Q3

BAYTEX

ENERGY TRUST

THIRD QUARTER REPORT

for the nine months ended September 30, 2005

HIGHLIGHTS

Baytex Energy Trust is pleased to announce its operating and financial results for the three months and nine months ended September 30, 2005.

Highlights of the third quarter in 2005 include:

- Increased average production to 34,780 boe/d, 6 percent higher than Q2/05.
- Achieved a third consecutive quarter of record cash flow of $67.5 million, 109 percent higher than the same period last year and 35 percent higher than the previous record set in Q2/05.
- Attained a payout ratio of 41 percent for the third quarter, after incurring hedging losses of $17.9 million. Excluding losses from hedges which are expiring at the end of 2005, the payout ratio would have been 32 percent.
- Completed an acquisition of heavy oil properties for $69 million which is highly accretive to production, reserves and cash flow, as well as opportunities for future development.

Financial	Three Months Ended			Nine Months Ended	
($ thousands, except per unit amounts)	**September 30, 2005**	June 30, 2005	September 30, 2004	**September 30, 2005**	September 30, 2004
Petroleum and natural gas sales	**154,930**	118,379	108,216	**384,584**	308,879
Cash flow from operations [1]	**67,501**	49,937	32,235	**161,978**	107,868
Per unit – basic	**1.00**	0.75	0.50	**2.42**	1.66
– diluted	**0.89**	0.71	0.49	**2.23**	1.65
Cash distributions	**27,495**	28,823	28,266	**85,639**	84,207
Per unit	**0.45**	0.45	0.45	**1.35**	1.35
Net income (loss)	**38,211**	18,804	(12,554)	**40,204**	(28,345)
Per unit – basic	**0.57**	0.28	(0.20)	**0.60**	(0.45)
– diluted	**0.51**	0.27	(0.20)	**0.57**	(0.45)
Exploration and development	**39,395**	31,586	20,686	**99,446**	65,460
Acquisitions – net of dispositions	**68,678**	847	110,316	**69,434**	110,760
Total capital expenditures	**108,073**	32,433	131,002	**168,880**	176,220
Long-term notes	**208,935**	220,542	227,434	**208,935**	227,434
Convertible debentures	**82,695**	95,255	-	**82,695**	-
Bank loan	**188,441**	109,267	113,843	**188,441**	113,843
Other working capital deficiency	**5,482**	16,916	20,237	**5,482**	20,237
Notional mark-to-market liabilities	**21,226**	30,761	50,098	**21,226**	50,098
Total net debt	**506,779**	472,741	411,612	**506,779**	411,612
Operating					
Daily production					
Light oil (bbls/d)	**4,063**	3,404	1,890	**3,782**	1,966
Heavy oil (bbls/d)	**20,061**	19,653	22,083	**20,326**	22,775
Total oil (bbls/d)	**24,124**	23,058	23,974	**24,108**	24,741
Natural gas (mmcf/d)	**63.9**	59.3	50.9	**60.9**	54.7
Oil equivalent (boe/d @ 6:1)	**34,780**	32,937	32,454	**34,261**	33,853

	Three Months Ended			Nine Months Ended	
	September 30, 2005	June 30, 2005	September 30, 2004	**September 30, 2005**	September 30, 2004
Average prices (before hedging)					
WTI oil (US$/bbl)	**63.19**	53.17	43.88	**55.40**	39.11
Edmonton par oil ($/bbl)	**76.51**	65.76	56.32	**67.90**	50.83
BTE light oil ($/bbl)	**59.24**	53.06	52.63	**53.15**	47.78
BTE heavy oil ($/bbl)	**45.39**	35.71	34.69	**37.23**	30.00
BTE total oil ($/bbl)	**47.74**	38.27	36.11	**39.73**	31.41
BTE natural gas ($/mcf)	**8.39**	7.08	6.16	**7.42**	6.41
BTE oil equivalent ($/boe)	**48.54**	39.53	36.34	**41.14**	33.31
Trust Unit Information					
Unit Price					
High	**$ 18.60**	$ 15.20	$ 13.13	**$ 18.60**	$ 13.13
Low	**$ 13.45**	$ 12.71	$ 11.65	**$ 12.42**	$ 9.78
Close	**$ 18.55**	$ 13.48	$ 12.88	**$ 18.55**	$ 12.88
Units Traded (thousands)	**22,134**	17,403	13,696	**65,947**	70,457
Units Outstanding (thousands) (2)	**70,524**	69,264	65,044	**70,524**	65,044
Foreign Ownership	**30%**	32%	33%	**30%**	33%

(1) Cash flow 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. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.

MESSAGE TO UNITHOLDERS

OPERATIONS REVIEW

On September 30, 2005, Baytex completed an acquisition of heavy oil properties in the Celtic area in Saskatchewan. Production from these properties is approximately 3,500 boe/d (3,350 bbl/d of heavy oil and 0.9 mmcf/d of natural gas) which will be included in Baytex's corporate production commencing in the fourth quarter of 2005. This transaction represents the first acquisition of producing properties in heavy oil since the Ardmore acquisition three years ago in October 2002, demonstrating the success of our commitment to focus on maintaining our production and asset base through internal development activities. The purchase price of the Celtic properties was earlier reported to be $73 million. A joint interest owner of certain associated operating facilities has since exercised a right of first refusal for Baytex's interest in such facilities, resulting in a $4 million reimbursement to Baytex and thereby reducing our net purchase price to $69 million. This auxiliary transaction has no impact on the production, reserves and land that are acquired by Baytex.

During the third quarter, capital expenditures for exploration and development activities totaled $39.4 million. Baytex participated in the drilling of 41 (37.1 net) wells, resulting in 19 (15.6 net) oil wells, 18 (18.0 net) gas wells and four (3.5 net) dry holes for an overall success rate of 90.2 percent (90.6 percent net). In addition, four farm-out wells were drilled at no costs to Baytex. Following record rainfall in the second quarter this year, wet field conditions were still prevalent in the third quarter, which caused delays in drilling and completion activities as well as the tie-in of new production. Nevertheless, production increased to average 34,780 boe/d in the third quarter, 6 percent higher than the production of the previous quarter. Natural gas and light oil production increased 11 percent quarter-over-quarter as new wells drilled in the Stoddart area were brought on-stream. Baytex completed a new 3D seismic survey in this area during the third quarter, which is expected to add to development inventory in this key natural gas project.

FINANCIAL REVIEW

Baytex achieved record cash flow for the third consecutive quarter thus far in 2005. Cash flow of $67.5 million ($1.00/unit basic) for the third quarter was 109 percent higher than the $32.2 million ($0.50/unit) for the same period last year and 35 percent higher than the previous record of $49.9 million ($0.75/unit) set in the second quarter this year. Baytex's strategy of minimizing dilution to unitholders is evident in these cash flow per unit comparisons, as total units outstanding increased by only 8 percent between Q3/05 and Q3/04 and by only 2 percent between Q3/05 and Q2/05. The majority of the new units issued in the third quarter were conversions from the 6.5% debentures, where $13.4 million of the original $100 million issue had been tendered for conversion as of September 30, 2005.

Cash distributions, net of DRIP participation, were 41 percent of cash flow in the quarter and 53 percent in the nine months ended September 30, 2005. These conservative payout ratios were achieved despite significant hedging losses incurred during these periods. Excluding hedging losses, the payout ratio would have been 32 percent for the third quarter and 44 percent for the first nine months in 2005. The underlying below-market hedging contracts will expire at the end of 2005.

For calendar 2006, Baytex has entered into WTI derivative contracts aggregating 8,000 bbl/d with a floor price of US$55.00 and an average cap price of US$84.39 (ranging between US$80.85 and US$87.35). These contracts will provide significant downside protection to 2006 cash flow while allowing for participation in the benefits of continued high oil prices. Baytex has also entered into several physical sales contracts for natural gas. For the upcoming winter season (November 2005 to March 2006), Baytex has sold 14.2 mmcf/d at an average fixed price of C$10.90 and another 4.7 mmcf/d at a collar between C$9.50 and C$14.14. For the summer season (April to October 2006), Baytex has sold 6.6 mmcf/d at an average fixed price of C$9.05 and another 6.6 mmcf/d at a collar between C$8.00 and C$11.09.

OUTLOOK

Production in the fourth quarter of 2005 is anticipated to average between 37,500 and 38,000 boe/d, reflecting contributions from the Celtic properties. For 2006, Baytex is targeting an average production level of 37,000 boe/d, comprising 23,000 bbl/d of heavy oil, 4,000 bbl/d of light oil and NGL and 60.0 mmcf/d of natural gas. The capital budget associated with this production target is projected to be $105 million on a preliminary basis. With the wealth of internal development projects, highlighted by optimization and exploitation at Celtic, continued testing and delineation at Seal, and natural gas and NGL development at Stoddart, Baytex is very confident in our ability to sustain our production efficiently. The outlook for financial sustainability is also positive in 2006. At 37,000 boe/d of production, moderate commodity prices of US$40.00 for WTI oil and US$6.50 for NYMEX gas would generate sufficient cash flow to fully fund cash distributions at the current rate and the 2006 capital budget. With outstanding operational and financial flexibility, Baytex is well positioned to continue delivering superior returns to our unitholders.

RECENT INDUSTRY DEVELOPMENT

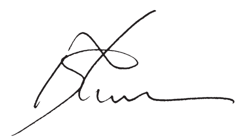
The federal government has recently made a number of pronouncements on tax and other issues relating to publicly listed flow-through entities (income trusts and limited partnerships). The resulting uncertainty has contributed to increased volatility and a significant loss of market value for the income trust sector.

The concerns of the government are the perceived loss of tax revenue due to taxable corporations converting to the income trust structure and a reduction in productivity as income trusts are more focused on maintaining distributions than economic growth. These concerns are not supported by Baytex's historical performance. In our ten-year history from 1993 to 2003 as a taxable corporation, Baytex did not pay any income taxes. Since conversion to an income trust in September 2003, Baytex has paid out $237 million in distributions to unitholders, of which approximately 85 percent is designated as taxable income. In terms of productivity and reinvestment, Baytex continues to be an active operator as we focus on replacing depletion through organic exploration and development activities. Since the trust conversion, we have invested $226 million in exploration and development expenditures, plus $256 million in the acquisition of assets. All of our investments during this period have been made exclusively in Canada. We believe that the trust structure enforces capital reinvestment discipline which is not always present in the oil and gas industry under a corporation structure, and that distribution of a portion of cash flow to unitholders provides the opportunity for reinvestments in other sectors of the economy. We are proud of our contributions to the Canadian economy, from the standpoints of tax revenue and productivity, as they are both substantial and transparent.

The income trust model has served as an effective vehicle for Canadians to invest for purposes of generating fixed income in a low interest rate environment and funding for retirement. Any potential tax levy or additional restrictions on income trusts would negatively affect their ability to maintain distributions and hence would likely further reduce their valuation. Baytex is a member of the Canadian Association of Income Funds ("CAIF") and will support CAIF in making submissions as part of the government's consultation process. In addition, Baytex strongly encourages unitholders to participate in the process so their opinions can be accounted for in the government's resolution of these important issues.

For written submission, send an e-mail to: trusts-fiducies@fin.gc.ca. To contact the Minister of Finance, you may write to The Honourable Ralph Goodale, Department of Finance, 140 O'Connor Street, Ottawa, Ontario K1A 0A6, or you may reach him at phone number (613) 996-4743, fax number (613) 996-9790, or via e-mail at goodale.R@parl.gc.ca. To contact your Member of Parliament, direct your comments to www.canada.gc.ca/directories/direct_e.html.

On behalf of the Board of Directors,



Raymond T. Chan, CA
President and Chief Executive Officer
November 7, 2005

Management's discussion and analysis ("MD&A"), dated November 8, 2005, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and the nine months ended September 30, 2005 and the audited consolidated financial statements and MD&A for the year ended December 31, 2004. 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.

Cash flow from operations is not a measure based on generally accepted accounting principles ("GAAP"), but is a financial term commonly used in the oil and gas industry. It represents cash generated from operating activities before changes in non-cash working capital, site restoration and reclamation expenditures, other assets and deferred credits. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers it a key measure as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions and capital investments.

PRODUCTION

Light oil production for the third quarter of 2005 more than doubled to 4,063 bbl/d from 1,890 bbl/d a year earlier. Heavy oil production decreased 9 percent to 20,061 bbl/d for the third quarter of 2005 compared to 22,083 bbl/d a year ago. Natural gas production increased by 26 percent to 63.9 mmcf/d for the third quarter of 2005 compared to 50.9 mmcf/d for the same period last year. The increase in light oil and natural gas production is due to the acquisitions completed in 2004 and the subsequent development of these assets. The decrease in heavy oil production is due to the lower number of wells drilled; 103.7 net oil wells were drilled in 2004 compared to 59.0 net oil wells drilled in the first nine months of 2005.

For the first nine months of 2005, light oil production increased by 92 percent to 3,782 bbl/d from 1,966 bbl/d for the same period last year. Heavy oil production for the first nine months of 2005 was down 11 percent to 20,326 bbl/d compared to 22,775 bbl/d for the same period in 2004. Natural gas production increased by 11 percent to average 60.9 mmcf/d for the first nine months of 2005 compared to 54.7 mmcf/d for 2004. The reasons for the differences in production are as discussed in the quarterly comparisons.

REVENUE

Petroleum and natural gas sales increased 43 percent to $154.9 million for the third quarter of 2005 from $108.2 million for the third quarter of 2004. For the first nine months, petroleum and natural gas sales increased by 25 percent to $384.6 million in 2005 from $308.9 million a year earlier.

For the per sales unit calculations, heavy oil sales for the three months ended September 30, 2005 were 84 barrels per day lower (three months ended September 30, 2004 – 88 barrels per day lower) than the production for the period due to inventory in transit under the Frontier supply agreement. The corresponding number for the nine months ended September 30, 2005 was a decrease of 22 barrels per day (nine months ended September 30, 2004 – a decrease of 14 barrels per day).

Three Months ended September 30

	2005		2004	
	thousands	**$/Unit[1]**	thousands	$/Unit[1]
Oil revenue (barrels)				
Light oil	**$ 22,146**	**59.24**	$ 9,152	52.63
Heavy oil	**83,430**	**45.39**	70,214	34.70
Derivative contracts loss	**(17,914)**	**(9.75)**	(24,716)	(12.21)
Total oil revenue	**87,662**	**39.64**	54,650	24.87
Natural gas revenue (mcf)	**49,353**	**8.39**	28,850	6.16
Total revenue (boe @ 6:1)	**$ 137,015**	**42.92**	$ 83,500	28.04

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/mcf.

Revenue from light oil for the third quarter of 2005 increased 142 percent from the same period a year ago due to a 115 percent increase in production and a 13 percent increase in wellhead prices. Revenue from heavy oil increased 19 percent as a 9 percent decrease in production was more than offset by a 31 percent increase in wellhead prices. Revenue from natural gas increased 71 percent as the result of a 36 percent increase in wellhead prices and a 26 percent increase in production.

Nine Months ended September 30

	2005		2004	
	thousands	**$/Unit[1]**	thousands	$/Unit[1]
Oil revenue (barrels)				
Light oil	**$ 54,870**	**53.15**	$ 25,743	47.78
Heavy oil	**206,379**	**37.23**	187,134	30.01
Derivative contracts loss	**(34,353)**	**(6.20)**	(50,554)	(8.11)
Total oil revenue	**226,896**	**34.51**	162,323	23.96
Natural gas revenue (mcf)	**123,335**	**7.42**	96,002	6.41
Total revenue (boe @ 6:1)	**$ 350,231**	**37.47**	$ 258,325	27.86

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/mcf.

For the first nine months of 2005, light oil revenue increased 113 percent from the same period last year due to an 11 percent increase in wellhead prices and a 92 percent increase in production. Revenue from heavy oil increased 10 percent due to a 24 percent increase in wellhead prices partially offset by an 11 percent decrease in production. Revenue from natural gas increased 28 percent compared to the first nine months of 2004, as production increased 11 percent combined with a price increase of 16 percent.

ROYALTIES

Total royalties increased to $22.6 million for the third quarter of 2005 from $17.1 million in 2004. This increase is reflective of the increase in total revenue. Total royalties for the third quarter of 2005 were 14.6 percent of sales compared to 15.8 percent of sales for the same period in 2004. For the third quarter of 2005, royalties were 14.4 percent of sales for light oil, 15.0 percent for heavy oil and 13.9 percent for natural gas. These rates compared to 12.7 percent, 14.7 percent and 19.4 percent, respectively, for the same period last year.

For the nine months ended September 30, 2005, royalties increased to $54.6 million from $48.6 million for the same period last year. Total royalties for the first three quarters of 2005 were 14.2 percent of sales, compared to 15.7 percent of sales for the corresponding period a year ago. For the first nine months of 2005, royalties were

14.7 percent of sales for light oil, 12.7 percent for heavy oil and 16.6 percent for natural gas. These rates compared to 13.3 percent, 13.2 percent and 21.4 percent, respectively, for the same period in 2004. The royalty rate for natural gas was lower in the current period due to a retroactive adjustment in the gas cost allowance used in the calculation of royalties.

OPERATING EXPENSES

Operating expenses for the third quarter of 2005 increased to $27.5 million from $22.1 million in the corresponding quarter last year. Operating expenses were $8.61 per boe for the third quarter of 2005 compared to $7.43 per boe for the third quarter of 2004. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services. For the third quarter of 2005, operating expenses were $10.40 per barrel of light oil, $9.49 per barrel of heavy oil and $1.05 per mcf of natural gas. The operating expenses for the same period a year ago were $11.67, $7.93 and $0.87, respectively.

Operating expenses for the first nine months of 2005 increased to $77.3 million from $64.8 million for the first three quarters in 2004. Operating expenses were $8.27 per boe for the first nine months of 2005 compared to $6.99 per boe for the corresponding period of the prior year. For the first three quarters of 2005, operating expenses were $10.06 per barrel of light oil, $8.98 per barrel of heavy oil and $1.03 per mcf of natural gas versus $9.96, $7.57 and $0.82, respectively, for the same period a year earlier.

TRANSPORTATION EXPENSES

Transportation expenses for the third quarter of 2005 were $5.3 million compared to $4.6 million for the third quarter of 2004. These expenses were $1.67 per boe for the third quarter of 2005 compared to $1.53 for the same period in 2004. Transportation expenses were $2.03 per barrel of oil and $0.14 per mcf of natural gas. The corresponding amounts for 2004 were $1.70 and $0.18, respectively.

Transportation expenses for the nine months ended September 30, 2005 were $16.4 million compared to $14.2 million for the first nine months of 2004. These expenses were $1.76 per boe in 2005 compared to $1.53 in 2004. Transportation expenses were $2.15 per barrel of oil and $0.14 per mcf of natural gas in the 2005 period, and $1.68 per barrel of oil and $0.18 per mcf of natural gas in the 2004 period.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses for the third quarter of 2005 decreased to $3.9 million from $4.0 million in 2004. On a per sales unit basis, these expenses were $1.21 per boe for the third quarter of 2005 compared to $1.34 per boe for 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either the third quarter of 2005 or 2004.

General and administrative expenses for the first nine months of 2005 were $11.4 million, compared to $11.2 million for the prior year. On a per sales unit basis, these expenses were $1.22 per boe in 2005 and $1.21 per boe in 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either 2005 or 2004.

UNIT-BASED COMPENSATION EXPENSE

Compensation expense related to the Trust's unit rights incentive plan was $2.5 million for the third quarter of 2005 compared to an expense of $3.2 million for the third quarter of 2004. For the nine months ended September 30, 2005, compensation expense was $8.2 million compared to $6.1 million for the same period in 2004.

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 is recorded as an increase in trust units with a corresponding reduction in contributed surplus.

On July 1, 2005, the Trust prospectively applied the fair value based method of estimating the compensation expense related to the unit rights plan. Previously, the Trust applied the intrinsic value methodology due to the difficulty of estimating certain key components of a fair value calculation under a new corporate structure, including unit price volatility, unit right exercise history and unit distribution patterns. As the Trust now has an extended period of trading and operating history, the Trust is better equipped to determine fair value estimates of unit rights at the grant date, and has applied the fair value methodology prospectively without restatement of prior periods.

As at September 30, 2005, the fair value calculation resulted in cumulative expense of $16.1 million compared to the $13.6 million recorded as cumulative compensation expense to June 30, 2005 under the intrinsic value method. Accordingly, the $2.5 million difference was recorded as compensation expense in the third quarter of 2005.

INTEREST EXPENSES

Interest expenses on long-term debt increased to $8.5 million for the third quarter of 2005 from $3.9 million for the same quarter last year, primarily due to the increased debt used to finance acquisitions completed in 2004, plus a gradual increase in interest rates.

For the first nine months of 2005, interest expenses on long-term debt were $23.4 million compared to $13.0 million for the same period last year. The increase is attributable to the same factors influencing the third quarter variance.

FOREIGN EXCHANGE

Foreign exchange gain in the third quarter of 2005 was $11.6 million compared to a gain of $13.8 million in the prior year. The gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8613 at September 30, 2005 compared to 0.8159 at June 30, 2005. The 2004 gain is based on translation at 0.7912 at September 30, 2004 compared to 0.7460 at June 30, 2004.

Foreign exchange gain for the first nine months of 2005 was $7.6 million compared to $5.1 million in the prior year. The 2005 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8613 at September 30, 2005 compared to 0.8308 at December 31, 2004. The 2004 gain is based on translation at 0.7912 at September 30, 2004 compared to 0.7737 at December 31, 2003.

DEPLETION, DEPRECIATION AND ACCRETION

The provision for depletion, depreciation and accretion increased to $40.8 million for the third quarter of 2005 compared to $39.4 million for the same quarter a year ago due to higher production volumes. On a sales-unit basis, the provision for the current quarter was $12.77 per boe compared to $13.23 per boe for the same quarter in 2004.

Depletion, depreciation and accretion increased to $125.5 million for the first three quarters of 2005 compared to $119.3 million for the same period last year. On a sales-unit basis, the provision for the current period was $13.43 per boe compared to $12.87 per boe for the same period a year earlier.

INCOME TAXES

Current tax expenses at $2.4 million for the third quarter of 2005 are unchanged from the same quarter a year ago. The current tax expense comprises $1.8 million of Saskatchewan Capital Tax and $0.6 million of Large Corporation Tax compared to $2.2 million and $0.2 million, respectively, in the corresponding period in 2004.

Current tax expenses were $6.3 million for the first nine months of 2005 compared to $7.2 million for the same period last year. The current tax expense comprises $4.8 million of Saskatchewan Capital Tax and $1.5 million of Large Corporation Tax compared to $5.4 million and $1.8 million, respectively, in 2004.

NET INCOME

Net income for the third quarter of 2005 was $38.2 million compared to a $12.6 million loss incurred in the third quarter in 2004. The favorable variance was the result of higher production, higher sales prices, and an unrealized gain on financial derivatives compared to a loss in the prior period.

Net income for the first nine months of 2005 was $40.2 million compared to a $28.3 million loss for the same period in 2004. The variance was primarily due to higher production, higher sales prices and lower loss in financial derivatives for the 2005 period.

LIQUIDITY AND CAPITAL RESOURCES

On June 6, 2005 the Trust issued $100 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 net proceeds were used to reduce outstanding bank indebtedness.

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 as at the date of issue. Issue costs are amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. As at September 30, 2005, $13.4 million principal amount of debentures had been tendered for conversion into trust units.

At September 30, 2005, total net debt (including working capital) was $506.8 million compared to $411.6 million at September 30, 2004 and $422.0 million at December 31, 2004. The increase was primarily due to the financing of properties acquired. The September 30, 2005 net debt included $21.2 million of notional liabilities based on the mark-to-market valuations of derivative contracts as at September 30, 2005.

CAPITAL EXPENDITURES

The Trust's total capital expenditures for these periods are summarized as follows:

	Nine Months ended September 30	
(thousands)	**2005**	2004
Land	**$ 6,030**	$ 4,888
Seismic	**4,378**	537
Drilling and completion	**69,008**	39,136
Equipment	**17,629**	18,092
Other	**2,401**	2,807
Total exploration and development	**99,446**	65,460
Property acquisitions	**72,424**	111,042
Property dispositions	**(2,990)**	(282)
Net capital expenditures	**$ 168,880**	$ 176,220

CONSOLIDATED BALANCE SHEETS

(thousands) (unaudited)	**September 30, 2005**	December 31, 2004
Assets		
Current assets		
Accounts receivable	**$ 70,334**	$ 41,154
Crude oil inventory	**9,214**	7,299
	79,548	48,453
Deferred charges and other assets	**9,725**	6,491
Petroleum and natural gas properties	**1,048,546**	1,009,933
Goodwill *(note 4)*	**37,755**	39,259
	$ 1,175,574	$ 1,104,136
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 74,772**	$ 72,976
Distributions payable to unitholders	**10,258**	9,981
Bank loan	**188,441**	161,444
Financial derivative contracts *(note 14)*	**21,226**	9,513
	294,697	253,914
Long-term debt *(note 5)*	**208,935**	216,583
Convertible debentures *(note 6)*	**82,695**	–
Asset retirement obligations *(note 7)*	**54,284**	73,297
Deferred obligations *(note 8)*	**4,969**	–
Future income taxes	**148,621**	164,909
	794,201	708,703
Non-controlling interest *(note 10)*	**11,948**	12,962
Unitholders' Equity		
Unitholders' capital *(note 9)*	**542,739**	515,728
Conversion feature of debentures *(note 6)*	**4,152**	–
Contributed surplus	**13,640**	7,494
Accumulated distributions	**(237,004)**	(146,445)
Accumulated income	**45,898**	5,694
	369,425	382,471
	$ 1,175,574	$ 1,104,136

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME (DEFICIT)

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands, except per unit data) (unaudited)	**2005**	2004	**2005**	2004
		(restated – note 3)		*(restated – note 3)*
Revenue				
Petroleum and natural gas sales	**$ 154,930**	$ 108,216	**$ 384,584**	$ 308,879
Royalties	**(22,617)**	(17,068)	**(54,629)**	(48,596)
Realized loss on financial derivatives	**(17,914)**	(24,716)	**(34,353)**	(50,554)
Unrealized gain (loss) on financial derivatives	**9,535**	(18,595)	**(11,713)**	(39,988)
	123,934	47,837	**283,889**	169,741
Expenses				
Operating	**27,490**	22,126	**77,304**	64,785
Transportation	**5,323**	4,570	**16,440**	14,164
General and administrative	**3,853**	4,005	**11,393**	11,174
Unit-based compensation *(note 11)*	**2,550**	3,161	**8,157**	6,149
Interest *(note 12)*	**8,490**	3,931	**23,384**	12,964
Foreign exchange gain	**(11,607)**	(13,765)	**(7,648)**	(5,128)
Depletion, depreciation and accretion	**40,772**	39,383	**125,548**	119,291
	76,871	63,411	**254,578**	223,399
Income (loss) before income taxes and non-controlling interest	**47,063**	(15,574)	**29,311**	(53,658)
Income taxes				
Current expense	**2,355**	2,359	**6,337**	7,150
Future expense (recovery)	**5,603**	(5,005)	**(18,162)**	(31,616)
	7,958	(2,646)	**(11,825)**	(24,466)
Income (loss) before non-controlling interest	**39,105**	(12,928)	**41,136**	(29,192)
Non-controlling interest *(notes 3 and 10)*	**(894)**	374	**(932)**	847
Net income (loss)	**38,211**	(12,554)	**40,204**	(28,345)
Accumulated income (deficit), beginning of period, as previously reported	**7,687**	(24,064)	**5,694**	(8,598)
Accounting policy change for non-controlling interest *(note 3)*	**–**	204	**–**	529
Accumulated income (deficit), beginning of period, as restated	**7,687**	(23,860)	**5,694**	(8,069)
Accumulated income (deficit), end of period	**$ 45,898**	$ (36,414)	**$ 45,898**	$ (36,414)
Net income (loss) per trust unit				
Basic	**$ 0.57**	$ (0.20)	**$ 0.60**	$ (0.45)
Diluted	**$ 0.51**	$ (0.20)	**$ 0.57**	$ (0.45)
Weighted average trust units				
Basic	**67,348**	62,805	**66,948**	62,302
Diluted	**77,840**	65,406	**70,868**	65,198

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands) (unaudited)	**2005**	2004	**2005**	2004
		(restated – note 3)		*(restated – note 3)*
Cash provided by (used in):				
Operating Activities				
Net income (loss)	**$ 38,211**	$ (12,554)	**$ 40,204**	$ (28,345)
Items not affecting cash:				
Unit-based compensation *(note 11)*	**2,550**	3,161	**8,157**	6,149
Amortization of deferred charges	**459**	2,794	**1,033**	8,376
Foreign exchange gain	**(11,607)**	(13,765)	**(7,648)**	(5,128)
Depletion, depreciation and accretion	**40,772**	39,383	**125,548**	119,291
Accretion on debentures	**155**	–	**201**	–
Unrealized loss (gain) on financial derivatives *(note 14)*	**(9,535)**	18,595	**11,713**	39,988
Future income tax (recovery)	**5,602**	(5,005)	**(18,162)**	(31,616)
Non-controlling interest *(note 10)*	**894**	(374)	**932**	(847)
Funds flow from operations	**67,501**	32,235	**161,978**	107,868
Change in non-cash working capital	**(6,392)**	(1,627)	**(23,605)**	(1,753)
Asset retirement expenditures	**(233)**	(665)	**(1,255)**	(1,550)
Decrease in deferred charges and other assets	**401**	53	**157**	159
	61,277	29,996	**137,275**	104,724
Financing Activities				
Issuance of convertible debentures *(note 6)*	**–**	–	**100,000**	–
Convertible debentures issue costs *(note 6)*	**–**	–	**(4,250)**	–
Increase in bank loan	**79,174**	113,843	**26,997**	113,843
Payments of distributions	**(30,241)**	(28,259)	**(90,282)**	(83,905)
Issue of trust units	**3,523**	210	**6,367**	210
	52,456	85,794	**38,832**	30,148
Investing Activities				
Petroleum and natural gas property expenditures	**(110,871)**	(20,673)	**(171,870)**	(65,460)
Corporate acquisitions	**–**	(111,042)	**–**	(111,042)
Disposal of petroleum and natural gas properties	**2,798**	713	**2,990**	282
Change in non-cash working capital	**(5,660)**	987	**(7,227)**	(10,600)
	(113,733)	(130,015)	**(176,107)**	(186,820)
Change in cash and short-term investments	**–**	(14,225)	**–**	(51,948)
Cash and short-term investments, beginning of period	**–**	16,008	**–**	53,731
Cash and short-term investments, end of period	**$ –**	$ 1,783	**$ –**	$ 1,783

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, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. 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 as described in note 2.

2. ACCOUNTING POLICIES

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2004. 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 consolidated financial statements and notes thereto for the year ended December 31, 2004.

3. CHANGES IN ACCOUNTING POLICY

Non-controlling Interest

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. 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. The presentation of the exchangeable shares at September 30, 2004 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

As a result of the adoption of EIC 151, net income was reduced in the first nine months of 2004 by $0.28 million (three months ended September 30, 2004 – increase of $0.05 million). As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-by-step acquisition where unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the nine months ended September 30, 2004, the adoption of EIC 151 resulted in a $15.5 million increase in petroleum and natural gas properties (three months ended September 30, 2004 – decrease of $0.03 million), a $5.9 million increase in future income taxes (three months ended September 30, 2004 – decrease of $0.12 million) and a $10.9 million increase in unitholders' capital (three months ended September 30, 2004 – $0.13 million).

Three Months and Nine Months Ended September 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

4. CORPORATE ACQUISITION

The Company has finalized its purchase allocation related to the acquisition made in 2004. Goodwill of $37.8 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities, including the future income tax liability.

5. LONG-TERM DEBT

	September 30, 2005	December 31, 2004
10.5% senior subordinated notes (US$247)	**$ 287**	$ 297
9.625% senior subordinated notes (US$179,699)	**208,648**	216,286
	$ 208,935	$ 216,583

6. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

On June 6, 2005, the Trust issued $100 million principal amount of 6.5 percent 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. Issue costs will be amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. 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.

Issuance on June 6, 2005	$ 100,000
Portion allocated to equity	(4,152)
Accretion of non-cash interest expense	201
Conversion into Trust Units	(13,354)
Balance, September 30, 2005	$ 82,695

7. ASSET RETIREMENT OBLIGATIONS

	Nine Months Ended	
	September 30, 2005	September 30, 2004
Balance, beginning of period	**$ 73,297**	$ 55,996
Liabilities incurred	**182**	2,116
Liabilities acquired	**8,169**	8,435
Liabilities settled	**(1,255)**	(1,550)
Accretion	**4,358**	3,360
Change in estimate	**(30,467)**	–
Balance, end of period	**$ 54,284**	$ 68,357

Three Months and Nine Months Ended September 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

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. The undiscounted amount of estimated cash flow required to settle the retirement obligations at September 30, 2005 is $225.8 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 1.5 percent.

8. DEFERRED OBLIGATIONS

The Company has future contractual processing obligations with respect to assets acquired. These obligations continue until October 2008.

9. UNITHOLDERS' CAPITAL

Trust Units

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

	Number of units	Amount
Balance, December 31, 2004	66,538	$ 515,728
Issued on conversion of exchangeable shares	358	5,279
Issued on conversion of debentures	905	13,354
Issued on exercise of trust unit rights	304	2,409
Transfer from contributed surplus on exercise of trust unit rights	–	2,011
Issued pursuant to distribution reinvestment program	279	3,958
Balance, September 30, 2005	68,384	$ 542,739

10. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five day trading period ending on the record date. The exchange ratio at September 30, 2005 was 1.33655 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

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 (loss) with a corresponding increase (decrease) to the non-controlling interest on the balance sheet.

	Number of exchangable shares	Amount
Balance, December 31, 2004	1,876	$ 12,962
Exchanged for trust units	(275)	(1,946)
Non-controlling interest in net income	–	932
Balance, September 30, 2005	1,601	$ 11,948

Three Months and Nine Months Ended September 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

11. TRUST UNIT RIGHTS

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% 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 units will result in an increase in the available number of trust units issuable under the plan, and any exercises of incentive rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust 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 allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions.

The Trust recorded compensation expense of $8.2 million for the nine months ending September 30, 2005 ($6.1 million in 2004).

On July 1, 2005, the Trust prospectively applied the fair value based method of estimating the compensation expense related to the unit rights plan. Previously, the Trust applied the intrinsic value methodology due to the difficulty of estimating certain key components of a fair value calculation under a new corporate structure, including unit price volatility, unit right exercise history, and cash distribution patterns. As the Trust now has an extended period of trading and operating history, the Trust is better equipped to determine fair value estimates of unit rights at the grant date and has applied the fair value methodology prospectively without restatement of prior periods.

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights. The following assumptions were used to arrive at the estimate of fair value as at September 30, 2005:

Expected annual rights' exercise price reduction	$ 1.80
Expected volatility	32.5%
Risk-free interest rate	4.5%
Expected life of option (years)	5

As at September 30, 2005, the fair value calculation resulted in cumulative expense of $16.1 million compared to the $13.6 million recorded as cumulative compensation expense to June 30, 2005 under the intrinsic value method. Accordingly, the $2.5 million difference was recorded as compensation expense in the third quarter of 2005. The $5.1 million remaining future value of the rights will be recognized in earnings over the remaining vesting period of the outstanding rights.

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

	Number of rights	Weighted average exercise price(1)
Balance, December 31, 2004	3,537	$ 9.60
Granted	579	$ 13.79
Exercised	(304)	$ 7.93
Cancelled	(177)	$ 9.38
Balance, September 30, 2005	3,635	$ 9.15

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

Three Months and Nine Months Ended September 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

The following table summarizes information about the outstanding rights at September 30, 2005:

Range of Exercise Prices	Number Outstanding at September 30, 2005	Weighted Average Remaining Term (years)	Weighted Average Exercise Price ($)	Number Exercisable at September 30, 2005	Weighted Average Exercise Price ($)
$5.86 to $7.47	1,929	2.97	7.09	1,149	7.09
$7.93 to $9.87	182	3.54	8.74	50	8.61
$10.00 to $11.47	974	4.12	10.96	94	10.10
$11.90 to $13.16	454	4.67	12.92	–	–
$13.58 to $16.37	96	4.69	14.95	–	–
$5.86 to $16.37	3,635	3.56	9.15	1,293	7.37

12. INTEREST EXPENSE

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	**2005**	2004
Credit facility charges	$ **1,472**	$ 201	$ **5,804**	$ 458
Amortization of deferred charge	**459**	267	**1,034**	794
Long-term debt	**6,559**	3,463	**16,546**	11,712
Total interest	$ **8,490**	$ 3,931	$ **23,384**	$ 12,964

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	**2005**	2004
Interest paid	$ **10,687**	$ 8,744	$ **23,887**	$ 19,297
Income taxes paid	$ **2,662**	$ 2,025	$ **6,943**	$ 15,077

14. FINANCIAL DERIVATIVE CONTRACTS

At September 30, 2005, the Trust had financial derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2005	3,000 bbl/d	US$35.00 – $42.40	WTI
Price collar	Calendar 2005	2,000 bbl/d	US$35.00 – $42.50	WTI
Price collar	Calendar 2005	1,000 bbl/d	US$35.00 – $42.70	WTI
Price collar	Calendar 2005	2,000 bbl/d	US$35.00 – $42.75	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI

Three Months and Nine Months Ended September 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

			Exchange Rate	
Foreign currency	Period	Amount	Floor	Cap
Collar	Calendar 2005	US$2,000,000 per month	CAD/USD $1.2140	CAD/USD $1.2500
Collar	Calendar 2005	US$3,000,000 per month	CAD/USD $1.2200	CAD/USD $1.2500
Collar	Calendar 2005	US$4,000,000 per month	CAD/USD $1.2150	CAD/USD $1.2500

Interest rate swap	Period	Principal	Rate
	November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

Under the CICA guideline for hedge accounting, the Trust's financial derivative contracts for oil and foreign currency do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Edward Chwyl
Chairman
Baytex Energy Trust
Independent Businessman

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W. A. Blake Cassidy
Retired Banker

Raymond T. Chan
President and CEO
Baytex Energy Trust

Naveen Dargan
Independent Businessman

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

Dale O. Shwed
President and CEO
Crew Energy Inc.

OFFICERS

Raymond T. Chan
President and CEO

W. Derek Aylesworth
Chief Financial Officer

Randal J. Best
Vice President, Corporate Development

Ralph W. Gibson
Vice President, Marketing

Anthony W. Marino
Chief Operating Officer

Shannon M. Gangl
Secretary
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AUDITORS

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BANKERS

The Toronto-Dominion Bank
BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: BTE.UN

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGLs	natural gas liquids

ADVISORY

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow, debt levels and cash distribution practices.The reader is cautioned that assumptions used in the preparation of such information, 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; competitive action by other companies, fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Trust's areas of operations; and other factors, many of which are beyond the control of the Trust. 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.

BAYTEX

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