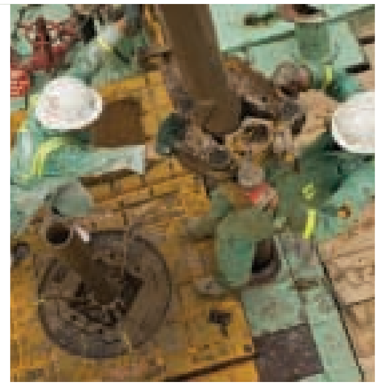
BAYTEX

ENERGY TRUST



Q3

2009

HIGHLIGHTS

- Generated funds from operations of $88.8 million ($92.2 million before deducting $3.4 million of transaction costs relating to the issuance of long-term notes during the quarter) an increase of 2% (6% before transaction costs for long-term notes issuance) over the prior quarter or $0.83 per basic unit ($0.86 per basic unit before transaction costs for long-term notes issuance) for the third quarter of 2009;
- Produced an average of 42,623 boe/d in the quarter, a record quarterly production level, and an increase of 6% over Q2/09;
- Completed an acquisition of predominantly heavy oil assets at accretive metrics with current production of approximately 3,000 boe/d for a net purchase price of $86.5 million;
- Reached agreement to pre-pay the remaining deferred acquisition payments for our Bakken-Three Forks lands in North Dakota subsequent to the end of the third quarter, providing greater and accelerated operating control as we continue to develop this light oil resource play;
- Issued $150 million in senior unsecured debentures, and redeemed US$180 million of senior subordinated notes; and
- Delivered total market return (assuming reinvestment of distributions) of 22.4% in the third quarter (73.1% for nine months ended September 30, 2009).

	Three Months Ended			Nine Months Ended	
	September 30, 2009	June 30, 2009	September 30, 2008	**September 30, 2009**	September 30, 2008
FINANCIAL *(thousands of Canadian dollars, except per unit amounts)*					
Petroleum and natural gas sales	**208,229**	192,667	363,044	**551,839**	959,828
Funds from operations(1)	**88,809**	86,661	146,586	**234,842**	373,351
Per unit – basic	**0.83**	0.82	1.53	**2.26**	4.16
Per unit – diluted	**0.80**	0.81	1.47	**2.23**	3.94
Cash distributions declared	**32,799**	32,569	57,233	**100,315**	141,712
Per unit	**0.36**	0.36	0.75	**1.14**	1.96
Net income	**40,657**	27,451	137,228	**59,618**	207,493
Per unit – basic	**0.38**	0.26	1.44	**0.57**	2.31
Per unit – diluted	**0.37**	0.26	1.39	**0.57**	2.23
Exploration and development	**36,477**	30,278	48,584	**114,419**	142,114
Acquisitions – net of dispositions	**93,662**	2,348	78,635	**95,994**	256,925
Total capital expenditures	**130,139**	32,626	127,219	**210,413**	399,039
Long-term notes	**150,000**	209,187	190,725	**150,000**	190,725
Bank loan	**272,918**	154,171	200,445	**272,918**	200,445
Convertible debentures	**8,799**	10,053	10,377	**8,799**	10,377
Working capital deficiency	**34,536**	38,500	56,446	**34,536**	56,446
Total monetary debt(2)	**466,253**	411,911	457,993	**466,253**	457,993

	Three Months Ended			Nine Months Ended	
	September 30, 2009	June 30, 2009	September 30, 2008	**September 30, 2009**	September 30, 2008
OPERATING					
Daily production					
Light oil & NGL (bbl/d)	**7,021**	7,073	8,377	**7,071**	7,498
Heavy oil (bbl/d)	**25,532**	23,284	24,078	**24,090**	23,159
Total oil (bbl/d)	**32,553**	30,357	32,455	**31,161**	30,657
Natural gas (MMcf/d)	**60.4**	60.2	60.5	**58.6**	53.9
Oil equivalent (boe/d @ 6:1)(3)	**42,623**	40,387	42,538	**40,934**	39,635
Average prices (before hedging)					
WTI oil (US$/bbl)	**68.18**	59.51	118.36	**56.98**	113.43
Edmonton par oil ($/bbl)	**71.70**	58.26	122.66	**62.79**	115.93
BTE light oil & NGL ($/bbl)	**57.50**	54.28	107.41	**51.63**	100.66
BTE heavy oil ($/bbl)(4)	**55.12**	51.19	84.65	**47.11**	74.63
BTE total oil ($/bbl)	**55.64**	51.91	90.56	**48.15**	80.94
BTE natural gas ($/Mcf)	**3.42**	3.85	8.01	**4.18**	8.23
BTE oil equivalent ($/boe)	**47.27**	44.78	80.44	**42.61**	73.84
USD/CAD noon rate at period end	**0.9327**	0.8602	0.9435	**0.9327**	0.9435
USD/CAD average rate for period	**0.9113**	0.8568	0.9600	**0.8547**	0.9818
TRUST UNIT INFORMATION					
TSX					
Unit price (Cdn$)					
High	**$ 25.35**	$ 20.18	$ 35.01	**$ 25.35**	$ 35.37
Low	**$ 17.80**	$ 14.89	$ 23.15	**$ 9.77**	$ 16.30
Close	**$ 23.60**	$ 19.59	$ 25.73	**$ 23.60**	$ 25.73
Volume traded (thousands)	**24,885**	25,453	31,620	**89,326**	92,150
NYSE					
Unit price (US$)					
High	**$ 23.69**	$ 18.42	$ 35.20	**$ 23.69**	$ 35.20
Low	**$ 15.20**	$ 11.76	$ 22.35	**$ 7.84**	$ 15.88
Close	**$ 22.04**	$ 16.83	$ 24.71	**$ 22.04**	$ 24.71
Volume traded (thousands)	**5,778**	9,426	10,240	**27,748**	20,016
Units outstanding (thousands)	**107,777**	106,988	96,934	**107,777**	96,934

(1) Funds from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future distributions and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months and nine months ended September 30, 2009.

(2) 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 value of the convertible debentures.

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

(4) Heavy oil wellhead prices are net of blending costs.

Forward-Looking Statements

This Report contains forward-looking statements relating to: our production levels for the fourth quarter of 2009; development plans for our properties; our exploration and development capital expenditures for 2009; the amount of deferred acquisition payments for the North Dakota acquisition to be paid in 2009; our liquidity and financial capacity; oil and gas prices and differentials between light, medium and heavy oil prices; the demand for and supply of crude oil; the development of refining and transportation infrastructure; and our ability to fund cash distributions and our capital program from internally-generated cash flow. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

MESSAGE TO UNITHOLDERS

Operations Review

Capital expenditures for exploration and development activities totaled $36.5 million for the third quarter of 2009. During this quarter, Baytex participated in the drilling of 33 (27.8 net) wells, resulting in 31 (26.8 net) oil wells and two (1.0 net) service wells, for a 100% success rate. Third quarter drilling included 20 (17.4 net) oil wells in the Lloydminster area, eight (8.0 net) oil wells at Seal, three (1.4 net) oil wells in the United States, and two (1.0 net) service (air injection) wells in a non-operated project at Kerrobert.

Baytex closed the acquisition of certain oil and gas assets located primarily in the Kerrobert and Coleville areas of Saskatchewan on July 30, 2009. The predominantly heavy oil assets have performed as expected, with production of approximately 3,000 boe/d since closing (contributing approximately 2,000 boe/d to average production in the third quarter).

Production averaged 42,623 boe/d during the third quarter of 2009, as compared to 40,387 boe/d in the second quarter. Production was slightly above guidance of approximately 42,000 boe/d for the third quarter of 2009. We expect production to be approximately 42,500 to 43,000 boe/d in the fourth quarter of 2009.

Heavy oil production from Seal averaged approximately 5,200 boe/d in the third quarter. Eight wells were drilled in the Seal area in the third quarter, increasing the total number of horizontal producing wells in the Seal area to 58 and continuing Baytex's record of 100% drilling success. We anticipate drilling approximately four more horizontal wells at Seal during the fourth quarter. In addition, we plan to drill approximately eight more heavy oil wells in the Lloydminster area during the remainder of the year.

In our Bakken-Three Forks project in North Dakota, we drilled two Baytex-operated horizontal oil wells (37.5% working interest) and subsequently applied multi-stage fracture treatments to both wells. Production from the first well averaged approximately 300 barrels of oil per day during the peak thirty days of production, exceeding our previous model for this play by one-third. The second well is in the early stages of production testing. We are continuing our drilling program with three more Bakken-Three Forks wells in the fourth quarter. Subsequent to the end of the quarter, we reached an agreement with our partner in this project, a private company, to pre-pay our remaining deferred acquisition payments for the land position we acquired in July 2008. Under the terms of the pre-pay agreement, Baytex will pay US$33.2 million to complete our remaining obligations, which would otherwise have totaled US$36 million over approximately the next five to six quarters. In addition, Baytex will be assigned an operating area corresponding to approximately 38% of the lands in the project area, an expansion of eleven operated sections from the operating area designated in the July 2008 agreement. In addition to decreasing the cost of the remaining land payments, the purpose of the pre-pay is to increase our degree of operating control in this large light oil resource play. Closing of the pre-pay agreement is expected to occur in mid-December, with assumption of the operating area at the beginning of 2010.

We continue to develop our Viking light oil resource play on lands in Alberta, following up on a successful well drilled in the second quarter which averaged approximately 90 barrels of oil per day during the peak thirty days of production. Subsequent to the end of the third quarter, we drilled and tested an additional well in the Viking in Alberta. This well will be placed on production during the fourth quarter, with production rates expected to be comparable to or better than those from the well drilled in the second quarter. We plan to drill up to four additional Viking wells in the fourth quarter.

We drilled our first horizontal well in our Mowry Shale play in Wyoming in the third quarter, with completion planned for the fourth quarter.

Consistent with previous guidance, full-year exploration and development capital expenditures are estimated to be $165 million. Total deferred acquisition payments for our North Dakota properties will be US$39.2 million, including the pre-pay of our remaining deferred land acquisition payments. In the absence of any other fourth quarter transactions, we project total acquisition capital expenditures of $133 million for 2009 (including expenditures for both the North Dakota and the Saskatchewan acquisitions).

Financial Review

During the third quarter of 2009, we completed a refinancing transaction to redeem our U.S. notes maturing in 2010 and to extend the maturity of our long-term debt. In August, we issued $150 million of 9.15%, 7-year (non-call 3) debentures at par in the emerging Canadian high yield market. This issue was one of very few placed in the Canadian market to-date, and was very well received, with a yield which was lower than prevailing rates in the U.S. high yield market. The proceeds of this issue were used to partially fund the third-quarter redemption of our US$180 million senior unsecured notes which were due to mature in July 2010. At the time of this redemption, we converted an equivalent amount of borrowings on our credit facility from Canadian to U.S. dollars in order to maintain the natural currency hedge and currency exposure provided by U.S. dollar denominated debt. Finally, we entered into a series of interest rate swaps with the result that our interest rate exposure is floating for the next two years, and the large majority of our exposure is fixed for years three to five forward, locking in relatively low costs of borrowing, and limiting our exposure to increases in future interest rates.

The third quarter asset acquisition was funded entirely through draws on our credit facility. At the end of the third quarter, total monetary debt was $466 million, which offers us undrawn credit facilities of over $200 million and represents a debt-to-cash flow ratio of 1.3 times based on annualized third quarter 2009 cash flow. Both of these metrics are well within our leverage and liquidity targets, and provide ample capacity to finance our operations going forward.

Funds from operations for the third quarter of 2009 was $88.8 million, which was a 2% increase over second quarter results. Third quarter revenue growth from improving commodity prices and increased sales volumes were partially offset by increased royalties and financing charges. As compared to the second quarter cash flow, several non-recurring items contributed to the quarter over quarter increase in expense items. First, the second quarter results included positive royalty and G&A adjustments of $3.3 million which were not repeated in the third quarter. Secondly, third quarter results were impacted by a one time payment of $3.4 million in transaction costs on the issuance of $150 million of senior unsecured debentures. Lastly, the third quarter results included several non-recurring operating expense items which in aggregate added approximately $1.0 million to third quarter operating costs. These payments relate to charges incurred by previous owners on acquired properties.

The third quarter saw continued improvement in world oil prices as the average WTI price for the quarter was US$68.18 per bbl, a 15% increase over the second quarter. The benefit of this improvement was partially offset for Canadian producers by the quarter over quarter weakening of the U.S. dollar relative to the Canadian dollar. Heavy oil pricing continued to be very strong, with third quarter differentials, as measured by market pricing for Lloyd Blend, averaging 15% of WTI for the third quarter of 2009. Baytex heavy oil pricing averaged $55.12 per bbl, an increase of 8% over the $51.19 per bbl realized in the second quarter. The near term outlook for heavy oil pricing continues to be favorable, supported by third party investment in refining and transportation infrastructure, including the looming commencement of oil shipments on the Keystone pipeline. We are pleased to see the development of additional transportation infrastructure which will enhance access to new markets for Canadian producers and, we believe, support the continuation of a strong heavy oil pricing environment. Capitalizing on the strength of near term heavy oil pricing, Baytex recently entered into a series of forward agreements which will result in sales of 1,000 barrels per day of blend for 2010 at a heavy oil price of over $68 per bbl, or $13 per bbl higher than our third quarter 2009 realized heavy oil price. Natural gas pricing continued to be weak, with our third quarter wellhead price averaging $3.42 per Mcf as compared to $3.85 per Mcf in the second quarter. Looking forward, Baytex has mitigated its exposure to weaker natural gas prices by hedging approximately 45% of its projected net of royalty natural gas sales for 2010.

Total cash distributions declared in the quarter of $32.8 million, or $0.36 per unit, represented a payout ratio of 37% net of distribution reinvestment plan (“DRIP”) participation (44% before DRIP). This conservative payout ratio is consistent with our philosophy of sustainability and has contributed to our strong financial position, while maintaining a meaningful income stream to our unitholders.

Staff Appointment

Brian Ector has joined Baytex as Director of Investor Relations. Mr. Ector has fifteen years of experience as a research analyst covering both energy trusts and exploration and production corporations. He spent the last seven years with Scotia Capital where he was highly regarded for his definitive reports and insightful valuation perspectives, and where he consistently ranked as one of the top rated analysts in Canada. Brian is a graduate of the University of Calgary and received his CFA designation in 1996.

On behalf of the Board of Directors,

Anthony Marino
President and Chief Executive Officer
November 10, 2009

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 three months and nine months ended September 30, 2009. This information is provided as of November 9, 2009. The third quarter results have been compared with the corresponding period in 2008. This MD&A should be read in conjunction with the Trust's unaudited interim consolidated comparative financial statements for the three months and nine months ended September 30, 2009 and 2008 and our audited consolidated comparative financial statements for the years ended December 31, 2008 and 2007, together with accompanying notes, and the Annual Information Form for the year ended December 31, 2008 (the "AIF"). These documents and additional information about the Trust are 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 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 generated from operating activities before changes in non-cash working capital, site restoration and reclamation expenditures, deferred charges and other assets. 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 value of the convertible debentures.

Economic Environment

The current economic environment outlook continues to show signs of recovery from the recent financial crisis. Sustaining the recent improvement in commodity 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 key business objectives of preserving balance sheet strength and liquidity, maintaining and, where possible, profitably expanding the productive capacity of the Trust and delivering a sustainable distribution to our unitholders.

Production

Production for the three months ended September 30, 2009 totaled 42,623 boe/d compared to 42,538 boe/d for the same period in 2008. Light oil and natural gas liquids ("NGL") production for the third quarter of 2009 decreased by 16% to 7,021 bbl/d from 8,377 bbl/d in the third quarter of 2008. Heavy oil production for the third quarter of 2009 increased by 6% to 25,532 bbl/d from 24,078 bbl/d for the same period last year. Natural gas production was 60.4 MMcf/d for the third quarter of 2009, as compared to 60.5 MMcf/d for the same period last year.

Total production for the nine months ended September 30, 2009 was 40,934 boe/d, a 3% increase from the nine months ended September 30, 2008. For the first nine months of 2009, light oil and NGL production decreased by 6% to 7,071 bbl/d from 7,498 bbl/d for the same period last year. Heavy oil production for the first nine months in 2009 increased by 4% to 24,090 bbl/d compared to 23,159 bbl/d for the same period in 2008. Natural gas production increased by 9% to 58.6 MMcf/d for the first nine months in 2009 compared to 53.9 MMcf/d for the same period in 2008.

Revenue

Petroleum and natural gas sales decreased 43% to $208.2 million for the third quarter of 2009 from $363.0 million for the same period in 2008. For the per sales unit calculations, heavy oil sales for the three months ended September 30, 2009 were 382 bbl/d lower (three months ended September 30, 2008 – 204 bbl/d lower) than the production for the period due to changes in inventory. The corresponding number for the nine months ended September 30, 2009 was a decrease of 215 bbl/d (nine months ended September 30, 2008 – an increase of 284 bbl/d).

Revenue from light oil and NGL for the third quarter of 2009 decreased 55% from the same period a year ago due to a 46% decrease in wellhead prices and a 16% decrease in sales volume. Revenue from heavy oil decreased 31% despite a 5% increase in sales volume, as wellhead prices decreased by 35%. Revenue from natural gas decreased 57% due entirely to the decrease in wellhead prices while sales volumes remained consistent.

	Three Months Ended			
	September 30, 2009		September 30, 2008	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue				
Light oil & NGL	**37,141**	**57.50**	82,786	107.41
Heavy oil(2)	**127,544**	**55.12**	185,914	84.65
Total oil revenue	**164,685**	**55.64**	268,700	90.56
Natural gas revenue	**19,023**	**3.42**	44,578	8.01
Total oil and gas revenue	**183,708**	**47.27**	313,278	80.44
Sulphur revenue	**118**		3,306	
Other income	**22**		–	
Sales of heavy oil blending diluent	**24,381**		46,460	
Total petroleum and natural gas sales	**208,229**		363,044	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

For the first nine months of 2009, light oil and NGL revenue decreased 52% from the same period last year due to a 49% decrease in wellhead prices while sales volumes decreased 6%. Revenue from heavy oil decreased 36% due to a 37% decrease in wellhead prices partially offset by a 4% increase in production. Revenue from natural gas decreased 45% as the 9% increase in production was more than offset by a 49% decrease in wellhead prices.

	Nine Months Ended			
	September 30, 2009		September 30, 2008	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue				
Light oil & NGL	99,661	51.63	206,813	100.66
Heavy oil(2)	307,087	47.11	479,377	74.63
Total oil revenue	406,748	48.15	686,190	80.94
Natural gas revenue	66,930	4.18	121,503	8.23
Total oil and gas revenue	473,678	42.61	807,693	73.84
Sulphur revenue	706		5,960	
Other income	58		2,000	
Sales of heavy oil blending diluent	77,397		144,175	
Total petroleum and natural gas sales	551,839		959,828	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

During the current quarter, sulphur production averaged 55.2 tonnes per day with an average price of $23 per tonne, as compared to 53.5 tonnes per day with an average price of $672 per tonne in the same period last year. For the nine months ended September 30, 2009, sulphur production averaged 50.0 tonnes per day with an average price of $52 per tonne, as compared to 40.6 tonnes per day with an average price of $536 per tonne in the same period in 2008.

Financial Instruments

The gain on financial instruments for the third quarter was $23.6 million, as compared to a gain of $66.7 million in the third quarter of 2008. This is comprised of $20.3 million and $3.3 million in realized and unrealized gains, respectively, for the third quarter of 2009 as compared to $22.3 million in realized loss and $89.0 million in unrealized gain in the third quarter of 2008.

The gain on financial instruments for the nine months ended September 30, 2009 was $20.3 million compared to a $24.5 million loss for the same period in 2008. This is comprised of $65.9 million in realized gain and $45.6 million in unrealized loss for the first nine months of 2009 compared to $57.9 million in realized loss and $33.4 million in unrealized gain in the same period one year ago.

Royalties

Total royalties decreased to $40.0 million for the third quarter of 2009 from $72.8 million in the same period last year. Royalties for the current quarter related to the production of sulphur were immaterial.

Total royalties for the third quarter of 2009 were 21.8% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent, and other), as compared to 23.0% for the same period in 2008. For the third quarter of 2009, royalties were 24.1% of sales for light oil, NGL and natural gas, as compared to 23.0% for the third quarter of 2008. Royalties for heavy oil were 20.8% of sales (excluding sales of heavy oil blending diluent, and other) for the third quarter of 2009, as compared to 23.0% for the third quarter of 2008. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and well productivity increase. The overall decrease in royalty rates was due to lower pricing.

For the nine months ended September 30, 2009, royalties decreased to $90.3 million from $175.8 million for the same period last year. Total royalties for the first nine months of 2009 were 19.0% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent, and other), as compared to 21.6% for the corresponding period a year ago. For the first nine months of 2009, royalties were 20.3% of revenue for light oil, NGL and natural gas (2008 – 23.2%) and 18.4% for heavy oil (excluding sales of heavy oil blending diluent, and other) (2008 – 20.6%).

Operating Expenses

Operating expenses for the third quarter of 2009 decreased to $40.2 million from $46.4 million in the corresponding quarter last year. This reduction in costs was in spite of several non-recurring items which in aggregate added approximately $1.0 million to operating costs during the third quarter. These payments relate to charges incurred by previous owners on acquired properties. Operating expenses for the current quarter include $0.1 million related to the production of sulphur, which was the same as for the third quarter in 2008. Operating expenses were $10.35 per boe for the third quarter of 2009 compared to $11.91 per boe for the third quarter of 2008. For the third quarter of 2009, operating expenses were $10.68 per boe of light oil, NGL and natural gas, and $10.09 per barrel of heavy oil, as compared to $10.93 and $12.63, respectively, for the third quarter of 2008. In the case of heavy oil, the reduction in per barrel expense resulted from higher production levels and reductions in the cost of energy and services inputs.

Operating expenses for the nine months ended September 30, 2009 decreased to $118.5 million from $125.1 million for the first nine months of 2008. Operating expenses were $10.66 per boe for the nine months ended September 30, 2009 compared to $11.44 per boe for the corresponding period of the prior year. For the first nine months of 2009, operating expenses were $11.31 per boe of light oil, NGL and natural gas and $10.17 per barrel of heavy oil, as compared to $11.25 and $11.53, respectively, for the same period a year earlier. The variance in operating expenses per unit results from the same factors noted above.

Transportation and Blending Expenses

Transportation and blending expenses for the third quarter of 2009 was $36.5 million compared to $57.1 million for the third quarter of 2008. Transportation expenses for the current quarter included $0.3 million related to the transportation of sulphur, which was consistent with the third quarter in 2008. Transportation expenses before blending costs were $3.04 per boe for the third quarter of 2009 compared to $2.65 per boe for the same period of 2008. Transportation expenses were $0.61 per boe of light oil, NGL and natural gas and $4.68 per barrel of heavy oil in the third quarter of 2009 as compared to $0.70 and $4.16, respectively, for the same period of 2008. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal.

Transportation and blending expenses for the nine months ended September 30, 2009 were $113.4 million compared to $173.0 million for the first nine months of 2008. Transportation expenses for the nine months ended September 30, 2009 include $0.9 million related to the production of sulphur, which was consistent with the same period in 2008. Transportation expenses before blending costs were $3.15 per boe for the first nine months of 2009 compared to $2.55 for the same period in 2008. Transportation expenses were $0.62 per boe of light oil, NGL and natural gas and $4.94 per barrel of heavy oil in the 2009 period, compared to $0.70 and $3.85, respectively, for the same period in 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. In the third quarter of 2009, the blending cost was $24.4 million for the purchase of 3,559 bbl/d of condensate at $74.47 per barrel, as compared to $46.5 million for the purchase of 3,909 bbl/d at $129.18 per barrel for the same period last year. The cost of diluent is effectively recovered in the sale price of a blended product. For the nine months ended September 30, 2009, the blending cost was $77.4 million for the purchase of 4,206 bbl/d of condensate at $67.40 per barrel as compared to $144.2 million for the purchase of 4,228 bbl/d at $124.45 per barrel in the same period last year.

General and Administrative Expenses

General and administrative expenses for the third quarter of 2009 decreased to $6.7 million from $7.1 million a year earlier. On a per sales unit basis, these expenses were $1.72 per boe for the third quarter of 2009 compared to $1.82 per boe for the third quarter of 2008. The majority of the decrease was due to higher operating overhead recoveries.

General and administrative expenses for the nine months ended September 30, 2009 were $22.1 million, compared to $22.0 million for the same period in 2008. On a per sales unit basis, these expenses were $1.99 per boe in the nine months ended September 30, 2009 and $2.01 per boe in the nine months ended September 30, 2008. In accordance with our full cost accounting policy, no general and administrative expenses were capitalized in either 2009 or 2008.

Unit-based Compensation Expense

Compensation expense related to Baytex's trust unit rights incentive plan was $1.7 million for the third quarter of 2009 compared to $2.0 million for the third quarter of 2008. For the nine months ended September 30, 2009, compensation expense was $4.8 million compared to $6.2 million for the same period in 2008.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Interest Expense

Interest expense for the third quarter of 2009 increased by $5.5 million to $13.7 million compared to $8.2 million in the same quarter last year. The majority of the increase is due to $1.3 million of interest and $3.4 million of transaction costs related to $150 million senior unsecured debentures issued on August 26, 2009. This increase is partially offset by a $0.7 million decrease due to lower interest rates on our bank loan.

Interest expense for the nine months ended September 30, 2009 increased by $6.3 million to $31.4 million compared to $25.1 million for the same period in 2008. The majority of the increase is due to $1.3 million of interest and $3.4 million of transaction costs related to $150 million senior unsecured debentures issued on August 26, 2009. This increase is offset by a $3.0 million decrease due to lower interest rates on our bank loan. A commitment fee of $1.8 million was incurred in 2009 to amend and extend the credit facility.

Foreign Exchange

Foreign exchange gain in the third quarter of 2009 was $11.1 million compared to a loss of $7.1 million in the third quarter of 2008. The gain is comprised of an unrealized foreign exchange loss of $10.9 million and a realized foreign exchange gain of $22.0 million. The loss for the same period in 2008 was comprised of an unrealized foreign exchange loss of $7.3 million and a realized foreign exchange gain of $0.2 million. The current quarter's unrealized loss is based on the transition of year to date unrealized gains into realized gains upon the redemption of the US$ senior subordinated notes on September 25, 2009. The prior period loss is based on the translation of US$ senior subordinated notes at 0.9435 at September 30, 2008 compared to 0.9817 at June 30, 2008. The realized foreign exchange gain in the three months ended September 30, 2009 is primarily due to the redemption of the US$ senior subordinated notes.

Foreign exchange gain for the nine months ended September 30, 2009 was $19.4 million compared to a loss of $12.9 million in the prior year. A major component of the realized gain for the nine months ended September 30, 2009 is the gain of $23.7 million realized on redemption of the US$ senior subordinated notes ($nil for 2008). The loss for the nine months ended September 30, 2008 is based on the translation of the US$ senior subordinated notes at 0.9435 at September 30, 2008 compared to 1.0120 at December 31, 2007.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion for the third quarter of 2009 decreased to $58.6 million from $61.3 million for the same quarter in 2008. On a sales-unit basis, the provision for the current quarter was $15.09 per boe compared to $15.73 per boe for the same quarter in 2008.

Depletion, depreciation and accretion increased to $170.2 million for the first nine months of 2009 compared to $162.6 million for the same period last year. On a sales-unit basis, the provision for the current period was $15.31 per boe compared to $14.87 per boe for the same period a year earlier. The increase is attributable to a higher capital base due to the acquisition of the southwest Saskatchewan assets on July 30, 2009.

Taxes

Current tax expense of $2.9 million for the third quarter of 2009 is comprised entirely of Saskatchewan resource surcharge. Current tax expense for the same period a year ago was $3.2 million and was comprised of Saskatchewan resource surcharge and capital tax. Current tax expense of $7.4 million for the nine months ended September 30, 2009 is $1.0 million lower than the $8.4 million recorded for the same period in 2008. The decrease in current tax expense in both the three months and nine months ended September 30, 2009 is attributable to lower resource revenues compared to the three months and nine months ended September 30, 2008.

For the third quarter of 2009, future tax expense totaled $1.9 million compared to an expense of $26.0 million for the same period in 2008. As at September 30, 2009, total future tax liability of $190.9 million (December 31, 2008 – $217.8 million) consisted of a $0.5 million current future tax asset (December 31, 2008 – $nil), $1.3 million long-term future tax asset (December 31, 2008 – $nil), $10.4 million current future tax liability (December 31, 2008 – $25.4 million) and a $182.3 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.

Net Income

Net income for the third quarter of 2009 was $40.7 million compared to net income of $137.2 million for the third quarter in 2008. Revenues, net of royalties decreased $122.0 million or 42% in the third quarter of 2009 compared to the three months ended September 30, 2008. This decrease is further augmented by a $43.1 million reduction in gain on financial instruments in the third quarter of 2009 compared to the third quarter of 2008. The overall $165.0 million decrease in net revenues was offset by reduced transportation and blending costs of $20.6 million, an increase in foreign exchange gain of $18.2 million and a reduction in future tax expense of $24.0 million for the third quarter in 2009 compared to the same period in 2008.

Net income for the nine months ended September 30, 2009 was $59.6 million compared to $207.5 million for the same period in 2008. Revenues, net of royalties, decreased $322.5 million or 41% for the nine months ended September 30, 2009 compared to the same period in 2008. This decrease is attributable to lower commodity prices. This decrease is partially offset by an increase in financial instrument gain of $44.8 million for the first nine months of 2009 compared to the same period in 2008. Other factors that offset the decrease in revenues, net of royalties, included a $59.6 million decrease in transportation and blending expenses, a $32.4 million increase in foreign exchange gain and a $39.4 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 (USD/CAD 0.9327), while revenues and expenses are translated using the average exchange rate for the three month and nine month periods ended September 30, 2009 (USD/CAD 0.9113 and 0.8547, respectively). Translation gains and losses are deferred and included in other comprehensive income in unitholders' equity 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 and a reduction of $9.7 million were recognized in the first, second and third quarters of 2009, respectively, resulting in a balance of $0.7 million in accumulated other comprehensive loss at September 30, 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):

($ thousands)	Three Months Ended September 30, 2009	Three Months Ended June 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Years Ended December 31, 2008	Years Ended December 31, 2007
Cash flow from operating activities	$72,355	$83,525	$150,815	$191,936	$372,830	$471,237	$286,450
Change in non-cash working capital	16,215	2,813	(4,591)	41,882	(229)	(38,896)	(5,140)
Asset retirement expenditures	228	311	351	990	718	1,443	2,442
Decrease (increase) in deferred charges and other assets	11	12	11	34	32	39	2,278
Funds from operations	$88,809	$86,661	$146,586	$234,842	$373,351	$433,823	$286,030
Cash distributions declared	$32,799	$32,569	$ 57,233	$100,315	$141,712	$197,026	$145,927
Payout ratio	37%	38%	39%	43%	38%	45%	51%

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and 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 $32.8 million for the third quarter of 2009 were funded through funds from operations of $88.8 million.

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

($ thousands)	Three Months Ended September 30, 2009	Three Months Ended June 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Years Ended December 31, 2008	Years Ended December 31, 2007
Cash flow from operating activities	$72,355	$83,525	$150,815	$191,936	$372,830	$471,237	$286,450
Cash distributions declared	32,799	32,569	57,233	100,315	141,712	197,026	145,927
Excess of cash flow from operating activities over cash distributions declared	39,556	50,956	93,582	91,621	231,118	274,211	140,523
Net income	40,657	27,451	137,228	59,618	207,493	259,894	132,860
Cash distributions declared	32,799	32,569	57,233	100,315	141,712	197,026	145,927
Excess (shortfall) of net income over cash distributions declared	$ 7,858	$ (5,118)	$ 79,995	$ (40,697)	$ 65,781	$ 62,868	$ (13,067)

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 for acquisitions, it is possible that internally generated cash flow 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 September 30, 2009, Baytex had approximately $206 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 three months ended September 30, 2009, the Trust's net income exceeded cash distributions declared by $7.9 million, with net income reduced by $31.7 million for non-cash items. For the nine months ended September 30, 2009, the Trust's cash distributions exceeded net income by $40.7 million, with net income reduced by $132.3 million for non-cash items. Non-cash charges such as depletion, depreciation and accretion are not 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 ongoing 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 September 30, 2009, total monetary debt was $466.3 million compared to $533.0 million at the end of 2008. Bank borrowings and working capital deficiency at September 30, 2009 was $307.5 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 total credit facilities were increased from $485.0 million to $515.0 million in June 2009. The facilities are subject to semi-annual review and are secured by a floating charge over all Baytex assets.

The credit facilities of Baytex 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 $515 million credit facility, 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 USD 179.7 million) and 10.5% notes due February 15, 2011 (principal amount USD 0.2 million).

Pursuant to various agreements with Baytex creditors, we are restricted from making distributions to unitholders if 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 or the Series A senior unsecured debentures.

The Trust believes that cash flow generated from operations, together with the existing bank 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 a reduction in commodity prices.

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 cash flows in an ongoing manner. A significant portion of these obligations will be funded through cash flow generated from operations. These obligations as of September 30, 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	155,009	155,009	–	–	–
Distributions payable to unitholders	12,933	12,933	–	–	–
Bank loan(1)	272,918	272,918	–	–	–
Long-term debt	150,000	–	–	–	150,000
Convertible debentures(2)	8,911	–	8,911	–	–
Deferred obligations	37	25	12	–	–
Operating leases	40,559	3,120	7,570	7,368	22,501
Processing and transportation agreements	17,509	8,446	8,910	153	–
Total	657,876	452,451	25,403	7,521	172,501

(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 is authorized to issue an unlimited number of trust units. As at November 6, 2009, the Trust had 108,232,664 trust units issued and outstanding.

At November 6, 2009, the Trust had $8.6 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.

Capital Expenditures

Capital expenditures for the three months and nine months ended September 30, 2009 and 2008 are summarized as follows:

	Three Months Ended		Nine Months Ended	
($ thousands)	**September 30, 2009**	September 30, 2008	**September 30, 2009**	September 30, 2008
Land	**2,902**	450	**9,715**	4,636
Seismic	**114**	531	**1,958**	1,439
Drilling and completion	**23,537**	34,827	**81,329**	104,503
Equipment	**7,893**	11,712	**17,652**	28,968
Other	**2,031**	1,064	**3,765**	2,568
Total exploration and development	**36,477**	48,584	**114,419**	142,114
Corporate acquisition	**–**	–	**–**	178,351
Property acquisitions	**93,670**	78,701	**96,012**	78,702
Property dispositions	**(8)**	(66)	**(18)**	(128)
Total capital expenditures	**130,139**	127,219	**210,413**	399,039

Subsequent to September 30, 2009, a subsidiary of the Company has reached an agreement with one of its joint venture partners to pre-pay the remaining deferred acquisition payments on the North Dakota light oil resource play by December 15, 2009. The original participation agreement with the joint venture partner called for deferred acquisition payments totaling approximately US$36 million to be made prior to the spud of each of the remaining 24 wells, occurring more or less ratably until approximately January 2011. The early payment of US$33.2 million will complete the remaining deferred acquisition payments and earn the subsidiary the right to operate a portion of the joint project area effective at the beginning of 2010.

Financial Instruments and Risk Management

The Trust 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 the Trust through a series of derivative contracts intended to manage the volatility of its operating cash flow. Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust 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 Trust incurring a loss. The Trust manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis.

Details of the risk management contracts in place as at September 30, 2009, and the accounting for the Trust's financial instruments are disclosed in note 14 to the consolidated financial statements.

Selected Quarterly Financial Information

	2009			2008				2007
($ thousands, except per unit amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**208,229**	192,667	150,943	199,890	363,044	332,336	264,448	233,856
Net income (loss)	**40,657**	27,451	(8,490)	52,401	137,228	34,417	35,848	41,353
Net income (loss) per unit – basic	**0.38**	0.26	(0.09)	0.54	1.44	0.39	0.42	0.49
Net income (loss) per unit – diluted	**0.37**	0.26	(0.09)	0.53	1.39	0.38	0.41	0.46

Changes in Accounting Policies

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.

Effective July 1, 2009, the Trust prospectively adopted the CICA amendments to section 3855, "Financial Instruments – Recognition and Measurement." Amendments to this section have prohibited the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. The adoption of the amendments to this standard did not have an impact on the Trust's financial statements.

Future Accounting Changes

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate International Financial Reporting Standards ("IFRS") into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust is currently reviewing the standards to determine the potential impact on its consolidated financial statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from senior management. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

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 accounting of future business combinations.

In January 2009, the CICA issued Section 1601 which establishes standards for the preparation of consolidated financial statements and Section 1602 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 accounting of future business combinations.

In June 2009, the CICA amended Section 3862 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 plans to adopt this standard prospectively effective December 31, 2009. The adoption of this standard will not have a material impact on the consolidated financial statements of the Trust.

In July 2009, 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 plans to adopt this standard prospectively effective December 31, 2009. The adoption of the amendments of this standard will not have a material impact on the consolidated financial statements of the Trust.

Disclosure Controls and Procedures

Anthony Marino, the President and Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer, of Baytex Energy Ltd. (together the "Disclosure Officers") are responsible for establishing and maintaining disclosure controls and procedures for Baytex. They have designed such disclosure controls and procedures, or caused them to be designed under their supervision, to provide reasonable assurance that all material or potentially material information about the activities of Baytex is made known to them by others within Baytex.

It should be noted that while the Disclosure Officers believe that Baytex's disclosure controls and procedures provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

Under the supervision and with participation of the Disclosure Officers, we conducted an evaluation of the design and effectiveness of our internal control over financial reporting as of December 31, 2008 based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that as of December 31, 2008, Baytex did maintain effective internal control over financial reporting.

There were no changes in our internal control over financial reporting during the nine months ended September 30, 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Advisory Regarding 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", "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: funding sources for our cash distributions and capital program; the sufficiency of our capital resources to meet our ongoing short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the timing of funding our financial obligations; and the impact of the adoption of new accounting standards on our financial results.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil 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: general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes in income tax laws, royalty rates and incentive programs relating to the oil and gas industry and income trusts; changes in environmental and other regulations; risks associated with oil and gas operations; 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, 2008, 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.

CONSOLIDATED BALANCE SHEETS

(thousands of Canadian dollars) (unaudited)	September 30, 2009	December 31, 2008
ASSETS		
Current assets		
Cash	$ 1,843	$ –
Accounts receivable	129,269	87,551
Crude oil inventory	2,294	332
Future tax asset	567	–
Financial instruments (note 14)	35,253	85,678
	169,226	173,561
Future tax asset	1,298	–
Financial instruments (note 14)	6,779	–
Petroleum and natural gas properties	1,647,205	1,601,017
Goodwill	37,755	37,755
	$ 1,862,263	$ 1,812,333
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 155,009	$ 164,279
Distributions payable to unitholders	12,933	17,583
Bank loan	272,918	208,482
Future tax liability	10,417	25,358
Financial instruments (note 14)	1,920	–
	453,197	415,702
Long-term debt (note 3)	150,000	217,273
Convertible debentures (note 4)	8,799	10,195
Asset retirement obligations (note 5)	55,017	49,351
Deferred obligations	37	74
Future tax liability	182,332	192,411
Financial instruments (note 14)	4,392	–
	853,774	885,006
UNITHOLDERS' EQUITY		
Unitholders' capital (note 6)	1,268,988	1,129,909
Conversion feature of convertible debentures (note 4)	427	498
Contributed surplus (note 9)	22,870	21,234
Accumulated other comprehensive loss (note 7)	(741)	–
Deficit	(283,055)	(224,314)
	1,008,489	927,327
	$ 1,862,263	$ 1,812,333

Commitments and contingencies (note 15)
Subsequent event (note 17)
See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands of Canadian dollars, except per unit amounts) (unaudited)	Three Months Ended September 30 2009	Three Months Ended September 30 2008	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008
Revenue				
Petroleum and natural gas	$ 208,229	$ 363,044	$ 551,839	$ 959,828
Royalties	(39,992)	(72,833)	(90,348)	(175,832)
Gain (loss) on financial instruments (note 14)	23,580	66,654	20,308	(24,525)
	191,817	356,865	481,799	759,471
Expenses				
Operating	40,212	46,399	118,549	125,116
Transportation and blending	36,479	57,077	113,354	172,988
General and administrative	6,674	7,071	22,079	21,968
Unit-based compensation (note 9)	1,669	2,038	4,826	6,249
Interest (note 12)	10,385	8,192	26,226	24,652
Financing charges	3,361	35	5,174	450
Foreign exchange (gain) loss (note 13)	(11,112)	7,064	(19,433)	12,937
Depletion, depreciation and accretion	58,637	61,250	170,220	162,649
	146,305	189,126	440,995	527,009
Income before taxes and non-controlling interest	45,512	167,739	40,804	232,462
Tax expense (recovery) (note 11)				
Current expense	2,925	3,176	7,431	8,445
Future expense (recovery)	1,930	25,962	(26,245)	13,166
	4,855	29,138	(18,814)	21,611
Income before non-controlling interest	40,657	138,601	59,618	210,851
Non-controlling interest (note 8)	–	(1,373)	–	(3,358)
Net income	$ 40,657	$ 137,228	$ 59,618	$ 207,493
Other comprehensive loss				
Foreign currency translation adjustment (note 7)	(9,720)	–	(741)	–
Comprehensive income	$ 30,937	$ 137,228	$ 58,877	$ 207,493
Net income per trust unit (note 10)				
Basic	$ 0.38	$ 1.44	$ 0.57	$ 2.31
Diluted	$ 0.37	$ 1.39	$ 0.57	$ 2.23
Weighted average trust units (note 10)				
Basic	107,368	95,597	103,688	89,796
Diluted	110,562	99,976	105,551	94,943

CONSOLIDATED STATEMENTS OF DEFICIT

(thousands of Canadian dollars) (unaudited)	Three Months Ended September 30 2009	Three Months Ended September 30 2008	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008
Deficit, beginning of period	$ (285,014)	$ (275,590)	$ (224,314)	$ (239,727)
Net income	40,657	137,228	59,618	207,493
Distributions to unitholders	(38,698)	(72,132)	(118,359)	(178,260)
Deficit, end of period	$ (283,055)	$ (210,494)	$ (283,055)	$ (210,494)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands of Canadian dollars) (unaudited)	2009	2008	2009	2008
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income	$ 40,657	$ 137,228	$ 59,618	$ 207,493
Items not affecting cash:				
Unit-based compensation (note 9)	1,669	2,038	4,826	6,249
Unrealized foreign exchange loss	10,932	7,306	1,636	12,680
Depletion, depreciation and accretion	58,637	61,250	170,220	162,649
Accretion on debentures and notes (notes 3 & 4)	1,980	439	2,892	1,162
Unrealized (gain) loss on financial instruments (note 14)	(3,311)	(89,010)	45,580	(33,406)
Future tax expense (recovery)	1,930	25,962	(26,245)	13,166
Non-controlling interest (note 8)	–	1,373	–	3,358
Realized foreign exchange gain on redemption of long-term debt (note 3)	(23,685)	–	(23,685)	–
	88,809	146,586	234,842	373,351
Change in non-cash working capital	(16,215)	4,591	(41,882)	229
Asset retirement expenditures (note 5)	(228)	(351)	(990)	(718)
Decrease in deferred obligations	(11)	(11)	(34)	(32)
	72,355	150,815	191,936	372,830
Financing activities				
Payments of distributions	(32,201)	(54,817)	(103,823)	(133,501)
Increase (decrease) in bank loan	121,394	20,445	67,178	(41,303)
Redemption of long-term debt (note 3)	(196,411)	–	(196,411)	–
Proceeds from issuance of long-term debt (note 3)	150,000	–	150,000	–
Issue of trust units (note 6)	2,953	1,629	120,352	10,275
Issuance costs (note 6)	(6)	–	(6,101)	(150)
	45,729	(32,743)	31,195	(164,679)
Investing activities				
Petroleum and natural gas property expenditures	(36,477)	(48,584)	(114,419)	(142,114)
Acquisition of petroleum and natural gas properties, net	(93,662)	(78,635)	(95,994)	(80,392)
Change in non-cash working capital	11,937	9,147	(11,000)	14,355
	(118,202)	(118,072)	(221,413)	(208,151)
Impact of foreign exchange on cash balances	(3)	–	125	–
Change in cash	(121)	–	1,843	–
Cash, beginning of period	1,964	–	–	–
Cash, end of period	$ 1,843	$ –	$ 1,843	$ –

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Pursuant to the Plan of Arrangement, the Company became a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Trust as at December 31, 2008, except as noted below. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust's annual consolidated financial statements and notes thereto for the year ended December 31, 2008.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009, the Trust adopted the following new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 3064 "Goodwill and Intangible Assets" and EIC-173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". These standards were adopted retrospectively without restatement of prior periods.

Goodwill and Intangible Assets

Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to their initial recognition. The adoption of this new standard did not have a material impact on the consolidated financial statements of the Trust.

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.

Financial Instruments – Recognition and Measurement

Effective July 1, 2009, the Trust prospectively adopted the CICA amendments to section 3855, "Financial Instruments – Recognition and Measurement." Amendments to this section have prohibited the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. The adoption of the amendments to this standard did not have an impact on the Trust's consolidated financial statements.

Future Accounting Changes

Business Combinations

In January 2009, the CICA issued Section 1582 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 accounting for future business combinations.

Consolidated Financial Statements

In January 2009, the CICA issued Section 1601 which establishes standards for the preparation of consolidated financial statements and Section 1602 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 these standards prospectively effective January 1, 2011. The adoption of these standards may have an impact on the Trust's accounting for future business combinations.

Financial Instruments – Disclosures

In June 2009, the CICA amended Section 3862 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 plans to adopt this standard prospectively effective December 31, 2009. The adoption of this standard will not have a material impact on the consolidated financial statements of the Trust.

Financial Instruments – Recognition and Measurement

In July 2009, 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 plans to adopt this standard prospectively effective December 31, 2009. The adoption of the amendments of this standard will not have a material impact on the consolidated financial statements of the Trust.

International Financial Reporting Standards ("IFRS")

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate IFRS into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences to determine the potential impact on its consolidated financial statements.

3. LONG-TERM DEBT

	September 30, 2009	December 31, 2008
9.15% senior unsecured debentures	**$ 150,000**	$ –
10.5% senior subordinated notes (USD 247)	**–**	303
9.625% senior subordinated notes (USD 179,699)	**–**	220,059
	150,000	220,362
Discontinued fair value hedge	**–**	(3,089)
	$ 150,000	$ 217,273

On August 26, 2009, the Trust closed its offering of $150.0 million Series A senior unsecured debentures bearing interest at 9.15% payable semi-annually with principal repayable on August 26, 2016. These debentures are unsecured and are subordinate to the Company's bank credit facilities. After August 26 of each of the following years, these debentures are redeemable at the Trust's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2012 at 104.575%, 2013 at 103.05%, 2014 at 101.525%, and 2015 at 100%.

On September 25, 2009, the Company redeemed all of the 9.625% senior subordinated notes due July 15, 2010 (principal amount USD 179.7 million) and 10.5% senior subordinated notes due February 15, 2011 (principal amount USD 0.2 million) for an aggregate redemption price of $196.4 million. These notes were unsecured and were subordinate to the Company's bank credit facilities. These notes were carried at amortized cost, net of a discontinued fair value hedge of $6.0 million which was recorded on adoption of CICA Handbook Section 3865 "Hedges". The notes would accrete up to the principal balance at maturity using the effective interest method.

The Company recorded accretion expense of $2.0 million for the three months ended September 30, 2009 ($0.4 million for the three months ended September 30, 2008) and $2.8 million for the nine months ended September 30, 2009 ($1.1 million for the nine months ended September 30, 2008). The effective interest rate was 10.6%. The discontinued fair value hedge has been recognized in accretion expense upon redemption of the senior subordinated notes.

4. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

	Number of Convertible Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2007	16,620	$ 16,150	$ 796
Conversion	(6,222)	(6,052)	(298)
Accretion	–	97	–
Balance, December 31, 2008	10,398	$ 10,195	$ 498
Conversion	(1,487)	(1,464)	(71)
Accretion	–	68	–
Balance, September 30, 2009	**8,911**	**$ 8,799**	**$ 427**

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010, at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

5. ASSET RETIREMENT OBLIGATIONS

	September 30, 2009	December 31, 2008
Balance, beginning of period	$ 49,351	$ 45,113
Liabilities incurred	1,083	871
Liabilities settled	(990)	(1,443)
Acquisition of liabilities	3,268	1,536
Disposition of liabilities	(133)	(904)
Accretion	3,079	3,802
Change in estimate(1)	(630)	376
Foreign exchange	(11)	–
Balance, end of period	$ 55,017	$ 49,351

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

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at September 30, 2009 is $295.6 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0% and an estimated annual inflation rate of 2.0%.

6. UNITHOLDERS' CAPITAL

The Trust is authorized to issue an unlimited number of trust units.

	Number of Units	Amount
Balance, December 31, 2007	84,540	$ 821,624
Issued on conversion of debentures	422	6,350
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of unit rights	1,386	10,653
Transfer from contributed surplus on exercise of unit rights	–	5,105
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	2,167	47,386
Balance, December 31, 2008	97,685	$ 1,129,909
Issued for cash	7,935	115,058
Issuance costs, net of tax	–	(5,185)
Issued on conversion of debentures	101	1,536
Issued on exercise of unit rights	862	5,294
Transfer from contributed surplus on exercise of unit rights	–	3,190
Issued pursuant to distribution reinvestment plan	1,194	19,186
Balance, September 30, 2009	**107,777**	**$ 1,268,988**

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

	September 30, 2009	December 31, 2008
Balance, beginning of period	$ –	$ –
Cumulative foreign currency translation adjustment	(741)	–
Balance, end of period	$ (741)	$ –

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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 (USD/CAD 0.9327), while revenues and expenses are translated using the average exchange rate for the three month and nine month periods ended September 30, 2009 (USD/CAD 0.9113 and 0.8547, respectively). Translation gains and losses are deferred and included in other comprehensive income in unitholders' equity 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.

8. NON-CONTROLLING INTEREST

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2007	1,566	$ 21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	–	3,358
Balance, December 31, 2008	–	$ –
Balance, September 30, 2009	**–**	**$ –**

On May 30, 2008, the Trust announced that the Company had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, 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. As at September 30, 2009 and December 31, 2008, there were no exchangeable shares outstanding.

9. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of unit rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of unit rights available to grant under the Plan. The unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the unit rights to be reduced to account for future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $1.7 million for the three months ended September 30, 2009 (three months ended September 30, 2008 – $2.0 million) and $4.8 million for the nine months ended September 30, 2009 (nine months ended September 30, 2008 – $6.2 million) related to the unit rights granted under the Plan.

The Trust uses the binomial-lattice model to calculate the estimated weighted average fair value of $3.64 per unit for unit rights issued during the nine months ended September 30, 2009 ($5.10 per unit for the nine months ended September 30, 2008). The following assumptions were used to arrive at the estimate of fair values:

	Three Months and Nine Months Ended September 30	
	2009	2008
Expected annual exercise price reduction	**$1.50**	$2.71
Expected volatility	**39% – 43%**	28%
Risk-free interest rate	**1.78% – 2.60%**	2.98% – 4.17%
Expected life of unit rights (years)(1)	**Various**	Various

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Plan.

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

	Number of unit rights	Weighted average exercise price(1)
Balance, December 31, 2007	7,662	$ 14.67
Granted	2,838	$ 19.27
Exercised	(1,386)	$ 7.69
Cancelled	(665)	$ 21.79
Balance, December 31, 2008	8,449	$ 14.58
Granted	532	$ 17.01
Exercised	(862)	$ 6.14
Cancelled	(91)	$ 16.59
Balance, September 30, 2009	**8,028**	**$ 14.50**

(1) Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at September 30, 2009:

Range of Exercise Prices			Number Outstanding at September 30, 2009	Weighted Average Remaining Term *(years)*	Weighted Average Exercise Price	Number Exercisable at September 30, 2009	Weighted Average Exercise Price
$2.76	to	$7.50	**1,119**	1.0	$ 6.19	**1,119**	$ 6.19
$7.51	to	$12.00	**245**	1.4	$ 9.36	**230**	$ 9.21
$12.01	to	$16.50	**6,049**	3.2	$ 15.75	**1,725**	$ 15.56
$16.51	to	$21.00	**373**	2.7	$ 17.44	**204**	$ 17.10
$21.01	to	$25.31	**242**	4.6	$ 22.47	**15**	$ 24.79
$2.76	to	$25.31	**8,028**	2.9	$ 14.50	**3,293**	$ 12.07

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2007	$ 18,527
Compensation expense	7,812
Transfer from contributed surplus on exercise of unit rights(1)	(5,105)
Balance, December 31, 2008	$ 21,234
Compensation expense	4,826
Transfer from contributed surplus on exercise of unit rights(1)	(3,190)
Balance, September 30, 2009	**$ 22,870**

(1) Upon exercise of unit rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

10. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding unit rights on net income per unit. The weighted average exchangeable shares outstanding during the period, converted at the period-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	Three Months Ended September 30					
	2009			2008		
	Net income	Trust units	Net income per unit	Net income	Trust units	Net income per unit
Net income per basic unit	$ 40,657	107,368	$ 0.38	$ 137,228	95,597	$ 1.44
Dilutive effect of unit rights	–	2,549		–	3,117	
Conversion of convertible debentures	101	645		142	755	
Exchange of exchangeable shares	–	–		1,373	507	
Net income per diluted unit	$ 40,758	110,562	$ 0.37	$ 138,743	99,976	$ 1.39

	Nine Months Ended September 30					
	2009			2008		
	Net income	Trust units	Net income per unit	Net income	Trust units	Net income per unit
Net income per basic unit	$ 59,618	103,688	$ 0.57	$ 207,493	89,796	$ 2.31
Dilutive effect of unit rights	–	1,180		–	3,044	
Conversion of convertible debentures	335	683		521	940	
Exchange of exchangeable shares	–	–		3,358	1,163	
Net income per diluted unit	$ 59,953	105,551	$ 0.57	$ 211,372	94,943	$ 2.23

For the nine months ended September 30, 2009, 4.5 million unit rights (nine months ended September 30, 2008 – 0.3 million) were excluded in calculating the weighted average number of diluted trust units outstanding as they were anti-dilutive.

11. TAX EXPENSE (RECOVERY)

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

	Nine Months Ended September 30	
	2009	2008
Income before taxes and non-controlling interest	$ 40,804	$ 232,462
Expected taxes at the statutory rate of 29.55% (2008 – 30.22%)	12,058	70,250
Increase (decrease) in taxes resulting from:		
Net earnings of the Trust	(35,367)	(57,008)
Non-taxable portion of foreign exchange (gain) loss	(3,538)	1,881
Effect of change in tax rate	(136)	(5,930)
Effect of change in opening tax pool balances	3,737	1,755
Effect of change in valuation allowance	(4,537)	–
Unit-based compensation	1,426	1,888
Other	112	330
Future tax (recovery) expense	(26,245)	13,166
Current tax expense	7,431	8,445
Tax (recovery) expense	$ (18,814)	$ 21,611

12. INTEREST EXPENSE

The Trust incurred interest expense on its outstanding debts as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Bank loan and other	$ 2,399	$ 3,060	$ 6,547	$ 9,579
Long-term debt	7,810	4,927	19,119	14,321
Convertible debentures	176	205	560	752
Interest expense	$ 10,385	$ 8,192	$ 26,226	$ 24,652

13. SUPPLEMENTAL INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Interest paid	$ 19,505	$ 11,642	$ 35,613	$ 28,122
Income taxes paid	$ 689	$ 1,781	$ 6,566	$ 4,150

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Unrealized foreign exchange loss	$ 10,932	$ 7,306	$ 1,636	$ 12,680
Realized foreign exchange (gain) loss[1]	(22,044)	(242)	(21,069)	257
Foreign exchange (gain) loss	$ (11,112)	$ 7,064	$ (19,433)	$ 12,937

(1) The settlement on September 25, 2009 of the US$ senior subordinated notes resulted in a realized gain of $51.0 million. Only $23.7 million of this gain is recognized in the current period as $27.3 million has already been recorded in prior periods as unrealized foreign exchange gain through the translation process at each period end.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial assets and liabilities are comprised of cash, accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, financial instruments, long-term debt, convertible debentures and deferred obligations.

Categories of Financial Instruments

Under Canadian generally accepted accounting principles, financial instruments are classified into one of the following five categories: held-for-trading, held to maturity, loans and receivables, available-for-sale and other financial liabilities. The carrying value and fair value of the Trust's financial instruments on the consolidated balance sheet are classified into the following categories:

	September 30, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Held for trading				
Cash	$ 1,843	$ 1,843	$ –	$ –
Derivatives designated as held for trading	42,032	42,032	85,678	85,678
Total held for trading	$ 43,875	$ 43,875	$ 85,678	$ 85,678
Loans and receivables				
Accounts receivable	$ 129,269	$ 129,269	$ 87,551	$ 87,551
Total loans and receivables	$ 129,269	$ 129,269	$ 87,551	$ 87,551
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	$ (6,312)	$ (6,312)	$ –	$ –
Total held for trading	$ (6,312)	$ (6,312)	$ –	$ –
Other financial liabilities				
Accounts payable and accrued liabilities	$ (155,009)	$ (155,009)	$ (164,279)	$ (164,279)
Distributions payable to unitholders	(12,933)	(12,933)	(17,583)	(17,583)
Bank loan	(272,918)	(272,918)	(208,482)	(208,482)
Long-term debt	(150,000)	(158,250)	(217,273)	(200,557)
Convertible debentures	(8,799)	(14,302)	(10,195)	(9,837)
Total other financial liabilities	$ (599,659)	$ (613,412)	$ (617,812)	$ (600,738)

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than long-term debt and convertible debentures, approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its book value as it is at a market rate of interest. The fair value of the long-term debt is based on the lower of trading value and the present value of future cash flows associated with the debentures. The fair value of the convertible debentures has been calculated based on the lower of trading value and the present value of future cash flows plus the conversion option associated with the convertible debentures. The Trust expenses all financial instrument transaction costs immediately.

Financial Risk

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

Market Risk

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

Foreign currency risk

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

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

At September 30, 2009, the Trust had in place the following currency swaps:

	Period	Amount per month	Swap Price(1)
Swap	January 1, 2009 to December 31, 2009	USD 10.0 million	0.8074
Swap	May 1, 2009 to December 31, 2009	USD 3.0 million	0.8602
Swap	July 1, 2009 to December 31, 2009	USD 2.0 million	0.8582
Swap	January 1, 2010 to December 31, 2010	USD 8.0 million	0.8197
Swap	January 1, 2010 to March 31, 2011	USD 5.0 million	0.8696

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

The following table demonstrates the effect of exchange rate movement on net income before taxes and non-controlling interest due to changes in the fair value of its currency swap as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at September 30, 2009.

	$0.01 Increase/Decrease in CAD/USD Exchange Rate
Gain/loss on currency swap	$ 2,097
Gain/loss on other monetary assets/liabilities	1,489
Impact on income before taxes and non-controlling interest	$ 3,586

The carrying amounts of the Trust's foreign currency denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	September 30, 2009	December 31, 2008	**September 30, 2009**	December 31, 2008
U.S. dollar denominated	**USD 66,866**	USD 84,070	**USD 188,886**	USD 191,571

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Subsequent to September 30, 2009, the Trust added the following currency swaps:

	Period	Amount per month	Swap Price[(1)]
Swap	October 1, 2009 to December 31, 2010	USD 1.0 million	0.9200
Swap	January 1, 2010 to December 31, 2011	USD 3.0 million	0.9272
Swap	January 1, 2010 to December 31, 2010	USD 2.0 million	0.9390

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

Interest rate risk

The Trust's interest rate risk arises from the Company's floating rate bank credit facilities. As at September 30, 2009, $272.9 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 100 basis points in interest rates would impact cash flow for the nine months ended September 30, 2009 by approximately $1.6 million. The Trust uses a combination of short-term and long-term debt to finance operations. Short-term debt is typically at floating rates of interest and debentures bear fixed rates of interest.

At September 30, 2009, the Trust had the following interest swap financial derivative contracts:

Type	Period	Amount per month	Fixed interest rate	Floating rate index
Swap – pay floating, receive fixed	September 23, 2009 to August 26, 2011	CAD 150.0 million	9.15%	3 month BA plus 7.875%
Swap – pay fixed, receive floating	September 27, 2011 to September 27, 2014	USD 90.0 million	4.06%	3 month LIBOR
Swap – pay fixed, receive floating	September 25, 2012 to September 25, 2014	USD 90.0 million	4.39%	3 month LIBOR

When assessing the potential impact of forward interest rate changes, an increase or decrease of 100 basis points would result in an increase or decrease, respectively, to the unrealized gain in the third quarter of 2009 of $2.1 million relating to financial derivative instruments outstanding as at September 30, 2009.

Commodity Price Risk

The Trust monitors and, when appropriate, utilizes financial derivative agreements or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of the Company. Under the Trust's risk management policy, financial instruments are not to be used for speculative purposes.

When assessing the potential impact of commodity price changes, a 10% increase in commodity prices would result in a reduction to the unrealized gain in the third quarter of 2009 of $10.9 million relating to the financial derivative instruments outstanding as at September 30, 2009, while a 10% decrease would result in an increase to the unrealized gain of $10.7 million.

Financial Derivative Agreements

At September 30, 2009, the Trust had the following commodity derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – 136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – 172.70	WTI
Fixed – Buy	Calendar 2010	575 bbl/d	USD 64.00	WTI
Fixed – Sell	July 1, 2009 to December 31, 2009	1,155 bbl/d	USD 61.60	WTI
Price collar	July 1, 2009 to December 31, 2009	2,000 bbl/d	USD 60.00 – 77.40	WTI
Fixed – Sell	Calendar 2010	1,200 bbl/d	USD 77.78	WTI

Gas	Period	Volume	Price/Unit	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – 6.30	AECO
Price collar	Calendar 2010	1,000 GJ/d	CAD 5.50 – 7.00	AECO
Fixed – Sell	Calendar 2010	3,000 GJ/d	CAD 6.19	AECO
Fixed – Sell	January to February 2010	10,000 MMBtu/d	USD 5.63 – 5.66	NYMEX
Sold call	January to February 2011	15,000 MMBtu/d	USD 7.00	NYMEX
Fixed – Sell	December 2009	5,000 GJ/d	USD 4.47	AECO
Fixed – Sell	November 2009	2,500 MMBtu/d	USD 4.52	NYMEX
Fixed – Sell	December 2009	2,500 MMBtu/d	USD 5.31	NYMEX
Fixed – Buy	December 2010	2,500 MMBtu/d	USD 6.86	NYMEX
Fixed – Buy	December 2010	2,500 MMBtu/d	USD 6.86	NYMEX
Fixed – Sell	Calendar 2010	2,000 GJ/d	CAD 5.05	AECO
Fixed – Sell	Calendar 2010	2,000 GJ/d	CAD 5.05	AECO
Fixed – Sell	December 2009	2,500 MMBtu/d	USD 4.41	NYMEX
Fixed – Sell	March 2010	2,500 MMBtu/d	USD 4.78	NYMEX
Sold call	January to March 2011	5,000 MMBtu/d	USD 6.60	NYMEX
Fixed – Buy	April 2011	2,500 MMBtu/d	USD 5.97	NYMEX
Fixed – Buy	April 2011	2,500 MMBtu/d	USD 5.97	NYMEX

The financial derivative contracts are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income and comprehensive income:

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Realized gain (loss) on financial instruments	$ 20,269	$ (22,356)	$ 65,888	$ (57,931)
Unrealized gain (loss) on financial instruments	3,311	89,010	(45,580)	33,406
Gain (loss) on financial instruments	$ 23,580	$ 66,654	$ 20,308	$ (24,525)

Subsequent to September 30, 2009, the Trust added the following commodity derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Price collar	Calendar 2010	2,000 bbl/d	USD 70.00 – 95.65	WTI
Price collar	Calendar 2010	1,000 bbl/d	USD 75.00 – 87.60	WTI
Fixed – Sell	Calendar 2010	1,000 bbl/d	USD 83.10	WTI

Gas	Period	Volume	Price/Unit	Index
Fixed – Buy	November 2009	2,500 MMBtu/d	USD 4.38	NYMEX
Fixed – Sell	December 2010	2,500 MMBtu/d	USD 6.72	NYMEX

Physical Delivery Contracts

At September 30, 2009, the Trust had the following crude oil supply and condensate purchase contracts:

Heavy Oil	Period	Volume	Weighted Average Price/Unit
WCS Blend	Calendar 2009	10,340 bbl/d	WTI × 67.0%
WCS Blend	Calendar 2010	2,500 bbl/d	USD 51.04
Condensate	Calendar 2010	575 bbl/d	WTI plus USD 2.25 – 2.60
WCS Blend	July to December 2009	1,500 bbl/d	WTI less USD 10.55
Condensate	July to December 2009	207 bbl/d	WTI less USD 2.50
WCS Blend	Calendar 2010	1,500 bbl/d	WTI less USD 14.50
WCS Blend	January to June 2010	1,500 bbl/d	WTI less USD 10.75
WCS Blend	January to June 2010	1,500 bbl/d	WTI × 84.5%

Subsequent to September 30, 2009, the Trust added the following physical crude oil supply contracts:

Heavy Oil	Period	Volume	Weighted Average Price/Unit
WCS Blend	July to December 2010	1,000 bbl/d	WTI less USD 14.08
WCS Blend	July to December 2010	1,000 bbl/d	WTI × 81.06%
WCS Blend	January to June 2010	1,000 bbl/d	WTI less USD 12.45
WCS Blend	January to June 2010	1,000 bbl/d	WTI × 83.12%
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less 13.74
WCS Blend	Calendar 2010	1,000 bbl/d	WTI × 83.27%
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less USD 13.50

At September 30, 2009, the Trust had the following natural gas physical sales contracts:

Gas	Period	Volume	Price/Unit
Price collar	Calendar 2009	5,000 GJ/d	AECO CAD 7.00 – 7.95
Price collar	Calendar 2010	5,000 GJ/d	AECO CAD 5.00 – 6.28
Price swap	December 2009	5,000 GJ/d	AECO CAD 4.53
Price swap	December 2009	2,500 GJ/d	AECO CAD 4.15
Price swap	November 2009	5,000 GJ/d	AECO CAD 4.23
Price swap	November 2009	5,000 GJ/d	AECO CAD 4.22

At September 30, 2009, the Trust had the following power contracts:

Power	Period	Volume	Price/Unit
Fixed – Buy	October 1, 2008 to December 31, 2009	0.6 MW/hr	CAD 78.61
Fixed – Buy	October 1, 2008 to December 31, 2009	0.6 MW/hr	CAD 79.92
Fixed – Buy	March 1, 2009 to June 30, 2010	0.6 MW/hr	CAD 76.89

Liquidity Risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. As at September 30, 2009, the Trust had available unused bank credit facilities in the amount of $206 million.

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

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Accounts payable and accrued liabilities	$ 155,009	$ 155,009	$ –	$ –	$ –
Distributions payable to unitholders	12,933	12,933	–	–	–
Bank loan(1)	272,918	272,918	–	–	–
Long-term debt	150,000	–	–	–	150,000
Convertible debentures(2)	8,911	–	8,911	–	–
	$ 599,771	$ 440,860	$ 8,911	$ –	$ 150,000

(1) The bank loan is a 364-day revolving loan with the ability to extend the term.
(2) Principal amount of instruments.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only creditworthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income.

As at September 30, 2009, accounts receivable include a $7.4 million balance over 90 days (December 31, 2008 – $9.9 million) and a balance of $2.4 million (December 31, 2008 – $2.4 million) has been set up as allowance for doubtful accounts.

15. COMMITMENTS AND CONTINGENCIES

At September 30, 2009, the Trust had operating leases and processing and transportation obligations as summarized below:

	Total	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Beyond 5 years
Operating leases	$ 40,559	$ 3,120	$ 3,732	$ 3,838	$ 3,684	$ 3,684	$22,501
Processing and transportation agreements	17,509	8,446	7,188	1,722	141	12	–
Total	$ 58,068	$11,566	$10,920	$ 5,560	$ 3,825	$ 3,696	$22,501

Other

At September 30, 2009, there were outstanding letters of credit aggregating $1.8 million (December 31, 2008 – $2.3 million) issued as security for performance under certain contracts.

In connection with a purchase of properties in 2005, the Company became liable for contingent consideration whereby an additional amount would be payable by the Company if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase; therefore, such consideration is recognized only when the contingency is resolved. As at September 30, 2009, additional payments totaling $7.2 million have been paid under the agreement and recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement; therefore, no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

16. CAPITAL DISCLOSURES

The Trust's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP measure which is the sum of monetary working capital (being current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial instruments gains or losses)), the principal amount of long-term debt and the balance sheet value of the convertible debentures.

The Trust's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, the Trust may adjust the amount of its distributions, adjust its level of capital spending, issue new trust units, issue new debt or sell assets to reduce debt.

The Trust monitors capital based on current and projected ratios of total monetary debt to funds from operations and the current and projected level of its undrawn bank credit facilities. The Trust's objectives are to maintain a total monetary debt to funds from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to funds from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to funds from operations ratio and the level of undrawn bank credit facilities, the Trust continuously monitors its funds from operations and evaluates its distribution policy and capital spending plans.

The Trust's financial objectives and strategy as described above have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Trust believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

The Trust is subject to financial covenants relating to its bank credit facilities, senior subordinated debentures and convertible debentures. The Trust is in compliance with all financial covenants.

On June 22, 2007, new tax legislation modifying the taxation of specified investment flow-through entities, including income trusts such as the Trust, was enacted (the "New Tax Legislation"). The New Tax Legislation will apply a tax at the trust level on distributions of certain income from trusts. The New Tax Legislation permits "normal growth" for income trusts through the transitional period ending December 31, 2010. However, "undue expansion" could cause the transitional relief to be revisited, and the New Tax Legislation to be effective at a date earlier than January 1, 2011. On December 15, 2006, the Department of Finance released guidelines on normal growth for income trusts and other flow-through entities (the "Guidelines"). Under the Guidelines, trusts will be able to increase their equity capital each year during the transitional period by an amount equal to a safe harbour amount. The safe harbour amount is measured by reference to a trust's market capitalization as of the end of trading on October 31, 2006. The safe harbour amounts are 40% for the period from November 2006 to the end of 2007, and 20% per year for each of 2008, 2009 and 2010. The safe harbour amounts are cumulative allowing amounts not used in one year to be carried forward to a future year. Two trusts can merge without being impacted by the growth limitations. Limits are not impacted by non-convertible debt-financed growth, but rather focus solely on the issuance of equity to facilitate growth.

On December 4, 2008, the Minister of Finance announced changes to the Guidelines to allow an income trust to accelerate the utilization of the safe harbour amounts 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 an income trust, but it allows an income trust to use its safe harbour amount remaining as of December 4, 2008 in a single year, rather than staging a portion of the safe harbour amount over the 2009 and 2010 years. The Trust continues to review the impact of the future taxation of distributions on its business strategy but at this time has made no decision as to the ultimate legal form under which it will operate post 2010.

For the Trust, the safe harbour amounts were approximately $730 million for 2006/2007 and approximately $365 million for each of the subsequent three years with any unused amount carrying forward to the next year. The Trust did not issue equity in excess of its safe harbour amounts during 2006/2007 or 2008 or the first nine months of 2009. As at December 31, 2008, the Trust had an unused safe harbour amount of $596.6 million that was carried forward, resulting in a safe harbour amount of $1,326.6 million for 2009/2010. The Trust issued $139.1 million in equity during the nine months ended September 30, 2009, resulting in an unused available safe harbour amount of $1,187.5 million as at September 30, 2009.

17. SUBSEQUENT EVENT

A subsidiary of the Company has reached an agreement with one of its joint venture partners to pre-pay the remaining deferred acquisition payments on the North Dakota light oil resource play by December 15, 2009. The original participation agreement with the joint venture partner called for the deferred acquisition payments totaling approximately US$36 million to be made prior to the spud date of each of the remaining 24 wells, occurring more or less ratably until approximately January 2011. The early payment of US$33.2 million will complete the remaining deferred acquisition payments and earn the subsidiary the right to operate a portion of the joint project area effective at the beginning of 2010.

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ABBREVIATIONS

bbl	barrel	*Mcf*	thousand cubic feet
bbl/d	barrel per day	*Mcf/d*	thousand cubic feet per day
Bcf	billion cubic feet	*MMbbl*	million barrels
boe	barrels of oil equivalent	*MMboe*	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day	*MMcf*	million cubic feet
Mbbl	thousand barrels	*MMcf/d*	million cubic feet per day
Mboe	thousand barrels of oil equivalent	*NGL*	natural gas liquids

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CORPORATE INFORMATION

BOARD OF DIRECTORS

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Baytex Energy Ltd.

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

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

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

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

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

Gregory K. Melchin (1)
Independent Businessman

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

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

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BNP Paribas (Canada)
Canadian Imperial Bank of Commerce
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

OFFICERS

Raymond T. Chan
Executive Chairman

Anthony W. Marino
President & Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Heavy Oil

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

Brett J. McDonald
Vice President, Land

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

R. Shaun Paterson
Vice President, Marketing

Mark F. Smith
Vice President, Conventional Oil & Gas

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

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