BAYTEX

ENERGY TRUST

Q3

THIRD QUARTER REPORT

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2004

HIGHLIGHTS

Baytex Energy Trust is pleased to report its operating and financial results for the nine months ended September 30, 2004. The Trust commenced operations on September 2, 2003 as a result of the reorganization of Baytex Energy Ltd. As the Trust is considered the successor organization to Baytex Energy Ltd. for reporting purposes, comparative information is provided for the three months and nine months ended September 30, 2003. Pursuant to the Plan of Arrangement effecting the reorganization, certain assets were not transferred to the Trust. Accordingly, results of the corresponding periods in 2003 and 2004 are not entirely comparable.

Financial	Three Months Ended			Nine Months Ended	
($ thousands, except per unit amounts)	**September 30, 2004**	June 30, 2004	September 30, 2003	**September 30, 2004**	September 30, 2003
Petroleum and natural gas sales	**108,216**	104,517	98,692	**308,879**	313,496
Cash flow from operations(1)	**32,235**	36,944	19,975	**107,868**	108,054
Per unit – basic	**0.50**	0.57	0.36	**1.66**	2.00
– diluted	**0.49**	0.57	0.36	**1.65**	2.00
Cash distributions declared	**28,266**	28,237	–	**84,207**	–
Per unit	**0.45**	0.45	–	**1.35**	–
Net income (loss)	**(12,604)**	(11,170)	(46,245)	**(28,070)**	26,188
Per unit – basic	**(0.19)**	(0.17)	(0.84)	**(0.43)**	0.48
– diluted	**(0.19)**	(0.17)	(0.84)	**(0.43)**	0.48
Exploration and development	**20,686**	15,975	42,417	**65,460**	157,103
Acquisitions – net of dispositions	**110,316**	–	669	**110,760**	(131,042)
Total capital expenditures	**131,002**	15,975	43,086	**176,220**	26,061
Long-term notes				**227,434**	242,999
Bank loan				**113,843**	–
Working capital deficiency				**70,335**	24,806
Total net debt				**411,612**	267,805
Operating					
Daily production					
Light oil (bbls/d)	**1,890**	1,952	1,989	**1,966**	2,371
Heavy oil (bbls/d)	**22,083**	22,927	25,123	**22,775**	23,746
Total oil (bbls/d)	**23,974**	24,879	27,112	**24,741**	26,117
Natural gas (mmcf/d)	**50.9**	57.2	61.8	**54.7**	64.4
Oil equivalent (boe/d @ 6:1)	**32,454**	34,411	37,412	**33,853**	36,851
Average prices (before hedging)					
WTI oil (US$/bbl)	**43.88**	38.32	30.20	**39.11**	30.99
Edmonton par oil ($/bbl)	**56.32**	50.59	40.94	**50.83**	44.33
BTE light oil ($/bbl)	**52.63**	47.55	35.40	**47.78**	40.73
BTE heavy oil ($/bbl)	**34.69**	29.21	25.68	**30.00**	27.60
BTE total oil ($/bbl)	**36.11**	30.63	26.39	**31.41**	28.83
BTE natural gas ($/mcf)	**6.16**	6.61	5.79	**6.41**	6.44
BTE oil equivalent ($/boe)	**36.34**	33.12	28.69	**33.31**	31.73
Trust Unit Information					
Unit Price					
High	**13.13**	12.60	12.74	**13.13**	12.74
Low	**11.65**	11.00	9.19	**9.78**	8.10
Close	**12.88**	12.00	9.50	**12.88**	9.50
Units Traded	**13,696**	21,983	37,701	**70,457**	96,674
Units Outstanding	**65,044**	64,938	58,037	**65,044**	58,037
Foreign Ownership	**33%**	31%	–	**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.

CORPORATE UPDATE

On September 22, 2004, Baytex completed the acquisition of a Calgary-based private oil and gas company for a cash consideration of $109 million. This acquisition brings approximately 3,000 boe/d of 65 percent gas-weighted production, located mainly in two focused areas of southern Alberta: Sedalia/Garden Plains and Turin/Parkland, with half of this production complementary to Baytex's existing operations. This acquisition also adds significant development inventory to Baytex's light oil and natural gas portfolio, with numerous drilling and recompletion opportunities as well as 110,000 net acres of undeveloped land. Consequently, Baytex is better positioned to maintain its production mix in the future through the development of its heavy oil and non-heavy oil prospects.

OPERATIONS REVIEW

Production operations and capital programs continued to be hampered by inclement weather and wet field conditions through the third quarter. Capital expenditures, excluding acquisitions, were limited to $20.7 million in the third quarter of 2004. For the nine months ended September 30, 2004, capital spending on exploration and development activities totalled $65.5 million. It is expected that capital spending for the year will be in the $85 million to $90 million range as compared to the original budget of $105 million for the year.

During the third quarter of 2004, Baytex participated in the drilling of 34 (34.0 net) wells, resulting in 29 (29.0 net) oil wells, one (1.0 net) gas well and four (4.0 net) dry holes. In addition, three wells were drilled and cased by other operators through farm-in arrangements on Baytex lands. For the first nine months of 2004, Baytex's drilling activities placed it as the 23rd (5th amongst all energy trusts) most active operator in Alberta and 14th (2nd amongst all energy trusts) most active operator in Saskatchewan.

Production for the third quarter of 2004 averaged 32,454 boe/d compared to 34,411 boe/d in the previous quarter. The decrease is primarily due to the aforementioned unfavourable field conditions and curtailed capital programs. As the acquisition was completed near the end of the quarter, its impact on the reported production level was nominal.

FINANCIAL REVIEW

Cash flow from operations for the third quarter of 2004 was $32.2 million compared to $36.9 million for the previous quarter. This decrease is mainly attributable to losses from crude oil hedging contracts, where Baytex incurred total hedging losses of $24.7 million in the third quarter compared to $16.4 million in the second quarter. WTI oil on NYMEX averaged US$43.88 per barrel during the third quarter, 15 percent higher than the second-quarter average of US$38.32. Baytex has financial derivative contracts covering 15,000 bbls/d in 2004 with an average cap price of US$29.75. This level of hedging has a negative overall impact on Baytex's cash flow when WTI price escalates beyond US$35.00. These restrictive contracts are due to expire on December 31, 2004.

Baytex incurred a net loss of $12.6 million for the third quarter and a net loss of $28.1 million for the first nine months of 2004 entirely due to the new accounting guideline requiring the inclusion of the mark-to-market value of certain derivative contracts as of the balance sheet date. The resulting effect is $21.1 million of unrealized losses for the third quarter and $47.6 million for the nine months being included in the income statement and $50.1 million of notional liabilities being included in the balance sheet as of September 30, 2004. These losses have no impact on reported cash flow and their accounting treatment will continue to create unpredictable fluctuations in Baytex's net income due to the volatility of underlying commodity prices.

OUTLOOK

Baytex is targeting average production in the range of 34,000 boe/d to 35,000 boe/d for the remainder of 2004 and in 2005. Monthly distributions have been maintained at $0.15/unit since the inception of the Trust. For 2004, these distributions are estimated to represent approximately 75 percent to 80 percent of cash flow mainly due to the negative impact of the crude oil hedging contracts. For 2005, the hedged volume has been reduced to 8,000 bbls/d as compared to 15,000 bbls/d in 2004, and the average cap price, has been increased to US$42.55 from US$29.75 in 2004. This lower level of hedging in 2005 allows Baytex to benefit from any oil price increase beyond the cap price, while providing substantial downside protection. Based on the Trust's production target and commodity price outlook, the monthly distribution of $0.15/unit could approximate only 50 percent of distributable cash flow in 2005. Baytex plans to use the remaining cash flow to fund its internal capital programs and to repay part of the bank debt drawn for the third-quarter-2004 acquisition.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
November 8, 2004

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.

Management's discussion and analysis ("MD&A"), dated November 8, 2004, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and the nine months ended September 30, 2004, and the audited consolidated financial statements and MD&A for the year ended December 31, 2003. 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.

On September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in western Canada. The results of operations from the date of acquisition of the private company have been included in consolidated financial statements for the three months and the nine months ended September 30, 2004.

Production

Light oil production for the third quarter of 2004 decreased by five percent to 1,890 bbls/d from 1,989 bbls/d a year earlier. Heavy oil production decreased 12 percent to 22,083 bbls/d for the third quarter of 2004, compared to 25,123 bbls/d a year ago. Natural gas production decreased by 18 percent to 50.9 mmcf/d for the third quarter of 2004, compared to 61.8 mmcf/d for the same period last year. The production decrease is due to the impact of wet weather on field operations, reduced capital spending and the transfer of certain properties to Crew under the Plan of Arrangement.

For the first three quarters of 2004, light oil production decreased by 17 percent to 1,966 bbls/d from 2,371 bbls/d for the same period last year. Heavy oil production for the first nine months of 2004 was down four percent to 22,775 bbls/d compared to 23,746 bbls/d for the same period in 2003. Natural gas production decreased by 15 percent to average 54.7 mmcf/d for the first nine months of 2004, compared to 64.4 mmcf/d for 2003. In addition to the factors which affected the third-quarter production, the 2004 production was also reduced by the property sale in Ferrier in March 2003.

Revenue

Petroleum and natural gas sales increased 10 percent to $108.2 million for the third quarter of 2004 from $98.7 million for the third quarter of 2003. For the first nine months, petroleum and natural gas sales decreased by one percent to $308.9 million in 2004 from $313.5 million a year earlier.

For the per-sales-unit calculations, heavy oil sales for the three months ended September 30, 2004 were 88 bbls/d (three months ended September 30, 2003 - 24 bbs/d) 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, 2004 was a decrease of 14 bbls/d (nine months ended September 30, 2003 – 665 bbls/d).

Revenue from light oil for the third quarter of 2004 increased 41 percent from the same period a year ago, due to a five percent decrease in production and a 49 percent increase in wellhead prices. Revenue from heavy oil increased 18 percent as a 12 percent decrease in production was offset by a 35 percent increase in wellhead prices. Revenue from natural gas decreased 12 percent as the six percent increase in wellhead prices was offset by an 18 percent decrease in production.

For the first nine months of 2004, light oil revenue decreased two percent from the same period last year due to an 18 percent increase in wellhead prices and a 17 percent decrease in production. Revenue from heavy oil increased eight percent due to an increase in wellhead prices. Revenue from natural gas decreased 15 percent as production decreased 15 percent compared to the first three quarters of 2003.

Royalties

Total royalties increased to $17.1 million for the third quarter of 2004 from $15.3 million in 2003. Total royalties for the third quarter of 2004 were 15.8 percent of sales compared to 15.5 percent of sales for the same period in 2003. For the third quarter of 2004, royalties were 12.7 percent of sales for light oil, 14.7 percent for heavy oil and 19.4 percent for natural gas. These rates compared to 16.8 percent, 12.9 percent and 19.7 percent, respectively, for the same period last year.

For the nine months ended September 30, 2004, royalties decreased to $48.6 million from $53.7 million for the same

Revenue

	Three Months Ended September 30			
	2004		2003	
	$000s	$/Unit (1)	$000s	$/Unit (1)
Oil revenue (barrels)				
Light oil	**9,152**	**52.63**	6,479	35.40
Heavy oil	**70,214**	**34.69**	59,293	25.68
Derivative contracts loss	**(24,716)**	**(11.25)**	(6,899)	(2.77)
Total oil revenue	**54,650**	**24.87**	58,873	23.62
Natural gas revenue (mcf)	**28,850**	**6.16**	32,919	5.79
Total revenue (boe @ 6:1)	**83,500**	**28.04**	91,792	26.69

	Nine Months Ended September 30			
	2004		2003	
	$000s	$/Unit (1)	$000s	$/Unit (1)
Oil revenue (barrels)				
Light oil	**25,743**	**47.78**	26,368	40.73
Heavy oil	**187,134**	**30.00**	173,923	27.60
Derivative contracts loss	**(50,554)**	**(7.46)**	(26,859)	(3.87)
Total oil revenue	**162,323**	**23.96**	173,432	24.96
Natural gas revenue (mcf)	**96,002**	**6.41**	113,206	6.44
Total revenue (boe @ 6:1)	**258,325**	**27.86**	286,638	29.02

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

period last year. Total royalties for the first three quarters of 2004 were 15.7 percent of sales, a decrease from 17.1 percent of sales for the corresponding period a year ago, due to an increased percentage of total production from heavy oil which has a lower royalty rate. For the first nine months of 2004, royalties were 13.3 percent of sales for light oil, 13.2 percent for heavy oil and 21.4 percent for natural gas. These rates compared to 18.1 percent, 13.6 percent and 22.4 percent, respectively, for the same period in 2003.

Operating Expenses

Operating expenses for the third quarter of 2004 decreased to $22.1 million from $23.2 million in the corresponding quarter last year. Operating expenses were $7.43 per boe for the third quarter of 2004, compared to $6.75 per boe for the third quarter of 2003. The increase in operating expenses per boe was due to lower production during 2004 and an inflationary cost environment. For the third quarter of 2004, operating expenses were $11.67 per barrel of light oil, $7.93 per barrel of heavy oil and $0.87 per mcf of natural gas. The operating expenses for the same period a year ago were $11.31, $7.10 and $0.84, respectively.

Operating expenses for the first three quarters of 2004 increased to $64.8 million from $64.0 million for the first three quarters in 2003. Operating expenses were $6.99 per boe for the first nine months of 2004 compared to $6.48 per boe for the corresponding period of the prior year. For the first three quarters of 2004, operating expenses were $9.96 per barrel of light oil, $7.57 per barrel of heavy oil and $0.82 per mcf of natural gas versus $7.73, $7.31 and $0.73, respectively, for the same period a year earlier.

Transportation Expenses

Transportation expenses for the third quarter of 2004 were $4.6 million compared to $4.6 million for the third quarter of 2003. These expenses were $1.53 per boe for the third quarter of 2004 compared to $1.34 for the same period in 2003. Transportation expenses were $1.70 per barrel of oil and $0.18 per mcf of natural gas. The corresponding amounts for 2003 were $1.45 and $0.17, respectively.

Transportation expenses for the nine months ended September 30, 2004 were $14.2 million compared to $13.1 million for the first nine months of 2003. These expenses were $1.53 per boe in 2004 compared to $1.33 in 2003. Transportation expenses were $1.68 per barrel of oil and $0.18 per mcf of natural gas in the 2004 period, and $1.48 per barrel of oil and $0.16 per mcf of natural gas in the 2003 period.

General and Administrative Expenses

General and administrative expenses for the third quarter of 2004 were $4.0 million compared to $2.0 million in 2003. On a per-sales-unit basis, these expenses were $1.34 per boe for the third quarter of 2004 compared to $0.58 per boe for 2003. In accordance with our full-cost accounting policy, no expenses were capitalized for the third quarter of 2004 compared to $1.0 million of expenses capitalized in the third quarter of 2003. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

General and administrative expenses for the first three quarters of 2004 were $11.2 million, compared to $5.4 million for the prior year. On a per-sales-unit basis, these expenses were $1.21 per boe in 2004 and $0.54 per boe in 2003. In accordance with our full-cost accounting policy, no expenses have been capitalized in 2004, while $4.4 million of expenses were capitalized in the first nine months of 2003.

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $3.2 million for the third quarter of 2004. No compensation expense was incurred in the third quarter of 2003.

For the nine months ended September 30, 2004, compensation expense was $6.2 million compared to $0.5 million for the same period in 2003. The 2004 compensation expense was based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements. The compensation expense for 2003 was based on the fair value of the stock options outstanding prior to the Plan of Arrangement.

Interest Expenses

Interest expenses on long-term debt decreased to $3.9 million for the third quarter of 2004 from $6.6 million for the same quarter last year.

For the first nine months of 2004, interest expenses on long-term debt were $13.0 million compared to $18.4 million for the same period last year. The decrease is due to the redemption of the Company's senior secured notes in May 2003, and the stronger Canadian currency as interest on the long-term notes is denominated in U.S. dollars.

Foreign Exchange

The foreign exchange gain in the third quarter of 2004 was $13.8 million compared to a gain of $1.5 million in the prior year. This amount includes the foreign exchange gain on the Company's senior secured notes until their redemption in May 2003. The gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7912 at September 30, 2004 compared to 0.7460 at June 30, 2004. The 2003 gain is based on translation at 0.7405 at September 30, 2003 compared to 0.7378 at June 30, 2003.

The foreign exchange gain for the first nine months of 2004 was $5.1 million compared to a gain of $41.7 million in the prior year. The 2004 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7912 at September 30, 2004 compared to 0.7737 at December 31, 2003. The 2003 gain is based on translation at 0.7405 at September 30, 2003 compared to 0.6331 at December 31, 2002.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion increased to $38.9 million for the third quarter of 2004 compared to $28.7 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was $13.05 per boe compared to $8.35 per boe for the same quarter in 2003 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument ("NI") 51-101.

Depletion, depreciation and accretion increased to $117.5 million for the first three quarters of 2004 compared to $80.5 million for the same period last year. On a sales-unit basis, the provision for the current period was $12.67 per boe compared to $8.15 per boe for the same period a year earlier.

Income Taxes

Current tax expenses were $2.4 million for the third quarter of 2004 compared to $1.8 million for the same quarter a year ago. The current tax expense is comprised of $2.2 million of Saskatchewan Capital Tax and $0.2 million of Large Corporation Tax compared to $1.7 million and $0.1 million, respectively, in the corresponding period in 2003.

Current tax expenses were $7.2 million for the first three quarters of 2004 compared to $6.2 million for the same period last year. The current tax expense is comprised of $5.4 million of Saskatchewan Capital Tax and $1.8 million of Large Corporation Tax compared to $5.3 million and $0.9 million, respectively, in 2003.

Net Income (Loss)

Net loss for the third quarter of 2004 of $12.6 million was the result of increased charges for depletion, depreciation and accretion, and the losses on financial derivatives. Net loss for the third quarter of 2003 was impacted by the costs on redemption of the notes and the reorganization costs incurred for the Trust conversion in September 2003, which were offset by the foreign exchange gain for the period. Net loss for the first nine months of 2004 was $28.1 million and was impacted by the same reasons noted in the third-quarter comparison.

Liquidity and Capital Resources

At September 30, 2004, total net debt (including working capital) was $411.6 million compared to $267.8 million at September 30, 2003 and $213.6 million at December 31, 2003. The $411.6 million net debt included $50.1 million of notional liabilities based on the mark-to-market valuations of derivative contracts as at September 30, 2004. At the end of September 2004, $113.8 million was outstanding under the bank credit facilities, as the corporate acquisition in September 2004 was financed using the existing bank credit facilities. Subsequent to September 30, 2004, the bank credit facilities have been increased to a total of $205 million.

Capital Expenditures

Exploration and development expenditures decreased to $65.5 million for the first three quarters of 2004 compared to $157.1 million for the same period last year. The lower capital expenditures reflect a different business plan since the conversion to an income trust. Capital programs were hampered by inclement weather and wet field conditions throughout the third quarter. For the nine months ended September 30, 2004, the Trust participated in the drilling of 106 (104.9 net) wells, resulting in 79 (78.6 net) oil wells, 11 (10.8 net) gas wells, seven (6.5 net) service wells and nine (9.0 net) dry holes compared to prior-year activities of 235 (217.4 net) wells, including 147 (136.7 net) oil wells, 66 (60.4 net) gas wells, four (3.3 net) service wells and 18 (17.0 net) dry holes. It is expected that capital spending for the year will be in the $85 million to $90 million range as compared to the original budget of $105 million for the year. On September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in western Canada.

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

Capital Expenditures

	Nine Months Ended September 30	
($ thousands)	**2004**	2003
Land	**4,888**	12,782
Seismic	**537**	5,246
Drilling and completion	**39,136**	97,564
Equipment	**18,092**	35,312
Other	**2,807**	6,199
Total exploration and development	**65,460**	157,103
Corporate acquisition	**111,042**	–
Property acquisitions	**–**	6,233
Property dispositions	**(282)**	(137,275)
Net capital expenditures	**176,220**	26,061

(thousands) (unaudited)	**September 30, 2004**	December 31, 2003 *(restated – see note 3)*
Assets		
Current assets		
Cash and short-term investments	**$ 1,783**	$ 53,731
Accounts receivable	**43,507**	48,608
Financial derivative contracts *(note 10)*	**2,497**	–
Crude oil inventory	**6,511**	5,900
	54,298	108,239
Deferred derivative loss *(note 3)*	**2,528**	–
Deferred charges and other assets	**6,811**	7,764
Petroleum and natural gas properties	**925,281**	862,350
Goodwill *(note 4)*	**38,337**	–
	$ 1,027,255	$ 978,353
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 62,613**	$ 80,126
Distributions payable to Unitholders	**9,425**	9,123
Bank loan	**113,843**	–
Financial derivative contracts *(note 10)*	**52,595**	–
	238,476	89,249
Long-term debt *(note 5)*	**227,434**	232,562
Asset retirement obligations *(note 6)*	**68,357**	55,996
Future income taxes	**167,696**	169,336
	701,963	547,143
Unitholders' Equity		
Unitholders' capital *(note 8)*	**459,839**	446,594
Exchangeable shares *(note 8)*	**13,337**	26,372
Contributed surplus	**6,373**	224
Accumulated distributions	**(117,589)**	(33,382)
Accumulated deficit	**(36,668)**	(8,598)
	325,292	431,210
	$ 1,027,255	$ 978,353

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATIVE DEFICIT

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands, except per unit data) (unaudited)	**2004**	2003	**2004**	2003
		(restated – note 3)		*(restated – note 3)*
Revenue				
Petroleum and natural gas sales	**$ 108,216**	$ 98,692	**$ 308,879**	$ 313,496
Royalties	**(17,068)**	(15,253)	**(48,596)**	(53,677)
Realized loss on financial derivatives	**(24,716)**	(6,899)	**(50,554)**	(26,859)
Unrealized loss on financial derivatives	**(18,595)**	–	**(39,988)**	–
	47,837	76,540	**169,741**	232,960
Expenses				
Operating	**22,126**	23,233	**64,785**	63,968
Transportation *(note 3)*	**4,570**	4,593	**14,164**	13,102
General and administrative	**4,005**	1,993	**11,174**	5,357
Unit-based compensation *(note 9)*	**3,161**	–	**6,149**	515
Interest *(note 5)*	**3,931**	6,588	**12,964**	18,375
Reorganization costs	**–**	18,642	**–**	18,642
Costs on redemption of notes	**–**	40,003	**–**	44,771
Foreign exchange gain	**(13,765)**	(1,469)	**(5,128)**	(41,664)
Depletion, depreciation and accretion	**38,866**	28,722	**117,500**	80,524
	62,894	122,305	**221,608**	203,590
Income (loss) before income taxes	**(15,057)**	(45,765)	**(51,867)**	29,370
Income taxes				
Current expense	**2,359**	1,757	**7,150**	6,213
Future recovery *(note 7)*	**(4,812)**	(1,277)	**(30,947)**	(3,031)
	(2,453)	480	**(23,797)**	3,182
Net income (loss)	**$ (12,604)**	$ (46,245)	**(28,070)**	26,188
Accumulated deficit, beginning of period, as previously reported			**(351)**	(38,489)
Accounting policy change for asset retirement obligations *(note 3)*			**(8,247)**	(5,424)
Accumulated deficit, beginning of period, as restated			**(8,598)**	(43,913)
Accumulated deficit, end of period			**$ (36,668)**	$ (17,725)
Net income (loss) per trust unit				
Basic	**$ (0.19)**	$ (0.84)	**$ (0.43)**	$ 0.48
Diluted	**$ (0.19)**	$ (0.84)	**$ (0.43)**	$ 0.48
Weighed average units				
Basic	**64,995**	55,094	**64,954**	54,023
Diluted	**65,406**	55,052	**65,198**	54,025

See accompanying notes to the consolidated financial statements.

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands) (unaudited)	**2004**	2003	**2004**	2003
		(restated – note 3)		*(restated – note 3)*
Cash provided by (used in):				
Operating Activities				
Net income (loss)	**$ (12,604)**	$ (46,245)	**$ (28,070)**	$ 26,188
Items not affecting cash:				
Unit-based compensation *(note 8)*	**3,161**	–	**6,149**	515
Amortization of deferred charges	**2,794**	241	**8,376**	751
Costs on redemption of notes *(note 5)*	**–**	40,003	**–**	44,771
Foreign exchange gain	**(13,765)**	(1,469)	**(5,128)**	(41,664)
Depletion, depreciation and accretion	**38,866**	28,722	**117,500**	80,524
Unrealized loss on financial derivatives *(note 10)*	**18,595**	–	**39,988**	–
Future income tax recovery	**(4,812)**	(1,277)	**(30,947)**	(3,031)
Cash flow from operations	**32,235**	19,975	**107,868**	108,054
Change in non-cash working capital	**(1,627)**	10,920	**(1,753)**	(2,962)
Site restoration and reclamation expenditures	**(665)**	(152)	**(1,550)**	(619)
Decrease (increase) in deferred charges and other assets	**53**	(6,753)	**159**	(7,229)
	29,996	23,990	**104,724**	97,244
Financing Activities				
Redemption of senior secured notes *(note 5)*	**–**	–	**–**	(89,950)
Increase in bank loan	**113,843**	–	**113,843**	–
Increase in deferred charges and other assets	**–**	(76)	**–**	(2,213)
Payments of distributions	**(28,259)**	–	**(83,905)**	–
Issue of trust units	**210**	–	**210**	–
Issue of common shares	**–**	33,154	**–**	37,050
	85,794	33,078	**30,148**	(55,113)
Investing Activities				
Petroleum and natural gas property expenditures	**(20,673)**	(43,051)	**(65,460)**	(163,336)
Corporate acquisition *(note 4)*	**(111,042)**	–	**(111,042)**	–
Disposal of petroleum and natural gas properties	**713**	(35)	**282**	137,275
Change in non-cash working capital	**987**	(10,211)	**(10,600)**	3,039
	(130,015)	(53,297)	**(186,820)**	(23,022)
Change in cash and short-term investments	**(14,225)**	3,771	**(51,948)**	19,109
Cash and short-term investments, beginning of period	**16,008**	19,436	**53,731**	4,098
Cash and short-term investments, end of period	**$ 1,783**	$ 23,207	**$ 1,783**	$ 23,207

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, 2003, except as described in note 3. 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, 2003.

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the carrying amount to the fair value of the reporting entity. If the fair value of the Trust is less than the book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied value of goodwill. Any excess of the book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

3. CHANGES IN ACCOUNTING POLICY

Unit-Based Compensation

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Previously reported amounts for 2003 have been restated to give effect to the standard as at January 1, 2003. Compensation expense of $0.52 million was recorded for the nine months ended September 30, 2003 (three months ended September 30, 2003 - nil) for all stock options granted by the Company since January 1, 2003, with a corresponding amount recorded as contributed surplus (see note 9).

Three Months and Nine Months Ended September 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

Full Cost Accounting

In 2003, the CICA issued Accounting Guideline 16, Oil and Gas Accounting - Full Cost (AcG-16). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition test which compares the undiscounted future cash flow from proved reserves plus the cost, less impairment of unproven properties, to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the carrying amount of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust:

	2004	2005	**2006**	2007	2008
WTI (US$/bbl)	29.63	26.80	25.76	26.14	26.53
AECO (CAD$/mcf)	6.03	5.36	4.80	4.91	4.98

Asset Retirement Obligations

Effective January 1, 2004, the Trust adopted the CICA Section 3110, "Asset Retirement Obligations". This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative nine months ended September 30, 2003 decreased by $2.5 million, net of future income tax of $0.5 million (three months ended September 30, 2003 - $0.7 million, net of future income tax of $0.4 million). At September 30, 2003 the asset retirement obligations balance increased by $32.3 million to $54.7 million, the petroleum and natural gas assets balance increased by $19.6 million to $880.8 million and the future tax liability decreased by $4.7 million to $180.7 million. The opening 2003 accumulated deficit increased by $5.4 million (net of future income tax of $0.8 million). There was no impact on cash flow as a result of adopting this policy (see note 6).

Financial Derivative Contracts

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 "Hedging Relationships" (AcG-13) for accounting for derivative contracts. This guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC 128) also became effective. EIC 128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC 128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

As of January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance is being recognized in income over the term of the previously designated hedged item. At September 30, 2004, the Trust recorded a liability of $52.6 million and an asset of $2.5 million on the mark-to-market value of the non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from January 1, 2004 to September 30, 2004 has been recorded as an unrealized loss on non-hedging financial derivatives of $40.0 million in the consolidated statement of operations (note 10).

Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the nine months ended September 30, 2004 both increased by $14.2 million (2003 - $13.1 million) and for the three months ended September 30, 2004 increased by $4.6 million (2003 - $4.6 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

4. CORPORATE ACQUISITION

Effective September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in western Canada. The acquisition was financed with the Company's credit facilities. The transaction was accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below. The Company has not yet completed its final valuation of the assets acquired and liabilities assumed and, therefore, the purchase price allocation may be subject to change. Subsequent to the acquisition, the private company was amalgamated with the Company.

Three Months and Nine Months Ended September 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

Petroleum and natural gas properties	$ 109,777
Goodwill	38,337
Working capital	1,447
Capital lease obligation	(777)
Asset retirement obligation	(8,435)
Future income taxes	(29,307)
Total net assets acquired	$ 111,042

Financed by:

Cash	$ 110,822
Costs associated with acquisition	220
Total purchase price	$ 111,042

Goodwill of $38.3 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, 2004	December 31, 2003
10.5% senior subordinated notes (US$247)	**$ 312**	$ 319
9.625% senior subordinated notes (US$179,699)	**227,122**	232,243
	$ 227,434	$ 232,562

Interest Expense

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Credit facility charges	**$ 201**	$ 561	**$ 458**	$ 561
Amortization of deferred charge	**267**	241	**794**	751
Long-term debt	**3,463**	5,786	**11,712**	17,063
Total interest	**$ 3,931**	$ 6,588	**$ 12,964**	$ 18,375

Three Months and Nine Months Ended September 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

6. ASSET RETIREMENT OBLIGATIONS

	September 30, 2004	December 31, 2003
Balance, beginning of period	$ 55,996	$ 52,244
Liabilities incurred	2,116	4,010
Liabilities settled	(1,550)	(880)
Acquisition of liabilities	8,435	–
Disposition of liabilities	–	(3,335)
Accretion	3,360	3,957
Balance, end of period	$ 68,357	$ 55,996

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, 2004 is $115.8 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.

7. INCOME TAXES

Future income tax expense for the period ended September 30, 2004 included a non-recurring adjustment to future income taxes resulting from a decrease to the Alberta corporate income tax rate from 12.5 percent to 11.5 percent.

8. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Trust Units

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

Trust Units	# of units	Amount
Balance December 31, 2003	60,821	$ 446,594
Issued on conversion of exchangeable shares	1,984	13,035
Issued on exercise of trust unit rights	26	210
Balance September 30, 2004	62,831	$ 459,839

Exchangeable Shares

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, 2004 was 1.17454 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded.

Three Months and Nine Months Ended September 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

Exchangeable Shares	# of shares	Amount
Balance December 31, 2003	3,725	$ 26,372
Exchanged for trust units	(1,841)	(13,035)
Balance September 30, 2004	1,884	$ 13,337

9. TRUST UNIT RIGHTS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan (the "Plan") to replace the stock option plan of the Company. A total of 5,800,000 trust unit rights are reserved for issue under the Plan. Trust unit rights are granted at the market price of the trust units at the time of the 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 has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future oil and natural gas prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements and is recognized in earning over the vesting period of the plan. Compensation expense for the unit rights for the nine months ended September 30, 2004 was $6.2 million (three months ended September 30, 2004 - $3.2 million).

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

	# of rights	Weighted average exercise price (1)
Balance December 31, 2003	2,855	$ 9.34
Granted	580	$ 11.63
Exercised	(26)	$ 9.04
Cancelled	(475)	$ 9.32
Balance September 30, 2004	2,934	$ 9.01

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

The adoption of the amendments related to accounting for unit-based compensation (note 3) also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. For the nine months ended September 30, 2003, compensation expense related to the stock options granted by the Company since January 1, 2003 was $0.52 million. Compensation expense for options granted during 2003 was based on the estimated fair value at the time of the grant, and the expense was recognized over the vesting period of the options.

Three Months and Nine Months Ended September 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

10. FINANCIAL DERIVATIVE CONTRACTS

At September 30, 2004, the Trust had financial derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2004	5,000 bbls/d	US$24.00 – $28.60	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.05	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.08	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.38	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.48	WTI
Price collar	Calendar 2004	2,000 bbls/d	US$24.00 – $30.55	WTI
Price collar	Calendar 2004	3,000 bbls/d	US$24.00 – $32.05	WTI
Price collar	Calendar 2005	3,000 bbls/d	US$35.00 – $42.40	WTI
Price collar	Calendar 2005	2,000 bbls/d	US$35.00 – $42.50	WTI
Price collar	Calendar 2005	1,000 bbls/d	US$35.00 – $42.70	WTI
Price collar	Calendar 2005	2,000 bbls/d	US$35.00 – $42.75	WTI

			Exchange Rate	
Foreign currency	Period	Amount	Floor	Cap
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3100	CAD/USD $1.3400
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3280	CAD/USD $1.3560
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3160	CAD/USD $1.3365
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3400	CAD/USD $1.3665

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

As discussed in note 3, at January 1, 2004, the fair value of all outstanding financial derivative contracts that are not considered accounting hedges was recorded on the consolidated balance sheet with an offsetting deferred credit. The deferred credit is recognized into income over the life of the associated contracts. Under the new 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. The net changes in the fair value of these financial derivative contracts are as follows:

January 1, 2004 mark-to-market value	$ 10,110
Change in fair value	39,988
September 30, 2004 mark-to-market value	$ 50,098

Three Months and Nine Months Ended September 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Interest paid	**$ 8,744**	$ 6,914	**$ 19,297**	$ 22,288
Income taxes paid	**$ 2,025**	$ 2,033	**$ 15,077**	$ 10,801

12. RECLASSIFICATION

Certain comparative figures have been reclassified to conform to the current period's presentation.

13. SUBSEQUENT EVENTS

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian Unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. Trust units purchased from treasury under the DRIP will be issued at a five percent discount from the weighted average closing price of the trust units on the Toronto Stock Exchange. The DRIP will be available starting with the November 2004 distribution.

On October 29, 2004, the Company signed an agreement to sell certain petroleum and natural gas properties for total cash consideration of $14 million. The sale is subject to certain conditions and is scheduled to close by the end of November 2004. Upon closing of this transaction, the Company intends to use the proceeds for debt reduction.

On November 1, 2004, the Company and its banking syndicate amended the credit agreement to increase the amount available under the credit facilities to an aggregate of $205 million.

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

Dale O. Shwed
President and CEO
Crew Energy Inc.

OFFICERS

Raymond T. Chan
President and CEO

Daniel G. Belot
Vice President, Finance and CFO

Randal J. Best
Vice President, Corporate Development

Ralph W. Gibson
Vice President, Marketing

Anthony W. Marino
Chief Operating Officer

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

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AUDITORS

Deloitte & Touche LLP

BANKERS

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

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
mmboe	million 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
ENERGY TRUST