BAYTEX

ENERGY TRUST

Baytex Energy Trust is pleased to report its operating and financial results for the period ended September 30, 2003. Baytex Energy Trust commenced operations as an oil and gas income trust on September 2, 2003. However, as the Trust is the successor organization to Baytex Energy Ltd., this interim report is provided for the three months and nine months ended September 30, 2003 and 2002. The operating results under the Trust in September are also provided for information purposes.

Highlights	Month ended September 30, 2003	Three months ended September 30 **2003**	2002	% Change	Nine months ended September 30 **2003**	2002	% Change
Financial	(unaudited)	(unaudited)			(unaudited)		
($ thousands, except per unit amounts)							
Petroleum and natural gas sales	26,649	**87,200**	94,633	(8)	**273,535**	265,270	3
Cash flow from operations(1)	11,392	**19,975**	48,637	(58)	**108,054**	137,970	(22)
Per unit – basic	0.20	**0.36**	0.93	(61)	**2.00**	2.65	(24)
– diluted	0.20	**0.36**	0.91	(60)	**2.00**	2.60	(23)
Cash flow from operations before reorganization costs(1)	11,392	**38,617**	48,637	(20)	**126,696**	137,970	(8)
Per unit – basic	0.20	**0.70**	0.93	(24)	**2.35**	2.65	(11)
– diluted	0.20	**0.70**	0.91	(22)	**2.35**	2.60	(10)
Net income (loss)		**(45,516)**	3,687	n/a	**29,257**	32,345	(10)
Per unit – basic		**(0.83)**	0.07	n/a	**0.54**	0.62	(13)
– diluted		**(0.83)**	0.07	n/a	**0.54**	0.61	(11)
Cash distribution per unit declared	0.15						
Exploration and development		**43,402**	29,567	47	**157,722**	101,837	55
Acquisitions – net		**35**	705	(95)	**(131,042)**	(42,615)	208
Total capital expenditures		**43,437**	30,272	43	**26,680**	59,222	(55)
Long-term notes					**242,999**	328,261	(26)
Working capital deficiency					**24,806**	15,697	58
Total net debt					**267,805**	343,958	(22)
Operating							
Daily production							
Light oil *(bbls/d)*	1,824	**1,989**	2,999	(34)	**2,371**	3,237	(27)
Heavy oil *(bbls/d)*	25,331	**25,123**	23,504	7	**23,746**	23,616	1
Total oil *(bbls/d)*	27,155	**27,112**	26,503	2	**26,117**	26,853	(3)
Natural gas *(mmcf/d)*	59.6	**61.8**	71.3	(13)	**64.4**	72.8	(12)
Oil equivalent *(boe/d @ 6:1)*	37,088	**37,412**	38,391	(3)	**36,851**	38,986	(5)
Average sales prices (before hedging)							
WTI oil *(US$/bbl)*	28.31	**30.20**	28.27	7	**30.99**	25.39	22
Edmonton par oil *($/bbl)*	37.45	**40.94**	44.02	(7)	**44.33**	39.31	13
BTE light oil *($/bbl)*	34.00	**34.43**	37.36	(8)	**39.79**	32.71	22
BTE heavy oil *($/bbl)*	21.75	**24.19**	31.03	(22)	**26.07**	26.50	(2)
BTE total oil *($/bbl)*	22.57	**24.92**	31.75	(21)	**27.35**	27.25	–
BTE natural gas *($/mcf)*	5.38	**5.62**	3.33	69	**6.28**	3.49	80
BTE oil equivalent *($/boe)*	25.18	**27.36**	28.10	(3)	**30.41**	25.28	20
Weighted average units *(thousands)*							
Basic	58,037	**55,094**	52,325	5	**54,023**	51,151	4
Diluted	58,040	**55,052**	53,278	3	**54,025**	53,043	2

(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.

Creation of the Trust As a result of the Plan of Arrangement approved at a special meeting of the shareholders of Baytex Energy Ltd. held on August 28, 2003, Baytex Energy Trust and Crew Energy Inc. were created effective September 2, 2003. For each common share of Baytex Energy Ltd., shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The units of Baytex Energy Trust and common shares of Crew Energy Inc. commenced trading on the Toronto Stock Exchange on September 8, 2003 as distinct and separate securities.

Business Strategy The business objective of Baytex as an income trust is to deliver acceptable cash returns to unitholders on a consistent basis. With the unique attributes of its assets and capital structure, Baytex is well positioned both from an operational and a financial point of view to achieve this objective.

Operationally, one of the main challenges for producers of conventional oil and gas is having to replace production declines. The conventional oil and gas income trust sector in Canada has traditionally relied on asset acquisitions for replacement purposes. The recent proliferation of income trusts has only added to the competitive nature of the acquisition market. Although Baytex will evaluate the applicable acquisition opportunities available in its operating core areas, its plan is to replace production and reserve declines mainly through internal property development. Baytex possesses a vast inventory of development projects in the west central Saskatchewan heavy oil region and in the Cold Lake, Ardmore and Seal areas in east central Alberta. The ability to generate replacement production organically will allow Baytex to better control the cost and timing of its capital investments.

Financially, Baytex's capital structure and management initiatives provide excellent stability and flexibility for the future operations of the Trust:

- only outstanding debt at September 30, 2003 was US$180 million of subordinated notes due 2010;
- banking facilities totalling $165 million were entirely undrawn as at quarter-end;
- U.S. dollar denominated debt reduces the negative impact of a stronger Canadian currency on the Trust's revenue stream;
- policy to retain 30 percent to 40 percent of cash flow to fund capital programs represents approximately twice the historical level retained by industry peers;
- a five-year supply agreement eliminates heavy oil differential volatility on approximately 75 percent of the Trust's heavy oil production after royalties;
- oil price exposure for 2004 protected by a 15,000 bbls/d WTI costless collar hedge between US$24.00 and US$29.75;
- natural gas price exposure for 2004 protected by 9.5 mmcf/d of physical sales contracts with prices collared between C$5.28 and C$8.57 per mcf during the winter months and C$4.75 and C$6.75 per mcf during the summer months;
- foreign exchange exposure for 2004 protected by a US$12 million per month costless dollar hedge between 0.7556 and 0.7409; and
- the 9.625 percent coupon on the US$180 million subordinated notes swapped for a current equivalent rate of 6.38 percent (three-month LIBOR plus 5.20 percent) until the maturity of the notes to take advantage of the prevailing interest rate environment.

These comprehensive measures will assist in maintaining the necessary financial strength critical to sustain the operations of the Trust.

Operations Review Oil and gas production under the pre-reorganized Baytex Energy Ltd. for the months of July and August 2003 averaged 37,569 boe/d, an increase of nine percent over the 34,574 boe/d for the second quarter of 2003. The reorganization saw approximately 1,500 boe/d of production transferred to Crew Energy Inc. at the end of August. Production for September 2003 under the Trust averaged 37,088 boe/d, representing an impressive gain of 15 percent over the average production of 32,250 boe/d for the first quarter of 2003, adjusted for the sale of Ferrier in March and the spin-off of properties to Crew. All of this production gain was from internal property development, evidencing the quality and potential of the assets of the Trust.

Baytex continued with an active capital program in the third quarter of 2003. During this period, Baytex participated in the drilling of 62 (58.1 net) wells, resulting in 29 (27.0 net) oil wells, 26 (24.6 net) gas wells and seven (6.5 net) dry holes. The program's overall success rate was 88.7 percent (88.8 percent net). Included in these figures was the Trust's drilling program for the month of September 2003, when it participated in the drilling of 26 (24.0 net) wells, resulting in 10 (9.2 net) oil wells, 15 (13.8 net) gas wells and one (1.0 net) dry hole. The overall success rate in September was 96.2 percent (95.9 percent net).

Outlook Baytex plans to incur capital expenditures between $20 to $25 million in the fourth quarter of 2003 and another $35 to $40 million in the first quarter of 2004. Capital spending during this period is normally higher than the rest of the year as the Trust has the opportunity to develop its winter access only conventional oil and gas properties in the northern areas as well as its heavy oil assets in the Seal area. Baytex plans to spend approximately $100 million of capital during calendar 2004.

Baytex's inaugural monthly distribution of $0.15 per trust unit was paid on October 15, 2003. Total cash payment was $8.0 million, representing 70 percent of the $11.4 million of cash flow for September. Its second monthly distribution of $0.15 per unit is scheduled to be paid on November 17, 2003. The Trust plans to maintain this level of distribution for all of its fourth quarter operations provided that there are no significant changes to commodity prices. Given similar prices, Baytex should enjoy an improvement in cash flow in 2004 as the current punitive oil hedges expire at the end of 2003. Oil price hedges currently in place are reducing revenue by approximately $2 million per month until year-end with the 2004 hedges done at substantially improved levels. The interest rate swap just completed in November will also reduce financing charges by approximately $7.6 million annually under current rates.

The Alberta Securities Commission is implementing new disclosure standards relating to the reporting of oil and gas reserves (National Instrument 51-101) for companies reporting year-ends beginning with December 31, 2003. As Baytex embarks on a new era under its new corporate structure, its Board of Directors has engaged Sproule Associates Limited as the independent reserve evaluators for all of the Trust's oil and gas properties. Sproule is one of Canada's leading independent reservoir engineering firms and is particularly experienced in the evaluation of Western Canadian heavy oil properties. Their appointment will ensure the compliance of Baytex under the requirements of NI 51-101. The directors and management of Baytex are committed to the practice of proper disclosure and corporate governance in all aspects of the operations of the Trust.

Baytex has a 10-year history of successful oil and gas operations in the Western Canadian Sedimentary Basin. As a newly formed energy trust, Baytex embarks on a new era of providing superior returns to its investors. I would like to take this opportunity to thank all of the management, staff and directors of Baytex who worked so tirelessly on the successful conversion of Baytex to an energy income trust.

On behalf of the Board of Directors

Raymond T. Chan
President and Chief Executive Officer

November 13, 2003

Reorganization Under Plan of Arrangement The corporate reorganization, as described in the Plan of Arrangement dated July 25, 2003, became effective on September 2, 2003. Under the reorganization, Baytex Energy Ltd. transferred to Crew Energy Inc. ("Crew") a portion of its producing and exploratory oil and natural gas assets. For each common share of Baytex Energy Ltd., shareholders received either one unit of Baytex Energy Trust (the "Trust") and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. Baytex Energy Ltd. (the "Company") is a wholly owned 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 Baytex Energy Ltd.

Management's discussion and analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the three months and nine months ended September 30, 2003 and the audited consolidated financial statements and MD&A for the year ended December 31, 2002. Per 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, deferred charges 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.

For the per barrel calculations, heavy oil sales for the three months ended September 30, 2003 were 24 barrels per day lower than the production for the period due to inventory in transit under the Frontier supply agreement. The corresponding number for the nine months ended September 30, 2003 was 665 barrels per day.

Production Light oil production for the third quarter of 2003 decreased by 34 percent to 1,989 bbs/d from 2,999 bbls/d a year earlier due to the sale of properties in March 2003 in the Ferrier area. Heavy oil production increased by seven percent to 25,099 bbls/d for the third quarter of 2003 from 23,504 bbls/d a year ago. This increase was due to the acquisition of assets in Ardmore in October 2002. Natural gas production decreased by 13 percent to 61.8 mmcf/d compared to 71.3 mmcf/d for the same period last year due to the sale of the Ferrier properties and the transfer of properties to Crew Energy Inc. in September 2003.

For the first nine months of 2003, light oil production decreased by 27 percent to 2,371 bbls/d from 3,237 bbls/d for the same period last year. Heavy oil production increased two percent to 23,081 bbls/d for the first nine months of 2003 from 23,616 bbls/d for the same period in 2002. Natural gas production decreased by 12 percent to average 64.4 mmcf/d for the first nine months of 2003 compared to 72.8 mmcf/d for 2002. These production changes were due to the same factors as noted for the third quarter comparisons.

Revenue Petroleum and natural gas sales decreased eight percent to $87.2 million for the third quarter of 2003 from $94.6 million for the third quarter of 2002. For the first nine months, petroleum and natural gas sales increased by three percent to $273.5 million in 2003 from $265.3 million a year earlier.

	Three months ended September 30			
	2003		2002	
	($ thousands)	*($/Unit)*	*($ thousands)*	*($/Unit)*
Oil revenue *(barrels)*				
Light oil	**6,302**	**34.43**	10,307	37.36
Heavy oil	**55,861**	**24.19**	67,105	31.03
Derivative contracts loss	**(6,899)**	**(2.77)**	(6,704)	(2.75)
Total oil revenue	**55,264**	**22.17**	70,708	29.00
Natural gas revenue *(mcf)*	**31,936**	**5.62**	21,850	3.33
Derivative contracts gain	**–**	**–**	2,075	0.32
Total natural gas revenue	**31,936**	**5.62**	23,925	3.65
Total revenue *(boe @ 6:1)*	**87,200**	**25.36**	94,633	26.79

Revenue from light oil for the third quarter of 2003 decreased 39 percent from the same period a year ago due to a 34 percent decrease in production and an eight percent decrease in wellhead price. Revenue from heavy oil decreased 17 percent as wellhead price decreased by 22 percent, which offset the seven percent increase in production. Revenue from natural gas increased 46 percent as the 69 percent increase in wellhead price was offset by a 13 percent decrease in production.

	Nine months ended September 30			
	2003		2002	
	($ thousands)	*($/Unit)*	*($ thousands)*	*($/Unit)*
Oil revenue *(barrels)*				
Light oil	**25,757**	**39.79**	28,907	32.71
Heavy oil	**164,258**	**26.07**	170,844	26.50
Derivative contracts loss	**(26,860)**	**(3.87)**	(6,576)	(0.90)
Total oil revenue	**163,155**	**23.48**	193,175	26.35
Natural gas revenue *(mcf)*	**110,380**	**6.28**	69,300	3.49
Derivative contracts gain	**–**	**–**	2,795	0.14
Total natural gas revenue	**110,380**	**6.28**	72,095	3.63
Total revenue *(boe @ 6:1)*	**273,535**	**27.69**	265,270	24.92

For the first nine months of 2003, light oil revenue decreased 11 percent from the same period last year due to a 22 percent increase in wellhead price offsetting a 27 percent decrease in production. Revenue from heavy oil decreased four percent due to a two percent decrease in wellhead price and a two percent decrease in production. Revenue from natural gas increased 59 percent as wellhead price increased 80 percent and production decreased 12 percent compared to 2002.

Royalties Total royalties decreased eight percent to $15.3 million for the third quarter of 2003 from $16.6 million for the same period last year. The decrease is the result of lower production revenue for 2003. Total royalties for the third quarter of 2003 were 16.2 percent of sales compared to 16.8 percent of sales for the same period in 2002. For the third quarter of 2003, royalties were 17.3 percent of sales for light oil, 13.7 percent for heavy oil and 20.3 percent for natural gas. These rates compared to 15.7 percent, 15.4 percent and 21.3 percent, respectively, for the same period last year.

For the nine months ended September 30, 2003, royalties increased 27 percent to $53.7 million from $42.3 million for the same period last year and were 17.9 percent of sales compared to 15.7 percent of sales in 2002. Royalties for the first nine months of 2003 were 18.6 percent of sales for light oil, 14.4 percent for heavy oil and 22.9 percent for natural gas. These rates compared to 16.1 percent, 14.2 percent and 19.5 percent, respectively, for the same period in 2002.

Operating Expenses Operating expenses for the third quarter of 2003 increased 19 percent to $22.2 million from $18.6 million for the corresponding quarter last year. Operating expenses were $6.75 per boe for the third quarter of 2003 compared to $5.14 per boe for the third quarter of 2002. This increase is attributable to the disposition of properties with lower operating costs and a general increase in costs in field operations. For the third quarter of 2003, operating expenses were $11.31 per barrel of light oil, $7.10 per barrel of heavy oil and $0.84 per mcf of natural gas. The operating expenses for the same period a year ago were $5.84, $6.00 and $0.61, respectively.

Operating expenses for the first nine months of 2003 increased 15 percent to $64.0 million from $55.4 million for 2002. This increase is primarily due to the same factors as noted in the third quarter comparison. Operating expenses were $6.48 per boe for the first nine months of 2003 compared to $5.21 per boe for the corresponding period of the prior year. For the first nine months of 2003, operating expenses were $7.73 per barrel of light oil, $7.31 per barrel of heavy oil and $0.73 per mcf of natural gas versus $6.13, $5.87 and $0.60, respectively, for the same period a year earlier.

General and Administrative Expenses General and administrative expenses for the third quarter of 2003 were $1.9 million compared to $1.7 million in 2002. On a boe basis, these expenses increased to $0.58 per boe from $0.49 per boe. In accordance with our full cost accounting policy, $1.0 million of expenses were capitalized for the months of July and August of 2003 compared to $1.7 million in the third quarter last year. As Baytex was reorganized in September 2003, no general and administrative expenses will be capitalized in the future from the inception of operations as an income trust.

General and administrative expenses for the first nine months of 2003 were $5.4 million, also consistent with the prior year. On a boe basis, these expenses increased from $0.48 per boe to $0.54 per boe. In accordance with our full cost accounting policy, $4.4 million of expenses were capitalized in the first eight months of 2003, compared with $5.1 million capitalized in the first nine months a year ago.

Interest Expenses Interest expenses on long-term notes and bank debt were $6.6 million for the third quarter of 2003, consistent with the same quarter last year. For the first nine months of 2003, interest expenses on long-term debt was $18.4 million compared to $18.0 million for the same period last year.

Cost on Exchange of Notes On July 9, 2003, the Company completed an exchange offer related to its outstanding US$150 million of 10.5 percent senior subordinated notes due 2011. The Company issued US$179.7 million ($247.1 million) of 9.625 percent senior subordinated notes due 2010 in exchange for US$149.8 million of the old notes and incurred a non-recurring, non-cash expense of $40.0 million on the completion of this transaction, which was recognized in the statement of operations.

The costs for the nine months ended September 30, 2003 includes the cost of $4.7 million recognized in May 2003 on the redemption of the US$57 million senior secured notes.

Foreign Exchange The foreign exchange gain in the third quarter of 2003 was $1.5 million compared to a loss of $13.9 million in the prior year. The gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7405 at September 30, 2003 compared to 0.7378 at June 30, 2003. The 2002 loss is based on translation at 0.6306 at September 30, 2002 compared to 0.6585 at June 30, 2002.

The foreign exchange gain for the first nine months of 2003 was $41.7 million compared to $1.4 million in the prior year. The 2003 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7405 at September 30, 2003 compared to 0.6331 at December 31, 2002. The 2002 gain is based on translation at 0.6306 at September 30, 2002 compared to 0.6279 at December 31, 2001.

Depletion and Depreciation The provision for depletion and depreciation increased to $27.1 million for the third quarter of 2003 compared to $26.7 million for the same quarter a year ago. On a boe basis, the provision for the current quarter was $7.88 per boe compared to $7.55 per boe for the same quarter in 2002.

Depletion and depreciation decreased to $75.9 million for the first nine months of 2003 compared to $79.7 million for the same period last year. On a boe basis, the provision for the current period was $7.68 per boe compared to $7.49 per boe for the same period a year earlier.

Site Restoration The current quarter provision for site restoration was $0.5 million compared to $0.7 million for same quarter last year. On a boe basis, the provision for the third quarter of 2003 was $0.13 per boe compared to $0.19 per boe for the corresponding quarter of last year.

Site restoration costs for the nine months ended September 30, 2003 decreased to $1.6 million from $2.1 million for the same period last year. On a boe basis, the provision for the first nine months of 2003 was $0.16 per boe compared to $0.20 per boe for the corresponding period of 2002.

Income Taxes Current tax expenses were $1.8 million for the third quarter of 2003 compared to $2.7 million for the same quarter a year ago. The decrease is due to a 1.6 percent reduction in the Saskatchewan Resource Surcharge rate on revenue from wells drilled after October 2002. The current tax expense is comprised of $1.5 million of Saskatchewan Capital Tax and $0.2 million of Large Corporation Tax compared to $2.3 million and $0.4 million, respectively, in the corresponding period in 2002.

Current tax expenses were $6.2 million for the first nine months of 2003 compared to $7.3 million for the same period last year. The current tax expense is comprised of $5.3 million of Saskatchewan Capital Tax and $0.9 million of Large Corporation Tax compared to $6.1 million and $1.2 million, respectively, in 2002.

Net Income (Loss) The loss for the third quarter of 2003 is the result of the costs on the exchange of the senior subordinated notes, the adjustments to future income taxes as a result of the reorganization and the reorganization costs of $18.6 million.

Net income for the first nine months of 2003 decreased to $29.3 million from $32.3 million in the corresponding period of 2002 for the same reasons as noted in the third quarter comparison.

Liquidity and Capital Resources At September 30, 2003, total net debt (including working capital) was $267.8 million compared to $344.0 million at September 30, 2002 and $362.8 million at December 31, 2002. The decrease in total debt at the end of the third quarter of 2003 compared to 2002 was the result of proceeds from assets sales at the end of March 2003.

On September 3, 2003, the Company entered into a credit agreement with a new syndicate of chartered banks. The credit facilities aggregating $165.0 million are subject to semi-annual review beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At September 30, 2003, there were no amounts outstanding under the credit agreement.

Capital Expenditures Exploration and development expenditures increased to $157.7 million for the first nine months of 2003 compared to $101.8 million for the same period last year. The Company's total capital expenditures for these periods are summarized as follows:

	Nine months ended September 30	
($ thousands)	**2003**	2002
Land	**12,583**	9,955
Seismic	**6,941**	5,933
Drilling and completions	**96,825**	62,416
Equipment	**35,174**	17,441
Other	**6,199**	6,092
Total exploration and development	**157,722**	101,837
Property acquisitions	**6,233**	11,813
Property dispositions	**(137,275)**	(54,428)
Net capital expenditures	**26,680**	59,222

Consolidated Balance Sheets

(Unaudited) *(thousands)*	**September 30, 2003**	December 31, 2002
Assets		
Current assets		
Cash and short-term investments	**$ 23,207**	$ 4,098
Accounts receivable	**40,758**	52,667
Crude oil inventory *(note 4)*	**3,511**	–
	67,476	56,765
Deferred charges and other assets	**8,055**	8,679
Petroleum and natural gas properties *(note 3)*	**861,237**	932,316
	$ 936,768	$ 997,760
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 84,244**	$ 92,563
Distributions payable to unitholders	**8,038**	–
	92,282	92,563
Long-term debt *(note 5)*	**242,999**	326,977
Deferred credits	**–**	12,181
Provision for future site restoration costs	**22,393**	21,950
Future income taxes *(note 7)*	**185,438**	184,402
	543,112	638,073
Unitholders' Equity		
Unitholders' capital *(note 8)*	**379,417**	398,176
Exchangeable shares *(note 8)*	**31,509**	–
Accumulated distributions	**(8,038)**	–
Accumulated deficit	**(9,232)**	(38,489)
	393,656	359,687
	$ 936,768	$ 997,760

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Operations and Accumulated Deficit

(Unaudited) *(thousands, except per unit data)*	Three months ended September 30 2003	2002	Nine months ended September 30 2003	2002
Revenue				
Petroleum and natural gas	**$ 87,200**	$ 94,633	**$ 273,535**	$ 265,270
Royalties	**(15,253)**	(16,634)	**(53,677)**	(42,270)
	71,947	77,999	**219,858**	223,000
Expenses				
Operating	**23,233**	18,610	**63,968**	55,424
General and administrative	**1,993**	1,718	**5,357**	5,124
Interest *(note 5)*	**6,588**	6,591	**18,375**	17,999
Costs on exchange of notes *(note 5)*	**40,003**	–	**44,771**	–
Foreign exchange (gain) loss	**(1,469)**	13,889	**(41,664)**	(1,408)
Depletion and depreciation	**27,103**	26,668	**75,894**	79,697
Site restoration	**461**	674	**1,624**	2,102
Reorganization costs *(note 3)*	**18,642**	–	**18,642**	–
	116,554	68,150	**186,967**	158,938
Income (loss) before income taxes	**(44,607)**	9,849	**32,891**	64,062
Income taxes				
Current expense	**1,757**	2,720	**6,213**	7,270
Future expense (recovery) *(note 7)*	**(848)**	3,442	**(2,579)**	24,447
	909	6,162	**3,634**	31,717
Net income (loss)	**$ (45,516)**	$ 3,687	**29,257**	32,345
Accumulated deficit, beginning of period			**(38,489)**	(75,954)
Accounting policy change for foreign exchange			**–**	(7,671)
Accumulated deficit, beginning of period, as restated			**(38,489)**	(83,625)
Accumulated deficit, end of period			**$ (9,232)**	$ (51,280)
Net income (loss) per trust unit				
Basic	**$ (0.83)**	$ 0.07	**$ 0.54**	$ 0.62
Diluted	**$ (0.83)**	$ 0.07	**$ 0.54**	$ 0.61

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Unaudited) *(thousands)*	Three months ended September 30 **2003**	2002	Nine months ended September 30 **2003**	2002
Cash provided by (used in):				
Operating activities				
Net income (loss)	**$ (45,516)**	$ 3,687	**$ 29,257**	$ 32,345
Items not affecting cash:				
Site restoration	**461**	674	**1,624**	2,102
Amortization of deferred charges	**241**	277	**751**	787
Foreign exchange (gain) loss	**(1,469)**	13,889	**(41,664)**	(1,408)
Costs on exchange of notes *(note 5)*	**40,003**	–	**44,771**	–
Depletion and depreciation	**27,103**	26,668	**75,894**	79,697
Future income tax (recovery)	**(848)**	3,442	**(2,579)**	24,447
Cash flow from operations	**19,975**	48,637	**108,054**	137,970
Change in non-cash working capital	**10,920**	3,190	**(2,964)**	(13,128)
Decrease in deferred credits	**476**	(4,712)	**–**	(13,982)
Increase in deferred charges and other assets	**–**	13,306	**–**	13,306
	31,371	60,421	**105,090**	124,166
Financing activities				
Redemption of senior secured term notes	**–**	–	**(89,950)**	–
Decrease in bank loan	**–**	(10,282)	**–**	(76,253)
Increase in deferred charges and other assets	**(7,305)**	–	**(9,442)**	–
Repurchase of common shares	**–**	(55)	**–**	(55)
Issue of shares	**33,154**	1,851	**37,050**	2,573
	25,849	(8,486)	**(62,342)**	(73,735)
Investing activities				
Petroleum and natural gas property expenditures	**(43,203)**	(30,144)	**(163,955)**	(113,650)
Disposal of petroleum and natural gas properties	**(35)**	(128)	**137,275**	54,428
Properties held for sale	**–**	–	**–**	(46,895)
Change in non-cash working capital	**(10,211)**	(10,226)	**3,041**	67,123
	(53,449)	(40,498)	**(23,639)**	(38,994)
Change in cash and short-term investments	**3,771**	11,437	**19,109**	11,437
Cash and short-term investments, beginning of period	**19,436**	–	**4,098**	–
Cash and short-term investments, end of period	**$ 23,207**	$ 11,437	**$ 23,207**	$ 11,437

See accompanying notes to the consolidated financial statements.

Three months and nine months ended September 30, 2003 and 2002 (Unaudited) *(all tabular amounts in thousands, except per unit amounts)*

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"). Under the Plan of Arrangement, Baytex Energy Ltd. transferred to Crew a portion of its producing and exploratory oil and natural gas assets. For each common share of Baytex Energy Ltd., shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. Baytex Energy Ltd. is a wholly owned 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 Baytex Energy Ltd. 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 Company as at December 31, 2002. The interim consolidated financial statements contain disclosures, which are supplemental to the Company'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 Company's consolidated financial statements and notes thereto for the year ended December 31, 2002.

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level. The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes.

3. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement, the Company transferred to Crew Energy Inc. a portion of the Company's producing and exploratory oil and natural gas assets. As this was a related-party transaction, assets and liabilities were transferred at book value.

Oil and natural gas assets and equipment	$	21,244
Future income tax asset		3,278
Total assets transferred		24,522
Provision for future site restoration		559
Net assets transferred and reduction in share capital	$	23,963

The Company has recorded as an expense reorganization costs of $18.6 million associated with the Plan of Arrangement.

4. CRUDE OIL INVENTORY

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

5. LONG-TERM DEBT

	September 30, 2003	December 31, 2002
Senior secured term notes (US$57,000,000)	**$ –**	$ 90,037
10.5% senior subordinated term notes (September 30, 2003 – US$247,000; December 31, 2002 – US$150,000,000)	**334**	236,940
9.625% senior subordinated term notes (US$179,669,000)	**242,665**	–
	$ 242,999	$ 326,977

In May 2003, the Company redeemed the outstanding senior secured term notes for a total cash payment of $90 million, resulting in a cost of $4.7 million on the redemption.

On July 9, 2003, the Company completed an exchange offer related to its outstanding US$150 million of 10.5% senior subordinated notes due 2011 (the "Old Notes"). The Company issued US$179.7 million of 9.625% senior subordinated notes due 2010 in exchange for US$149.8 million of the Old Notes and incurred a non-recurring, non-cash expense of $40.0 million on the completion of this transaction, which was recognized in the statement of operations.

Interest Expense

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

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Bank loan	**$ 561**	$ 125	**$ 561**	$ 531
Amortization of deferred charge	**241**	277	**751**	787
Long-term debt	**5,786**	6,189	**17,063**	16,681
Total interest	**$ 6,588**	$ 6,591	**$ 18,375**	$ 17,999

6. BANK CREDIT FACILITIES

On September 3, 2003, the Company entered into a credit agreement with a new syndicate of chartered banks. The credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $165 million are subject to semi-annual review beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At September 30, 2003, there were no amounts outstanding under the bank credit facilities.

7. INCOME TAXES

Income tax expense for the periods ended September 30, 2003 include a non-recurring adjustment to future income taxes resulting from the corporate reorganization, including the dissolution of the partnership.

8. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Pursuant to the Plan of Arrangement, 53,304,858 trust units and 4,732,326 exchangeable shares were issued on the exchange of the common shares of Baytex Energy Ltd. The exchangeable shares are convertible into trust units based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. The exchange ratio at September 30, 2003 was 1.00000.

Trust Units	# of units	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	53,305	$ 377,419
Issued on conversion of exchangeable shares	282	1,998
Balance, September 30, 2003	53,587	$ 379,417

Exchangeable Shares	# of shares	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	4,732	$ 33,507
Exchanged for trust units	(282)	(1,998)
Balance, September 30, 2003	4,450	$ 31,509

Under the Plan of Arrangement, shareholders of Baytex Energy Ltd. received one unit in Baytex Energy Trust or one exchangeable share and one-third of a common share in Crew Energy Inc. for each common share held.

Common shares of Baytex Energy Ltd.	# of shares	Amount
Balance, December 31, 2002	52,819	$ 398,176
Flow-through shares issued	103	810
Future tax related to flow-through shares	–	(336)
Exercise of stock options	5,115	36,239
Transfer of assets under Plan of Arrangement	–	(23,963)
Balance, September 2, 2003 prior to Plan of Arrangement	58,037	410,926
Trust units issued	(53,305)	(377,419)
Exchangeable shares issued	(4,732)	(33,507)
Balance, September 30, 2003	–	$ –

9. TRUST UNIT RIGHTS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. The rights vest over three years and have a term of five years. At September 30, 2003, 5.8 million trust units are reserved under the Trust Unit Rights Incentive Plan for issuance.

The Trust Unit Rights Incentive Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain conditions. 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. Compensation expense for the three months and nine months ended September 30, 2003 was $7,000.

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

	# of rights	Weighted average exercise price
Initial grant September 9, 2003	2,593	$ 10.80
Granted	361	$ 10.04
Balance, September 30, 2003	2,954	$ 10.58

The outstanding stock options of Baytex Energy Ltd. were exercised or cancelled as follows:

	# of options	Weighted average exercise price
Balance, December 31, 2002	5,126	$ 6.98
Granted	121	$ 9.28
Exercised	(5,115)	$ 7.07
Cancelled	(132)	$ 5.44
Balance, September 30, 2003	–	–

Baytex Energy Ltd. accounted for its stock options using intrinsic values. On this basis, compensation costs were not required to be recognized in the financial statements for stock options granted at market value. Had compensation costs for the stock option plan been determined based on the fair-value method at the dates of grants under the plan after January 1, 2002, pro forma net income would be as follows:

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Net income (loss) as reported	**$ (45,516)**	$ 3,687	**$ 29,257**	$ 32,345
Fair value of stock options	**(1,089)**	(60)	**(1,089)**	(101)
Pro forma	**$ (46,605)**	$ 3,627	**$ 28,168**	$ 32,244
Net income (loss) per unit				
Basic as reported	**$ (0.83)**	$ 0.07	**$ 0.54**	$ 0.62
Pro forma	**$ (0.85)**	$ 0.07	**$ 0.52**	$ 0.62
Diluted as reported	**$ (0.83)**	$ 0.07	**$ 0.54**	$ 0.61
Pro forma	**$ (0.85)**	$ 0.07	**$ 0.52**	$ 0.61

The weighted average fair market value of options granted during the nine months ended September 30, 2003 was $4.21 per option (2002 – $2.62 per option). The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk-free interest rate of 4%; expected life of 4 years; and expected volatility of 52%.

10. DERIVATIVE CONTRACTS

The Company has entered into the following derivative contracts for risk management purposes:

Crude Oil – a total of 15,000 bbls/d of WTI costless collar contracts with a floor price of US$24.00 per barrel and a weighted average ceiling price of US$29.75 per barrel for calendar 2004.

Natural Gas – a total of 9.5 mmcf/d of physical sales contracts with prices collared between weighted averages of C$5.28 and C$8.57 per mcf during the winter months (November 2003 to March 2004) and C$4.75 and C$6.75 per mcf during the summer months (April to October 2004).

Foreign Exchange – a total of US$12.0 million per month of costless collar contracts to exchange into Canadian dollars between a weighted average floor rate of $0.7556 and a weighted average ceiling rate of $0.7409 for calendar 2004.

Interest Rate – the 9.625% coupon on the US$180 million senior subordinated notes swapped for floating rate equal to 3-month LIBOR plus 5.20% for the full term of the notes.

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Interest paid	**$ 6,914**	$ 9,853	**$ 22,288**	$ 23,634
Income taxes paid (refunded)	**$ 2,033**	$ (4,237)	**$ 10,801**	$ (3,986)

12. COMPARATIVE FIGURES

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

Corporate Information

Board of Directors

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W.A. Blake Cassidy
Retired Banker

Raymond T. Chan
President and CEO
Baytex Energy Trust

Edward Chwyl
Independent Businessman

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 and debt levels. 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 Company's areas of operations; and other factors, many of which are beyond the control of the Company. 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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