as E&E assets on the balance sheet. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist.

Depletion expense – Under IFRS, costs will be depleted on a unit of production basis at a more granular level than the country level. The Trust has the option to base the depletion calculation using either total proved or proved plus probable reserves. Baytex has not concluded at this time which method it will use.

Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash generating unit level using either total proved or proved plus probable reserves. Impairment losses are reversed under IFRS when there is an increase in the recoverable amount.

Due to the recent withdrawal of the exposure draft on IAS 12 Income Taxes in November 2009 and the issuance of the exposure draft on IAS 37 Provisions, Contingent Liabilities and Contingent Assets in January 2010, Management is still determining the impact of these revised standards on its IFRS transition.

Internal Controls Over Financial Reporting and Disclosure Controls and Procedures

During 2010, the Trust will continue to assess the impact of the adoption of IFRS on internal controls over financial reporting to ensure all changes in accounting polices include appropriate additional controls and procedures for future IFRS reporting requirements.

In regards to disclosure controls and procedures, Baytex will be assessing stakeholders' information requirements and ensure that appropriate and timely information is provided once available.

Information Technology Systems

As a result of Baytex's evaluation of our Information Technology systems, modifications have been made to the accounting systems to accommodate the additional requirements under IFRS. The modifications were not significant, however, deemed critical in order to allow for reporting of both Canadian GAAP and IFRS financial statements in 2010. Additional system modifications may be required based on final accounting policy choices.

TRUST INFORMATION

The Trust is authorized to issue an unlimited number of trust units. As at March 10, 2010, the Trust had 110,367,157 trust units issued and outstanding.

At March 10, 2010, the Trust had a principal amount of $7.1 million of convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit. The convertible debentures mature on December 31, 2010, at which time they are due and payable.

Effective August 29, 2008, all of the outstanding exchangeable shares were purchased by Baytex ExchangeCo Ltd. for consideration of 1.79560 trust units for each exchangeable share.

SELECTED ANNUAL INFORMATION

($ thousands, except per unit amounts)	2009	2008	2007
Petroleum and natural gas sales	789,820	1,159,718	745,885
Net income(1)	87,574	259,894	132,860
Per unit basic(1)	0.83	2.83	1.66
Per unit diluted(1)	0.82	2.74	1.60
Total assets	1,884,005	1,812,333	1,407,150
Total long-term financial liabilities	150,000	227,468	190,004
Cash distributions declared per unit	1.56	2.64	2.16

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

Overall production for 2009 was 41,382 boe/d which represented a 3% increase from 40,239 boe/d in 2008 and a 14% increase from 36,222 boe/d in 2007. Average wellhead prices net of blending costs received were $45.00 per boe during 2009, $65.66 per boe during 2008 and $46.53 per boe during 2007.

FOURTH QUARTER 2009

For a discussion and analysis of our operating and financial results for the three months ended December 31, 2009, please see our Management's Discussion and Analysis for the three months and year ended December 31, 2009 dated March 10, 2010, which is incorporated by reference into this MD&A and is accessible on SEDAR at www.sedar.com.

2010 GUIDANCE

Baytex has set a 2010 exploration and development capital budget of $235 million designed to generate production levels at an average annual rate of 43,500 boe/d. Approximately 60% of this budget will be directed towards our heavy oil operations program, with the single largest project being horizontal cold well development at our Seal heavy oil resource play in the Peace River oil sands. The balance of our program will be directed towards our light oil and natural gas operations in Canada and the United States with the largest project being our Bakken/Three Forks light oil development in North Dakota.

ENVIRONMENTAL REGULATION AND RISK

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. 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

The Government of Canada ratified the Kyoto Protocol in 2002, calling for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business as usual" levels by 2012. In December 2009, representatives of approximately 170 countries meet in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The Copenhagen negotiations resulted in the Copenhagen Accord, a non-binding political accord which reinforced the Kyoto Protocol's commitment to reducing greenhouse gas emissions. In response to the Copenhagen Accord, the government of Canada revised its emissions reduction goals and now aims to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. Despite the commitments made under the Kyoto Protocol and the Copenhagen Accord, no federal legislation has been implemented to regulation the emission of greenhouse gases and the Government of Canada has indicated that it will delay the implementation of climate change legislation and regulations in order to ensure consistency with the approach ultimately taken by the United States with respect to greenhouse gas emissions.

There has been much public debate with respect to Canada's ability to meet these targets and the Government of Canada's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The implementation of strategies for reducing greenhouse gases, whether to meet the goals of the Kyoto Protocol, the Copenhagen Accord 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 change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on Baytex and our 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, 2009 under the Industry Conditions section.

The New Royalty Framework

On October 25, 2007, the Alberta government announced the "New Royalty Framework" ("NRF"), which introduced the following changes to Alberta's royalty regime effective January 1, 2009:

- Conventional oil – overall royalty rates increased from the pre-NRF maximum of 30% and 35% for old and new tiers. The NRF rates vary on a sliding scale basis up to 50%, and rate caps have been raised to $120 per barrel for West Texas Intermediate crude.
- Natural gas – the Government eliminated "old" and "new" tiers. Royalty rates, pre-NRF at 5% to 35% increased to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at $17.75 per gigajoule.
- Oil Sands – before NRF, the pre-payout royalty rate was 1%. Under the NRF, this rate increased for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the previous regime, once an oil sands project reached payout, the 1% royalty converted to a 25% net profits interest. Under the NRF, the net profits interest applies at the rate of 25% when oil is less than $55 per bbl of WTI, and increases for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Alberta government announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. Companies drilling new natural gas or conventional oil deep wells between 1,000 and 3,500 metres are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF and wells that operated under the transitional royalty rates will revert to royalty rates determined by the NRF.

On March 3, 2009, the Alberta government announced a new well incentive program intended to stimulate conventional drilling activity. The incentive program offers a one-year royalty credit for conventional oil and gas wells drilled between April 1, 2009 and March 31, 2010 of $200 per metre and also provides for a maximum 5% royalty for all new wells that begin producing conventional oil and gas between during the same period. In June 2009, the Alberta government announced the extension of these incentive programs for until March 31, 2011.

On August 6, 2009, the British Columbia ("B.C.") government announced a stimulus package to boost the current economy by introducing changes to the B.C. royalty program. These changes include a one-year, 2% royalty rate for the first year of production on wells drilled in a 10 month window from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010; a permanent increase of 15% in the existing Deep Royalty Credit Program for both vertical and horizontal wells; and a permanent change in the Deep Royalty Credit Program to include horizontal wells drilled between 1,900 and 2,300 metres, which is shallower than the previous cut-off of 2,300 metres.

Further information regarding NRF and current provincial royalties and incentive programs is contained in our Annual Information Form for the year ended December 31, 2009 under the Industry Conditions section.

Broad-based Federal Tax Reductions

On October 30, 2007, the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the SIFT tax rate to equal the federal corporate income tax rate plus the provincial SIFT tax rate, discussed below.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law amendments to the Income Tax Act (Canada) (the "Tax Act") that will result in the taxation of distributions by certain specified investment flow-through trust entities (a "SIFT"), such as Baytex, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "SIFT Rules"). Currently, the SIFT Rules provide that the SIFT tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax rate. The provincial SIFT Tax rate will be based on the general provincial corporate income tax rate in each province in which the Trust has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable provincial allocation formula will be used. Specifically, the Trust's taxable distributions, if any, will be allocated to provinces by taking half of the aggregate of: (i) that proportion of the Trust's taxable distributions, if any, for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and (ii) that proportion of the Trust's taxable distributions, if any, for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada. The Trust's main permanent establishment is anticipated to be in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011. Taxable distributions, if any, that are not allocated to any province, would instead be subject to a 10% rate constituting the provincial component.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. For the Trust, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of the subsequent three years. On December 4, 2008, the Federal Minister of Finance announced changes to the guidelines discussed above to allow a SIFT to accelerate the utilization of the SIFT annual safe harbour amount for each of 2009 and 2010 so that the safe harbour amounts for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for a SIFT, but it allows a SIFT to use its normal growth room remaining as of December 4, 2008 in a single year, rather than staging a portion of the normal growth room over the 2009 and 2010 years. The Trust did not issue equity in excess of the safe harbour limits during 2006, 2007, 2008 or 2009. The Trust issued $165.9 million equity during the year ended December 31, 2009 resulting in an unused available safe harbour amount of $1,160.7 million as at December 31, 2009.

On July 14, 2008, the Federal Minister of Finance announced proposed amendments to the Tax Act, including technical amendments to clarify certain aspects of the SIFT Rules and to provide rules to facilitate the conversion of existing SIFTs into corporations on a tax-deferred basis (the "Conversion Rules"). The Conversion Rules address many of the principal substantive and administrative issues that arise when structuring a corporate conversion of an income trust under the Tax Act. The Conversion Rules contemplate two alternatives for the conversion of a publicly-traded SIFT into a taxable Canadian corporation and the winding-up of the SIFT's underlying structure. The first alternative involves the winding-up of the SIFT into a taxable Canadian corporation whereas the second approach involves the distribution by the publicly-traded SIFT of shares of an underlying taxable Canadian corporation to its unitholders. The Conversion Rules will generally only apply to the winding-up of a SIFT or a distribution of shares completed after July 14, 2008 and before 2013. Bill C-10, which received Royal Assent on March 12, 2009, contained legislation implementing the Conversion Rules. We are planning to complete a conversion transaction from the current trust structure to a corporate legal form to be completed before the end of 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

Disclosure Controls and Procedures

As of December 31, 2009, an evaluation was conducted of the effectiveness of the Trust'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")) by management, with the participation of 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 Trust's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust 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 Trust'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 Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Trust'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.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. "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 that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management has assessed the effectiveness of the Trust's internal control over financial reporting as of December 31, 2009. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2009. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2009 has been audited by Deloitte & Touche LLP, as reflected in their report for 2009.

No changes were made to our internal control over financial reporting during the year ended December 31, 2009, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex'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", "on-going", "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: our ability to maintain production levels by investing approximately half of our funds from operations into exploration and development activities; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; our ability to fund our capital expenditures and distributions on our trust units from funds from operations; the sufficiency of our capital resources to meet our on-going short, medium and *long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; funding sources for our cash distributions and capital program; the timing of funding our financial obligations; the impact of the adoption of new accounting standards on our financial statements; the impact of the adoption of IFRS on our financial position and results of operations; our exploration and development capital program for 2010 and the allocation thereof to various projects; our average production rate for 2010; the impact of environmental and climate change regulations on our operations; the taxation of income trusts; and potential changes to our business form. 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 distributions 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 Baytex's Annual Information Form, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2009, 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.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.