BAYTEX
ENERGY TRUST

Q1

FIRST QUARTER REPORT
FOR THE THREE MONTHS ENDED MARCH 31, 2004

HIGHLIGHTS

Baytex Energy Trust is pleased to report its operating and financial results for the three months ended March 31, 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., comparative information is provided for the three months ended March 31, 2003. However, results of the current period may not be entirely comparable to the corresponding period of last year as certain assets were not transferred to the Trust on September 2, 2003 pursuant to the Plan of Arrangement effecting the reorganization.

Financial	Three Months Ended March 31		
($ thousands, except per unit amounts)	2004	2003 (unaudited)	% Change
Petroleum and natural gas sales	**96,146**	124,805	(23)
Cash flow from operations[1]	**38,689**	54,707	(29)
Per unit – basic	**0.60**	1.03	(42)
– diluted	**0.60**	1.01	(41)
Cash distributions declared	**27,704**	–	n/a
Per unit	**0.45**	–	n/a
Net income (loss)	**(4,296)**	32,104	n/a
Per unit – basic	**(0.07)**	0.60	n/a
– diluted	**(0.07)**	0.59	n/a
Exploration and development	**29,243**	61,212	(52)
Acquisitions – net of dispositions	**–**	(134,950)	n/a
Total capital expenditures	**29,243**	(73,738)	n/a
Long-term notes	**235,819**	304,145	(22)
Working capital deficiency (surplus)	**24,287**	(93,860)	n/a
Total net debt	**260,106**	210,285	24
Operating			
Daily production			
Light oil (bbls/d)	**2,058**	2,969	(31)
Heavy oil (bbls/d)	**23,322**	23,278	–
Total oil (bbls/d)	**25,380**	26,247	(3)
Natural gas (mmcf/d)	**56.0**	74.0	(24)
Oil equivalent (boe/d @ 6:1)	**34,709**	38,580	(10)
Average sales prices (before hedging)			
WTI oil (US$/bbl)	**35.15**	33.86	4
Edmonton par oil ($/bbl)	**45.59**	50.91	(10)
BTE light oil ($/bbl)	**43.50**	46.21	(6)
BTE heavy oil ($/bbl)	**26.29**	32.99	(20)
BTE total oil ($/bbl)	**27.70**	34.57	(20)
BTE natural gas ($/mcf)	**6.43**	7.17	(10)
BTE oil equivalent ($/boe)	**30.63**	37.39	(18)
Weighted average units (thousands)			
Basic	**64,761**	53,313	21
Diluted	**64,767**	54,434	19

(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 investment.

OPERATIONS REVIEW

Production for the first quarter of 2004 averaged 34,709 boe/d despite a prolonged period of extreme winter conditions which curtailed both heavy oil and natural gas production. The table below provides a comparison of first quarter 2004 production with the previous quarter and with the first quarter of 2003 (excluding production associated with the assets not transferred to the Trust pursuant to the reorganization and production associated with the properties in Ferrier, which were sold at the end of March 2003). This production performance was achieved entirely through internal property development as no material asset acquisitions have been made since the beginning of 2003.

Baytex executed a conservative yet successful winter capital program with expenditures totaling $29.2 million. During the first quarter of 2004, the Trust participated in the drilling of 47 (45.9 net) wells, resulting in 27 (26.6 net) oil wells, nine (8.8 net) gas wells, seven (6.5 net) stratigraphic test wells and four (4.0 net) dry holes. The program's overall success rate was 91.5 percent (91.3 percent net). In addition, 10 wells were drilled by other operators through farm-in arrangements on Baytex lands which resulted in one oil well, two gas wells, four cased wells and three dry holes. Baytex has retained various working and royalty interests in these farm-out wells.

The Trust plans to continue with an active capital program for the remainder of 2004, drilling between 30 and 40 wells each quarter. Production is targeted to be maintained at a fairly constant rate, although a moderate portion of second quarter production is traditionally interrupted for a period of four to six weeks by road bans associated with spring breakup.

FINANCIAL REVIEW

Cash flow from operations for the first quarter of 2004 was $38.7 million, an increase of 27 percent from the $30.4 million in the previous quarter and a decrease of 13 percent from the $44.7 million in the first quarter of 2003 (pro forma the effect of the reorganization). The table below provides a comparison of the economic factors contributing to the changes in cash flow of these periods.

Operations Review

	Q1/2004	Q4/2003	Q1/2003
Light oil (bbls/d)	**2,058**	1,982	1,877
Heavy oil (bbls/d)	**23,322**	24,400	23,061
Natural gas (mmcf/d)	**56.0**	58.9	53.5
Boe/d @ 6:1	**34,709**	36,195	33,849

Financial Review

	Q1/2004	Q4/2003	Q1/2003
WTI oil (US$/bbl)	**35.15**	31.18	33.86
LLB differential (% of WTI)	**30%**	35%	25%
NYMEX gas (US$/mmbtu)	**6.05**	4.81	5.51
US$/C$ exchange rate	**0.7588**	0.7600	0.6624

The long-term fixed differential supply agreement has largely reduced the impact of heavy oil differential volatility on Baytex's cash flow. However, the Trust's risk management program has also significantly affected Baytex's ability to participate in the upside of lofty commodity prices. During the first quarter of 2004, derivative contracts reduced cash flow by $9.4 million or $0.15 per unit. Details of these derivative contracts are contained in note 9 to the financial statements. Baytex currently has no derivative contracts on commodity prices and foreign exchange in place beyond the end of 2004. Given recent political and economic developments, Baytex will examine its risk management practice with the intention of retaining more upside in future commodity prices.

Cash costs for the current period were held at prior year levels, with operating expenses at $6.78 per boe, general and administrative expenses at $1.06 per boe, interest expense at $1.23 per boe and capital taxes at $0.69 per boe. These cost levels compare to $6.74, $1.07, $1.58 and $1.05, respectively, per boe for the fourth quarter of 2003. Baytex plans to maintain cash costs at the first quarter levels for the balance of this year.

Net earnings for the current period were significantly affected by a number of new accounting policies mandated by the Canadian Institute of Chartered Accountants and national securities regulators. These new policies are more fully described in note 3 to the financial statements. Amongst them, net earnings were most affected by the new policy on hedge accounting. Under this policy, derivative contracts that are not designated as effective hedges for accounting purposes are subject to fair value accounting which requires that changes in their fair value be recognized as income or expenses in each reporting period. Accordingly, a total loss of $16.8 million, including $2.5 million of amortization of deferred derivative loss, was recognized in the first quarter of 2004 but has no impact on cash flow for the reported period. As it is not possible to forecast commodity prices or foreign exchange volatilities, future earnings could be subject to significant fluctuations due to this new accounting requirement.

CASH DISTRIBUTIONS AND TRUST UNIT PERFORMANCE

Cash distributions declared during the first quarter of 2004 represent 72 percent of cash flow from operations. Baytex intends to maintain its $0.15 per unit monthly distribution for the remainder of 2004, assuming no material changes to current operating conditions and commodity prices. Baytex trust units have returned approximately 20 percent to its holders in the first four months of 2004, making it one of the best performing investments within the S&P/TSX Energy Trust Index. With its units still trading at one of the lowest cash flow multiples amongst its peers, Baytex hopes to continue to deliver superior returns to its investors.

On behalf of the Board of Directors,

[signed]

Raymond T. Chan, CA
President and Chief Executive Officer
May 11, 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") should be read in conjunction with 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, 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 and other assets and deferred credits. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

Production

Light oil production for the first quarter of 2004 decreased by 31 percent to 2,058 bbls/d from 2,969 bbls/d a year earlier. Heavy oil production was 23,322 bbls/d for the first quarter of 2004, consistent with 23,278 bbls/d a year ago. Natural gas production decreased by 24 percent to 56.0 mmcf/d from 74.0 mmcf/d for the same period last year. The decrease in light oil and natural gas production was the result of property dispositions that occurred at the end of the first quarter of 2003 and the transfer of petroleum and natural gas assets to Crew in September 2003.

Revenue

Petroleum and natural gas sales decreased 23 percent to $96.1 million for the first quarter of 2004 from $124.8 million for the first quarter of 2003.

For the sales unit calculations, heavy oil sales for the three months ended March 31, 2004 were 218 barrels per day lower than the production for the period due to

Revenue

	Three Months ended March 31			
		2004		2003
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue				
Light oil	**8,146**	**43.50**	12,346	46.21
Heavy oil	**55,269**	**26.29**	64,689	32.99
Realized loss on derivatives	**(9,422)**	**(4.11)**	(13,581)	(6.10)
Total oil revenue	**53,993**	**23.58**	63,454	28.48
Natural gas revenue	**32,731**	**6.43**	47,770	7.17
Total revenue (boe @ 6:1)	**86,724**	**27.63**	111,224	33.32

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

inventory in transit under the Frontier supply agreement. The corresponding number for the three months ended March 31, 2003 was 1,490 barrels per day.

Revenue from light oil for the first quarter of 2004 decreased 34 percent from the same period a year ago due to a 31 percent decrease in production and a six percent decrease in the wellhead price. Revenue from heavy oil decreased as wellhead prices decreased by 20 percent. Revenue from natural gas decreased 31 percent as the production decreased 24 percent and wellhead prices decreased by 10 percent.

Royalties

Total royalties decreased 31 percent to $15.3 million for the first quarter of 2004 from $22.2 million for the same period in 2003. The decrease is the result of lower production revenue for the period. Total royalties for the first quarter of 2004 were 15.9 percent of sales compared to 17.8 of sales for the same period in 2003. For the first quarter of 2004, royalties were 13.8 percent of sales for light oil, 12.9 percent for heavy oil and 21.5 percent for natural gas. These rates compared to 18.4 percent, 14.0 percent and 22.8 percent, respectively, for the same period in 2003.

Operating Expenses

Operating expenses for the first quarter of 2004 increased eight percent to $21.3 million from $19.7 million for the corresponding quarter last year. Operating expenses were $6.78 per boe for the first quarter of 2004 compared to $5.91 per boe for the first quarter of 2003. This increase is attributable to the disposition of properties with lower operating costs and a general increase in costs in field operations. For the first quarter of 2004, operating expenses were $8.35 per barrel of light oil, $7.51 per barrel of heavy oil and $0.77 per mcf of natural gas. The operating expenses for the same period a year ago were $4.40, $7.21 and $0.66, respectively.

Transportation Expenses

Transportation expenses for the first three months of 2004 were $4.9 million compared to $4.2 million in the prior period. These expenses were $1.56 per boe for the first quarter of 2004 compared to $1.25 per boe for the first quarter of 2003. Transportation expenses for the first quarter of 2004 were $1.73 per barrel of oil and $0.19 per mcf of natural gas. The corresponding amounts for 2003 were $1.43 and $0.15, respectively.

General and Administrative Expenses

General and administrative expenses for the first quarter of 2004 were $3.3 million compared to $1.6 million in 2003. On a per sales unit basis, these expenses were $1.06 per boe for the first three months of 2004 compared to $0.48 per boe in 2003. In accordance with the full-cost accounting policy, $1.6 million of expenses were capitalized in the first quarter of 2003, compared to no capitalized expenses for the first quarter of 2004. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Unit-based Compensation Expense

Compensation expense was $1.3 million for the first three months of 2004 compared to $0.3 million in the prior period. 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 were $3.9 million for the first quarter of 2004, down from $6.5 million in the same quarter last year. The decrease is due to the redemption during 2003 of the senior secured term notes and the impact of the stronger Canadian dollar on U.S. dollar-based interest expenses.

Foreign Exchange

The foreign exchange loss in the first quarter of 2004 was $3.2 million compared to a gain of $22.8 million in the same period a year ago. The loss is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7631 at March 31, 2004, compared to 0.7737 at December 31, 2003. The 2003 gain is based on translation of the long-term debt at 0.6806 at March 31, 2003, compared to 0.6331 at December 31, 2002.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion increased to $40.0 million for the first quarter of 2004 compared to $26.7 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was $12.75 per boe compared to $8.00 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.

Income Taxes

Current tax expenses were $2.2 million for the first quarter of 2004 compared to $2.6 million for the same quarter a year ago. The current tax expense is comprised of $1.4 million of Saskatchewan Capital Tax and $0.8 million of Large Corporation Tax compared to $2.2 million and $0.4 million, respectively, in the corresponding period in 2003.

The future tax recovery included the impact of the reduction in the Alberta corporate tax rate from 12.5 percent to 11.5 percent.

Net Income

The net loss for the first quarter of 2004 of $4.3 million was the result of increased charges for depletion, depreciation and accretion, the foreign exchange loss and the losses on financial derivatives. The net income for the first quarter of 2003 was impacted by the foreign exchange gain for that period.

Liquidity and Capital Resources

At March 31, 2004, total net debt (including working capital) was $260.1 million compared to $213.6 million at December 31, 2003. At March 31, 2004, there were no amounts outstanding under the bank credit facilities. The bank credit facilities at March 31, 2004 totalled $165.0 million.

Capital Expenditures

Exploration and development expenditures decreased to $29.2 million for the first quarter of 2004 compared to $61.2 million a year ago. The Trust's total capital expenditures are summarized as follows:

Capital Expenditures

	Three Months Ended March 31	
($ thousands)	2004	2003
Land	**1,434**	4,895
Seismic	**150**	2,829
Drilling and completion	**18,480**	42,780
Equipment	**8,844**	8,803
Other	**335**	1,905
Total exploration and development	**29,243**	61,212
Property acquisitions	**–**	54
Property dispositions	**–**	(135,004)
Net capital expenditures	**29,243**	(73,738)

(thousands) (unaudited)	**March 31, 2004**	December 31, 2003 *(restated – see note 3)*
Assets		
Current assets		
Cash and short-term investments	**$ 32,531**	$ 53,731
Accounts receivable	**43,185**	48,608
Financial derivative contracts *(note 9)*	**1,889**	–
Crude oil inventory	**7,081**	5,900
	84,686	108,239
Deferred derivative loss *(note 9)*	**7,583**	–
Deferred charges and other assets	**7,447**	7,764
Petroleum and natural gas properties	**853,650**	862,350
	$ 953,366	$ 978,353
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 73,285**	$ 80,126
Distributions payable to unitholders	**9,405**	9,123
Financial derivative contracts *(note 9)*	**26,283**	–
	108,973	89,249
Long-term debt *(note 4)*	**235,819**	232,562
Asset retirement obligations *(note 5)*	**57,398**	55,996
Future income taxes	**150,684**	169,336
	552,874	547,143
Unitholders' Equity		
Unitholders' capital *(note 7)*	**458,967**	446,594
Exchangeable shares *(note 7)*	**13,999**	26,372
Contributed surplus	**1,506**	224
Accumulated distributions	**(61,086)**	(33,382)
Accumulated deficit	**(12,894)**	(8,598)
	400,492	431,210
	$ 953,366	$ 978,353

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED DEFICIT

	Three Months Ended March 31	
(thousands, except per unit data) (unaudited)	2004	2003
		(restated – note 3)
Revenue		
Petroleum and natural gas sales	$ 96,146	$ 124,805
Royalties	(15,291)	(22,241)
Realized loss on financial derivatives	(9,422)	(13,581)
Unrealized loss on financial derivatives	(14,284)	–
	57,149	88,983
Expenses		
Operating	21,275	19,732
Transportation *(note 3)*	4,910	4,177
General and administrative	3,316	1,600
Unit-based compensation *(note 8)*	1,281	317
Interest *(note 4)*	3,872	6,457
Foreign exchange (gain) loss	3,257	(22,832)
Depletion, depreciation and accretion	40,024	26,703
	77,935	36,154
Income (loss) before income taxes	(20,786)	52,829
Income taxes (recovery)		
Current	2,162	2,570
Future	(18,652)	18,155
	(16,490)	20,725
Net income (loss)	(4,296)	32,104
Accumulated deficit, beginning of period, as reported previously	(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	$ (12,894)	$ (11,809)
Net income (loss) per trust unit		
Basic	$ (0.07)	$ 0.60
Diluted	$ (0.07)	$ 0.59

See accompanying notes to the consolidated financial statements.

	Three Months Ended March 31	
(thousands) (unaudited)	2004	2003
		(restated – note 3)
Cash provided by (used in):		
Operating Activities		
Net income (loss)	$ (4,296)	$ 32,104
Items not affecting cash:		
Unit-based compensation	1,281	317
Amortization of deferred charges	2,791	260
Foreign exchange (gain) loss	3,257	(22,832)
Depletion, depreciation and accretion	40,024	26,703
Unrealized loss on financial derivatives *(note 9)*	14,284	–
Future income taxes (recovery)	(18,652)	18,155
Cash flow from operations	38,689	54,707
Change in non-cash working capital	(4,141)	(22,922)
Site restoration and reclamation expenditures	(678)	(382)
(Increase) decrease in deferred charges and other assets	53	52
	33,923	31,455
Financing Activities		
Increase in deferred charges and other assets	–	(1,125)
Payments of distributions	(27,422)	–
Issue of common shares	–	2,668
	(27,422)	1,543
Investing Activities		
Petroleum and natural gas property expenditures	(29,243)	(61,266)
Disposal of petroleum and natural gas properties	–	135,004
Change in non-cash working capital	1,542	31,613
	(27,701)	105,351
Change in cash and short-term investments	(21,200)	138,349
Cash and short-term investments, beginning of period	53,731	4,098
Cash and short-term investments, end of period	$ 32,531	$ 142,447

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 as at and for the year ended December 31, 2003.

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 $0.32 million for the three months ended March 31, 2003 was recorded for all stock options granted by the Company since January 1, 2003, with a corresponding amount recorded as contributed surplus (see note 8).

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 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.

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 three months ended March 31, 2003 decreased by $0.52 million (net of future income tax of $0.39 million). At December 31, 2003, the asset retirement obligations balance increased by $32.5 million to $56.0 million, the petroleum and natural gas assets balance increased by $19.2 million to $862.3 million and the future tax liability decreased by $5.0 million to $169.3 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 5).

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 becomes 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 as 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 March 31, 2004, the Trust recorded a liability of $26.3 million and an asset of $1.9 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 March 31, 2004 has been recorded as an unrealized loss on non-hedging financial derivatives of $14.3 million in the consolidated statement of operations (note 9).

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 both increased by $4.9 million and $4.2 million in the first quarters of 2004 and 2003, respectively, as a result of this change. This change in classification had no impact on net income and the comparative figures have been reclassified to conform to the presentation adopted for the current period.

4. LONG-TERM DEBT

	March 31, 2004	December 31, 2003
10.5% senior subordinated notes (US$247)	$ 324	$ 319
9.625% senior subordinated notes (US$179,699)	235,495	232,243
	$ 235,819	$ 232,562

Interest Expense

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

	Three Months Ended March 31,	
	2004	2003
Credit facility charges	$ 140	$ 31
Amortization of deferred charges	263	260
Long-term debt	3,469	6,166
Total interest	$ 3,872	$ 6,457

5. ASSET RETIREMENT OBLIGATIONS

	Three Months Ended March 31,	
	2004	2003
Balance, beginning of period	$ 55,996	$ 52,244
Liabilities incurred	960	1,450
Liabilities settled	(678)	(382)
Accretion	1,120	962
Balance, end of period	$ 57,398	$ 54,274

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 March 31, 2004 is $118.9 million (March 31, 2003 – $120.4 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.

6. INCOME TAXES

Future income tax expense for the period ended March 31, 2004 included a non-recurring adjustment of $1.8 million to future income taxes resulting from a decrease to the Alberta corporate income tax rate from 12.5 percent to 11.5 percent.

7. 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	1,879	12,373
Balance March 31, 2004	62,700	$ 458,967

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 March 31, 2004 was 1.09003 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded.

Exchangeable Shares	# of shares	Amount
Balance December 31, 2003	3,725	$ 26,372
Exchanged for trust units	(1,748)	(12,373)
Balance March 31, 2004	1,977	$ 13,999

8. 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 trust unit 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 three months ended March 31, 2004 was $1.3 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	$ 9.71
Granted	175	$ 10.47
Cancelled	(166)	$ 9.79
Balance March 31, 2004	2,864	$ 9.83

(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 three months ended March 31, 2003, compensation expense related to the stock options granted by the Company since January 1, 2003 was $0.32 million. Compensation expense for options granted during 2003 was based on the estimated fair value at the time of the grant based on the Black-Scholes option-pricing model using the following assumption: risk-free interest rate of 4.5 percent; expected life of four years; and expected volatility of 54 percent. The expense was recognized over the vesting period of the options.

9. FINANCIAL DERIVATIVE CONTRACTS

At March 31, 2004, the Trust had financial derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2004	5,000 bbl/d	US$24.00 – $28.60	WTI
Price collar	Calendar 2004	1,500 bbl/d	US$24.00 – $29.05	WTI
Price collar	Calendar 2004	1,500 bbl/d	US$24.00 – $29.08	WTI
Price collar	Calendar 2004	1,000 bbl/d	US$24.00 – $29.38	WTI
Price collar	Calendar 2004	1,000 bbl/d	US$24.00 – $29.48	WTI
Price collar	Calendar 2004	2,000 bbl/d	US$24.00 – $30.55	WTI
Price collar	Calendar 2004	3,000 bbl/d	US$24.00 – $32.05	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$179,669,000	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 changes in the fair value of these hedges are as follows:

January 1, 2004 mark-to-market value	$ 10,110
Change in fair value	14,284
March 31, 2004 mark-to-market value	$ 24,394

10. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended March 31	
	2004	2003
Interest paid	**$ 10,498**	$ 13,939
Income taxes paid	**$ 4,854**	$ 6,686

11. RECLASSIFICATION

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

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

Richard W. Naden
Vice President, Engineering and Operations

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.

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ENERGY TRUST