FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – MARCH 10, 2004

BAYTEX ENERGY TRUST ANNOUNCES FISCAL 2003 RESULTS

Baytex Energy Trust (TSX-BTE.UN) of Calgary, Alberta is pleased to report its operating and financial results for the periods ended December 31, 2003. Baytex Energy Trust commenced operations as an oil and gas income trust on September 2, 2003. The three months ended December 31, 2003 represent the Trust's first full quarter of operations. As the Trust is the successor organization to Baytex Energy Ltd., information herein is provided for the three months and years ended December 31, 2003 and 2002. Accordingly, results of the current periods may not be entirely comparable to the corresponding periods of last year as certain assets were transferred out of Baytex pursuant to the Plan of Arrangement effective September 2, 2003.

	Three Months Ended December 31			Year Ended December 31		
	2003	2002	% Change	**2003**	2002	% Change
FINANCIAL						
($ thousands, except per unit amounts)						
Petroleum and natural gas sales	77,869	100,590	(23)	351,404	365,860	(4)
Cash flow from operations (1)	30,179	53,116	(43)	138,233	191,086	(28)
Per unit - basic	0.51	1.00	(49)	2.49	3.65	(32)
- diluted	0.51	0.99	(49)	2.45	3.59	(32)
Cash flow from operations before reorganization costs (1)	30,388	53,116	(43)	157,084	191,086	(18)
Per unit - basic	0.51	1.00	(49)	2.83	3.65	(22)
- diluted	0.51	0.99	(49)	2.78	3.59	(23)
Cash distributions declared	25,344	-	n/a	33,382	-	n/a
Per unit	0.45	-	n/a	0.60	-	n/a
Net income	8,881	12,791	(31)	38,138	45,136	(16)
Per unit - basic	0.15	0.24	(38)	0.69	0.86	(20)
- diluted	0.15	0.24	(38)	0.67	0.85	(21)
Exploration and development	22,390	34,498	(35)	180,112	136,335	32
Acquisitions – net of dispositions	193	32,748	(99)	(130,849)	(9,867)	1,226
Total capital expenditures	22,583	67,246	(66)	49,263	126,468	(61)
Long-term notes				232,562	326,977	(29)
Working capital (surplus) deficiency				(18,990)	35,798	n/a
Total net debt				213,572	362,775	(41)
OPERATING						
Daily production						
Light oil (bbls/d)	1,982	2,909	(32)	2,273	3,154	(28)
Heavy oil (bbls/d)	24,400	25,009	(2)	23,911	23,967	-
Total oil (bbls/d)	26,382	27,918	(6)	26,184	27,121	(3)
Natural gas (mmcf/d)	58.9	71.8	(18)	63.0	72.6	(13)
Oil equivalent (boe/d @ 6:1)	36,195	39,890	(9)	36,686	39,214	(6)

	Three Months Ended December 31			Year Ended December 31		
	2003	2002	% Change	**2003**	2002	% Change
Average sales prices (before hedging)						
WTI oil (US$/bbl)	31.18	28.15	11	31.04	26.08	19
Edmonton par oil ($/bbl)	39.56	42.81	(8)	43.14	39.90	8
BTE light oil ($/bbl)	36.41	37.67	(3)	39.04	33.86	15
BTE heavy oil ($/bbl)	22.40	26.09	(14)	25.12	26.39	(5)
BTE total oil ($/bbl)	23.48	27.30	(14)	26.36	27.26	(3)
BTE natural gas ($/mcf)	5.37	5.29	2	6.07	3.94	54
BTE oil equivalent ($/boe)	25.90	28.64	(10)	29.28	26.14	12
Weighted average units (thousands)						
Basic	59,622	52,735	13	55,530	52,298	6
Diluted	59,644	53,695	11	56,520	53,237	6

(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.

2003 Corporate Highlights

- Completed a Plan of Arrangement transaction to establish Baytex Energy Trust and Crew Energy Inc. in September.
- Provided a 50% total return on investment during 2003 to the former shareholders of Baytex Energy Ltd.
- Executed a highly efficient exploration and development program resulting in a 164% replacement of production and finding and development costs of $7.62 per boe of proved plus probable reserves before revisions.
- Enhanced the internal inventory for future development by adding to the Trust's positions in key heavy oil areas.
- Strengthened the Trust's financial position with an equity issue in December to improve the flexibility for the funding of distributions and capital investments.

Operations Review

During the fourth quarter, Baytex participated in the drilling of 31 (26.0 net) wells, resulting in 26 (22.2 net) oil wells, one (1.0 net) gas well, three (1.8 net) service wells and one (1.0 net) dry hole for an average success rate of 96.8% (96.2% net). For 2003, Baytex participated in the drilling of 266 (243.4 net) wells, resulting in 173 (158.9 net) oil wells, 67 (61.4 net) gas wells, seven (5.1 net) service wells and 19 (18.0 net) dry holes. Overall success rate for the year was 92.9% (92.6% net).

Total capital spending for the year was $186.7 million, including $180.1 million on exploration and development and $6.6 million on acquisitions. Excluding spending in the Ferrier area, which assets were sold in March, and spending on the properties which were transferred to Crew Energy Inc. at the end of August, capital expenditures on the Trust's assets were $159.3 million during 2003. This program yielded excellent results as it replaced 164% of production and maintained the Trust's proved developed producing reserves at prior year levels. Finding and development costs of this program were $7.62 per boe of proved plus probable reserves before revisions and $11.26 per boe of proved reserves before revisions.

Significant expenditures were incurred in 2003 to enhance Baytex's position in areas of future development, with approximately $20 million spent on land and seismic costs during the year. In the Seal area of Alberta, currently one of the most active areas for heavy oil development in the Western Canadian Sedimentary Basin, Baytex has accumulated 58 sections of prospective land at 100% working interest, of which 44 sections were acquired in 2003. Baytex has designed a program in 2004 to test the oil quality and potential productivity of various prospects on its lands in Seal, which results will help set the plans for large scale development in this area in the coming years.

Production associated with the Trust's assets averaged approximately 35,000 boe per day in 2003. Baytex has established a 2004 capital budget between $100 million and $110 million for the development of its internal properties with the target of maintaining production at levels similar to those of 2003.

Financial Review

Cash flow, before reorganization costs, for the fourth quarter was $30.4 million which was negatively affected by the following factors:

(1) a weak U.S. dollar with an average exchange rate of 0.7600 during the fourth quarter compared to 0.6372 for the same quarter last year;
(2) oil hedging loss of $6.9 million which contracts expired at the end of 2003; and
(3) additional capital taxes payable of $1.2 million due to the dissolution of the Baytex Energy Partnership pursuant to the Plan of Arrangement leading to the trust conversion.

Distributions declared to the unitholders totaled $25.3 million for the fourth quarter of 2003, representing 84% of the cash flow available for distribution due to the non-recurring factors stated above. Under the Trust's comprehensive hedging program for 2004, and based on current commodity prices and production, the current monthly cash distribution of $0.15 per unit is estimated to be within the Trust's target distribution range of between 60% and 70% of cash flow.

At year-end 2003, the Trust had working capital of $19.0 million including $53.7 million of cash on deposit. The Trust's bank credit facilities totaling $165 million are entirely undrawn. Together with a conservative distribution policy which leaves 30% to 40% of cash flow for capital spending, Baytex is well positioned to fund its 2004 capital budget for the continuing development of its property inventory.

2003 Year-End Reserves

The Trust's oil and gas reserves as at January 1, 2004 were evaluated by Sproule Associates Limited. Sproule was appointed by the Board of Directors of Baytex in October 2003 as the new independent reserves evaluators for all of Baytex's oil and gas properties. Their evaluation report is prepared in accordance with National Instrument ("NI") 51-101, the new standards of disclosure for oil and gas activities as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

NI 51-101 replaces the former National Policy 2-B ("NP 2-B") and requires a higher degree of confidence in the assignment of oil and gas reserves. Under NI 51-101, proved reserves are defined to have a 90% probability that the actual reserves recovered will equal or exceed the assigned estimates compared to the previous definition of "reasonable certainty" as stipulated by NP 2-B. Also, under NI 51-101, probable reserves are defined to have a 50% probability that the actual reserves recovered will equal or exceed the assigned estimates compared to the previous definition of "likelihood of existence" in NP 2-B. Because of the more stringent requirements under NI 51-101, the industry has adopted the interpretation that the new proved plus probable (P-50) reserves represent the most "realistic" estimates of remaining recoverable reserves. The following reserves information also adopts the general industry practice of comparing the new P-50 reserves to the previous proved plus risk adjusted (50%) probable reserves, commonly referred to as "established reserves", under NP 2-B.

Under Sproule's NI 51-101 evaluation, technical revisions caused proved plus probable reserves for Baytex's light and medium crude oil, natural gas liquids and natural gas properties to increase by 9.2%, on a combined basis, compared to the prior year assignments. However, as explained by the following factors, proved plus probable reserves for Baytex's heavy oil properties were revised downward technically by 38.9%. Overall proved reserves at year-end 2003 totaled 76.7 million boe, a decrease of 34.5% compared to 117.2 million boe one year ago. Proved plus probable reserves at year-end 2003 were 106.3 million boe, a decrease of 26.7% compared to 145.1 million boe of established reserves at year-end 2002. These reductions are entirely on heavy oil reserves and are primarily due to the following reasons:

- the more stringent requirements under NI 51-101 compared to NP 2-B, causing recovery factors to be lowered and future drilling locations to be reduced which affected heavy oil properties that have previously been assigned a high percentage of proved developed non-producing and proved undeveloped reserves; and

- under the income trust structure, Baytex has adopted a policy of distributing between 60% and 70% of its cash flow to the unitholders, thereby reducing its annual capital programs compared to those of a growth-oriented exploration and production company. The size and length of the capital programs would impact the assigned probabilities, quantities and present value of the reported reserves.

The vast heavy oil resources underlying Baytex's asset base are estimated to be in excess of one billion barrels of oil equivalent in place. Technological improvement and production performance over time may increase future recovery factors, which could add significant realizable reserves to the existing properties of the Trust. Baytex will continue to focus on the prudent development of its assets to their full potential in order to maximize their value.

The 2003 year-end reserves report confirms the following key merits of the Trust:

- **Organic ability to replace produced-out reserves.** Proved developed producing reserves at year-end 2003 totaled 41.1 million boe compared to 40.8 million boe one year ago. Baytex was successful in organically replacing production during the year plus offsetting the impact of NI 51-101 as no material acquisitions were made during 2003. This validates the business strategy of the Trust which is focused on maintaining its production and asset base through internal property development while using selective acquisitions only to augment the development programs.

- **Conservative trading price to net asset value ratio.** Current trading price of Baytex trust units approximates 120% of the "produce-out" net asset value of $8.82 per unit, representing one of the lowest price to net asset value premiums within the oil and gas income trust sector.

- **Total resource potential not reflected in the NI 51-101 reserves report.** Under the stringent requirements of NI 51-101, no reserves have been recognized for the undeveloped, yet high potential, properties of Baytex including its significant holdings in the Seal heavy oil area. This is a unique characteristic of Baytex's asset base as oil and gas income trusts are generally comprised of mature producing assets. As Baytex proceeds with its exploitation and development programs in these areas, additional reserves could be recognized commensurate with the new disclosure standards.

- **Business plans and 2004 targets unaffected by reserve revisions.** The revisions in total proved and proved plus probable reserves have no impact on Baytex's 2004 production targets, as proved developed producing reserves have been maintained at levels comparable to those of one year ago. Baytex's current monthly cash distribution of $0.15 per unit is estimated to be within its target of distributing between 60% and 70% of cash flow, based on current production and commodity prices.

The following tables summarize certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule as at January 1, 2004. Additional information required under NI 51-101 will be included in the Annual Information Form to be filed for fiscal 2003.

Oil and Gas Reserves

	Forecast Prices and Costs					
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
Reserves Category	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)
Proved						
Developed Producing	3,724	3,445	24,795	22,442	249	174
Developed Non-Producing	144	127	15,204	13,119	9	6
Undeveloped	1,293	1,141	17,726	16,324	4	3
Total Proved	5,161	4,713	57,725	51,885	262	183
Probable	1,649	1,493	23,626	21,556	94	65
Total Proved Plus Probable	6,810	6,206	81,351	73,441	356	248

	Natural Gas		Oil Equivalent (3)	
Reserves Category	Gross (1) (Mmcf)	Net (2) (Mmcf)	Gross (1) (MBoe)	Net (2) (MBoe)
Proved				
Developed Producing	73,700	59,400	41,047	35,955
Developed Non-Producing	3,795	3,031	15,989	13,757
Undeveloped	4,080	3,169	19,703	17,996
Total Proved	81,575	65,600	76,739	67,708
Probable	24,725	20,000	29,561	26,492
Total Proved Plus Probable	106,300	85,600	106,300	94,200

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.
(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Reserves Life Index

	Q4/2003	Reserves Life Index (RLI)	
	Production	Total Proved	Proved Plus Probable
Crude Oil (bbl/d)	26,382	6.6	9.2
Natural Gas (mmcf/d)	58.9	3.8	5.0
Oil Equivalent (boe/d)	36,195	5.8	8.1

Net Present Value of Reserves

Summary of Net Present Value of Future Net Revenue
As at January 1, 2004
Forecast Prices and Costs

	Before Income Taxes Discounted at (%/year)			
Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)
Proved				
Developed Producing	521,400	472,500	427,900	391,900
Developed Non-Producing	135,600	107,700	88,400	74,300
Undeveloped	108,000	80,900	61,000	46,100
Total Proved	765,000	661,100	577,300	512,300
Probable	276,700	203,200	156,100	123,900
Total Proved Plus Probable	1,041,700	864,300	733,400	636,200

Sproule January 1, 2004 Price Forecast

Year	WTI Cushing US$/Bbl	Edmonton Par Price C$/Bbl	Hardisty Heavy 12 API C$/Bbl	AECO C-Spot C$/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2004	29.63	37.99	23.80	6.04	1.5	0.75
2005	26.80	34.24	21.28	5.36	1.5	0.75
2006	25.76	32.87	20.80	4.80	1.5	0.75
2007	26.14	33.37	21.33	4.91	1.5	0.75
2008	26.53	33.87	21.84	4.98	1.5	0.75
2009	26.93	34.38	22.31	5.05	1.5	0.75
2010	27.34	34.90	22.80	5.14	1.5	0.75

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves in its existing properties beyond those included in the 2003 year-end report.

Proved plus probable reserves (1)	$ 733,400,000
Undeveloped land (2)	51,115,000
Net debt (3)	(213,572,000)
Net asset value	$ 570,943,000
Total trust units outstanding (4)	64,715,000
Net asset value per trust unit	$ 8.82

Notes:

(1) As evaluated by Sproule as at January 1, 2004 discounted at 10%. Net present value of future net revenue does not represent fair market value of the reserves.
(2) As evaluated by Charter Land Services Ltd. as at December 31, 2003 on 737,000 net acres of undeveloped land.
(3) Long-term debt net of working capital as at December 31, 2003.
(4) Includes 60,821,000 trust units outstanding as at December 31, 2003 plus 3,725,000 exchangeable shares converted at an exchange ratio of 1.04530.

Reserves Reconciliation

Reconciliation of Company Interest Reserves
By Principal Product Type
Forecast Prices and Costs

Factors	Light and Medium Crude Oil			Heavy Oil		
	Proved [1] (Mbbl)	Probable [1] (Mbbl)	Proved + Probable [1] (Mbbl)	Proved [1] (Mbbl)	Probable [1] (Mbbl)	Proved + Probable [1] (Mbbl)
December 31, 2002 [2]	3,589	1,142	4,731	100,914	24,471	125,385
Capital Additions [3]	1,931	560	2,491	8,850	4,602	13,452
Technical Revisions	207	(63)	144	(43,345)	(5,447)	(48,792)
Acquisitions	80	10	90	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production [4]	(646)	-	(646)	(8,694)	-	(8,694)
January 1, 2004	5,161	1,649	6,810	57,725	23,626	81,351

Factors	Natural Gas Liquids			Natural Gas		
	Proved [1] (Mbbl)	Probable [1] (Mbbl)	Proved+ Probable [1] (Mbbl)	Proved [1] (Mmcf)	Probable [1] (Mmcf)	Proved + Probable [1] (Mmcf)
December 31, 2002 [2]	81	24	105	75,573	13,521	89,094
Capital Additions [3]	69	12	81	17,925	9,249	27,174
Technical Revisions	146	58	204	7,051	1,677	8,728
Acquisitions	-	-	-	1,386	278	1,664
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production [4]	(34)	-	(34)	(20,360)	-	(20,360)
January 1, 2004	262	94	356	81,575	24,725	106,300

Factors	Oil Equivalent [5]		
	Proved [1] (MBoe)	Probable [1] (MBoe)	Proved + Probable [1] (MBoe)
December 31, 2002 [2]	117,180	27,890	145,070
Capital Additions [3]	13,837	6,715	20,552
Technical Revisions	(41,821)	(5,100)	(46,921)
Acquisitions	311	56	367
Dispositions	-	-	-
Economic Factors	-	-	-
Production [4]	(12,768)	-	(12,768)
January 1, 2004	76,739	29,561	106,300

Notes:

(1) Reserves information as at December 31, 2002 is prepared in accordance with NP 2-B. Probable reserves as at December 31, 2002 represents 50% of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at January 1, 2004.

(2) As disclosed in the Information Circular dated July 25, 2003 of Baytex Energy Ltd. with respect to the Plan of Arrangement resulting in the formation of Baytex Energy Trust. Reserves information based on an independent engineering evaluation of the oil and gas reserves of Baytex Energy Ltd. as at December 31, 2002 prepared by Outtrim Szabo Associates Ltd. and adjusted by Baytex after giving effect to the transfer of certain oil and gas properties to Crew Energy Inc. pursuant to the Plan of Arrangement and the sale of oil and gas assets in the Ferrier area in March 2003.

(3) Includes Discoveries, Extensions and Improved Recoveries.

(4) Production for the year ended December 31, 2003 excludes production associated with the oil and gas properties transferred to Crew Energy Inc. pursuant to the Plan of Arrangement and production associated with the oil and gas assets disposed in the Ferrier area.

(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Management's Discussion and Analysis

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. (the "Company") transferred to Crew Energy Inc. ("Crew") a portion of the producing and exploratory oil and natural gas assets. For each common share of the Company, 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. 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 the Company.

Management's discussion and analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended December 31, 2003 and the year ended December 31, 2003 and the audited consolidated financial statements and MD&A for the year ended December 31, 2002. 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 is 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 fourth quarter of 2003 decreased by 32% to 1,982 bbl/d from 2,909 bbl/d a year earlier due to the sale of properties in March 2003 in the Ferrier area and the transfer of properties to Crew in September 2003. Heavy oil production decreased by 2% to 24,400 bbl/d for the fourth quarter of 2003 from 25,009 bbl/d a year ago. Natural gas production decreased by 18% to 58.9 mmcf/d compared to 71.8 mmcf/d for the same period last year due to the sale of the Ferrier properties and the transfer of properties to Crew.

For the year ended December 31, 2003, light oil production decreased by 28% to 2,273 bbl/d from 3,154 bbl/d last year. Heavy oil production remained constant at 23,911 bbl/d for 2003 compared to 23,967 bbl/d for 2002. Natural gas production decreased by 13% to average 63.0 mmcf/d for 2003 compared to 72.6 mmcf/d for 2002. These production changes were due to the same factors as noted for the fourth quarter comparisons.

Revenue. Petroleum and natural gas sales decreased 23% to $77.9 million for the fourth quarter of 2003 from $100.6 million for the fourth quarter of 2002. For fiscal 2003, petroleum and natural gas sales decreased by 4% to $351.4 million in 2003 from $365.9 million a year earlier.

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2003 were 605 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 twelve months ended December 31, 2003 was 650 barrels per day.

	Three Months ended December 31			
	2003		2002	
	$000s	$/Sales Unit	$000s	$/Sales Unit
Oil revenue (barrels)				
Light oil	6,637	36.41	10,081	37.67
Heavy oil	49,038	22.40	60,027	26.09
Derivative contracts loss	(6,918)	(2.92)	(4,046)	(1.58)
Total oil revenue	48,757	20.56	66,062	25.72
Natural gas revenue (mcf)	29,112	5.37	34,984	5.29
Derivative contracts loss	-	-	(456)	(0.07)
Total natural gas revenue	29,112	5.37	34,528	5.22
Total revenue (boe @ 6:1)	77,869	23.78	100,590	27.41

Revenue from light oil for the fourth quarter of 2003 decreased 34% from the same period a year ago due to a 32% decrease in production and a 3% decrease in wellhead prices. Revenue from heavy oil decreased 18% as production decreased by 5% and wellhead prices decreased by 14%. Revenue from natural gas decreased 17% as the 2% increase in wellhead prices was offset by a 18% decrease in production.

	Year ended December 31			
	2003		2002	
	$000s	$/Unit	$000s	$/Unit
Oil revenue (barrels)				
Light oil	32,393	39.04	38,985	33.86
Heavy oil	213,297	25.12	230,874	26.39
Derivative contracts loss	(33,777)	(3.62)	(10,622)	(1.07)
Total oil revenue	211,913	22.74	259,237	26.19
Natural gas revenue (mcf)	139,491	6.07	104,284	3.94
Derivative contracts gain	-	-	2,339	0.09
Total natural gas revenue	139,491	6.07	106,623	4.03
Total revenue (boe @ 6:1)	351,404	26.72	365,860	25.56

For the year 2003, light oil revenue decreased 17% from last year due to a 15% increase in wellhead prices offsetting a 28% decrease in production. Revenue from heavy oil decreased 8% due to a 5% decrease in wellhead prices and a 3% decrease in production. Revenue from natural gas increased 34% as wellhead prices increased 54% and production decreased 13% compared to 2002.

Royalties. Total royalties decreased 19% to $13.5 million for the fourth quarter of 2003 from $16.7 million for the same period in 2002. The decrease is the result of lower production revenue for the period. Total royalties for the fourth quarter of 2003 were 15.9% of sales compared to 15.8% of sales for the same period in 2002. For the fourth quarter of 2003, royalties were 14.9% of sales for light oil, 12.0% for heavy oil and 22.7% for natural gas. These rates compared to 18.5%, 13.1% and 19.7%, respectively, for the same period in 2002.

For the year ended December 31, 2003, royalties increased 14% to $67.2 million from $58.9 million for last year and were 17.4% of sales compared to 15.7% of sales in 2002. Higher realized gas prices resulted in higher royalty rates. Royalties for the year 2003 were 17.8% of sales for light oil, 13.8% for heavy oil and 22.9% for natural gas. These rates compared to 16.7%, 13.9% and 19.5%, respectively, for 2002.

Operating Expenses. Operating expenses for the fourth quarter of 2003 increased 11% to $22.1 million from $19.8 million for the corresponding quarter last year. Operating expenses were $6.74 per boe for the fourth quarter of 2003 compared to $5.40 per boe for the fourth 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 fourth quarter of 2003, operating expenses were $10.42 per barrel of light oil, $7.44 per barrel of heavy oil and $0.72 per mcf of natural gas. The operating expenses for the same period a year ago were $5.15, $6.22 and $0.62, respectively.

Operating expenses for the year 2003 increased 14% to $86.0 million from $75.2 million for 2002. This increase is primarily due to the same factors as noted in the fourth quarter comparison. Operating expenses were $6.54 per boe for the year 2003 compared to $5.26 per boe for the prior year. Operating expenses were $8.32 per barrel of light oil, $7.34 per barrel of heavy oil and $0.73 per mcf of natural gas for 2003 versus $5.83, $5.99 and $0.61, respectively, for 2002

General and Administrative Expenses. General and administrative expenses, excluding non-cash stock-based compensation expenses, for the fourth quarter of 2003 were $3.6 million compared to $1.6 million in 2002. On a per sales unit basis, these expenses were $1.07 per boe compared to $0.44 per boe as no expenses were capitalized in the fourth quarter of 2003 and $1.6 million was capitalized in the same quarter last year. 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, excluding non-cash stock-based compensation expenses, for the year 2003 were $8.9 million, compared to $6.7 million a year ago. On a per sales unit basis, these expenses increased to $0.67 per boe from $0.47 per boe. In accordance with the full cost accounting policy, $4.4 million of expenses were capitalized in 2003, compared with $6.7 million capitalized in 2002.

Interest Expenses. Interest expenses on long-term notes and bank debt were $5.2 million for the fourth quarter of 2003, down from $7.2 million in the same quarter last year. The decrease is due to the redemption of the senior secured term notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses. For the year 2003, interest expenses on long-term debt were $23.5 million compared to $25.2 million for 2002.

Costs on Redemption and Exchange of Notes. On July 9, 2003, the Company completed an exchange offer related to its outstanding US$150 million 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-cash loss of $40.0 million on the completion of the exchange offer, which was recognized in income. Also included in the costs is a $4.7 million loss recognized in May 2003 on the redemption of the US$57 million senior secured notes.

Foreign Exchange. The foreign exchange gain in the fourth quarter of 2003 was $10.4 million compared to a gain of $1.3 million in the same period last year. The gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7737 at December 31, 2003 compared to 0.7405 at September 30, 2003. The 2002 gain is based on translation at 0.6331 at December 31, 2002 compared to 0.6306 at September 30, 2002.

The foreign exchange gain for the year 2003 was $52.1 million compared to $2.7 million in 2002. The 2003 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002. The 2002 gain is based on translation at 0.6331 at December 31, 2002 compared to 0.6279 at December 31, 2001.

Depletion and Depreciation. The provision for depletion and depreciation increased to $40.4 million for the fourth quarter of 2003 compared to $27.1 million for the same quarter a year ago. On a per sales unit basis, the provision for the current quarter was $12.14 per boe compared to $7.39 per boe for the same quarter in 2002 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument ("NI") 51-101, as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

Depletion and depreciation increased to $116.3 million for the year 2003 compared to $106.8 million for last year. On a per sales unit basis, the provision for 2003 was $8.69 per boe compared to $7.46 per boe for 2002. No additional provision for depletion and depreciation was required under the full cost accounting ceiling test applied at the end of 2003.

Site Restoration. The current quarter provision for site restoration was $1.3 million compared to $0.7 million for the same quarter last year. On a per sales unit basis, the provision for the fourth quarter of 2003 was $0.41 per boe compared to $0.19 per boe for the corresponding quarter of last year due the changes in the proved reserves used in the calculation.

Site restoration costs for the year ended December 31, 2003 increased to $3.0 million from $2.8 million last year. On a per sales unit basis, the provision for 2003 was $0.22 per boe compared to $0.20 per boe for 2002.

Income Taxes. Current tax expenses were $3.5 million for the fourth quarter of 2003 compared to $2.4 million for the same quarter a year ago. The increase is due to additional taxes payable as a result of the dissolution of the Baytex Energy Partnership. The current tax expense is comprised of $2.7 million of Saskatchewan Capital Tax and $0.8 million of Large Corporation Tax compared to $2.0 million and $0.4 million, respectively, in the corresponding period in 2002.

Current tax expenses were $9.7 million for 2003 compared to $9.7 million last year. The 2003 current tax expense is comprised of $8.0 million of Saskatchewan Capital Tax and $1.7 million of Large Corporation Tax compared to $8.1 million and $1.6 million, respectively, in 2002.

Net Income. Net income for the fourth quarter of 2003 was $8.9 million compared to $12.8 million for the corresponding quarter of 2002. Net income for 2003 decreased to $38.1 million from $45.1 million for 2002. In 2003, increased depletion expense, costs on the redemption and exchange of notes and reorganization costs were offset by foreign exchange gains and a recovery of future income taxes.

Liquidity and Capital Resources. At December 31, 2003, total net debt (including working capital) was $213.6 million compared to $267.8 million at September 30, 2003 and $362.8 million at December 31, 2002. The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from assets sales at the end of March 2003 and an equity issue of 6.5 million trust units in December 2003.

On September 3, 2003, the Company entered into a new credit agreement with a 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 December 31, 2003, there were no amounts outstanding under the bank credit facilities.

Capital Expenditures. Exploration and development expenditures increased to $180.1 million for 2003 compared to $136.3 million last year. The Trust's total capital expenditures for the last two years are summarized as follows:

	Year ended December 31	
($ thousands)	2003	2002
Land	14,138	13,834
Seismic	5,436	8,183
Drilling and completion	111,772	81,562
Equipment	42,365	24,507
Other	6,401	7,949
Total exploration and development	180,112	136,335
Property acquisitions	6,644	45,713
Property dispositions	(137,493)	(55,580)
Net capital expenditures	49,263	126,468

Conference Call

Baytex will host a conference call and question and answer session at 2:00 p.m. MT (4:00 p.m. ET) on Wednesday, March 10, 2004 to discuss its operating and financial results for the quarter and year ended December 31, 2003. The conference call will be hosted by Raymond Chan, President and Chief Executive Officer, Dan Belot, Vice-President, Finance and Chief Financial Officer and Randy Best, Vice-President, Corporate Development.

Baytex Energy Trust Conference Call
Toll-Free across North America: 1-800-847-8137

A recorded playback of the call will also be made available from
March 10 until March 24, 2004
Toll-free across North America: 1-800-558-5253
Within Toronto and area: 416-626-4100
Enter Reservation # 21183196

The conference call will be archived on Baytex's website at www.baytex.ab.ca.

Forward-Looking Statements

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to Management's approach to operations and Baytex's production, cash flow, debt levels and oil and gas reserves 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 Baytex's areas of operations; and other factors, many of which are beyond the control of Baytex. 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 is ranked amongst the top five conventional oil and gas income trusts by production in Canada. Baytex is focused on maintaining its production and asset base through internal property development and delivering consistent returns to its unitholders. Trust units of Baytex are traded on the Toronto Stock Exchange under the symbol BTE.UN.

Financial statements for the periods ended December 31, 2003 and 2002 are attached.

FOR DETAILED INFORMATION, PLEASE CONTACT:

Ray Chan, President & C.E.O. Telephone: (403) 267-0715
Dan Belot, Vice-President, Finance & C.F.O. Telephone: (403) 267-0784

Toll Free Number: 1-800-524-5521
Website: www.baytex.ab.ca

Baytex Energy Trust
Consolidated Balance Sheets
(thousands) (Unaudited)

	December 31, 2003	December 31, 2002
Assets		
Current assets		
Cash and short-term investments	**$ 53,731**	$ 4,098
Accounts receivable	**48,608**	52,667
Crude oil inventory	**5,900**	-
	108,239	56,765
Deferred charges and other assets	**7,764**	8,679
Petroleum and natural gas properties	**843,133**	932,316
	$ 959,136	$ 997,760
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 80,126**	$ 92,563
Distributions payable to unitholders	**9,123**	-
	89,249	92,563
Long-term debt (note 5)	**232,562**	326,977
Deferred credits	**-**	12,181
Provision for future site restoration costs	**23,483**	21,950
Future income taxes	**174,385**	184,402
	519,679	638,073
Unitholders' Equity		
Unitholders' capital (note 8)	**446,594**	398,176
Exchangeable shares (note 8)	**26,372**	-
Contributed surplus (note 9)	**224**	-
Accumulated distributions	**(33,382)**	-
Accumulated deficit	**(351)**	(38,489)
	439,457	359,687
	$ 959,136	$ 997,760

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Operations and Accumulated Deficit
(thousands, except per unit data) (Unaudited)

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
Revenue				
Petroleum and natural gas	**$ 77,869**	$ 100,590	**$ 351,404**	$ 365,860
Royalties	**(13,498)**	(16,652)	**(67,175)**	(58,922)
	64,371	83,938	**284,229**	306,938
Expenses				
Operating	**22,066**	19,804	**86,034**	75,228
General and administrative	**3,570**	1,619	**8,927**	6,743
Unit-based compensation (note 9)	**739**	-	**739**	-
Interest (note 5)	**5,173**	7,218	**23,548**	25,217
Costs on redemption and exchange of notes (note 5)	**-**	-	**44,771**	-
Foreign exchange gain	**(10,437)**	(1,283)	**(52,101)**	(2,691)
Depletion and depreciation	**40,423**	27,137	**116,317**	106,834
Site restoration	**1,349**	697	**2,973**	2,799
Reorganization costs (note 4)	**209**	-	**18,851**	-
	63,092	55,192	**250,059**	214,130
Income before income taxes	**1,279**	28,746	**34,170**	92,808
Income taxes (recovery)				
Current	**3,450**	2,446	**9,663**	9,716
Future (note 7)	**(11,052)**	13,509	**(13,631)**	37,956
	(7,602)	15,955	**(3,968)**	47,672
Net income	**$ 8,881**	$ 12,791	**38,138**	45,136
Accumulated deficit, beginning of year			**(38,489)**	(75,954)
Accounting policy change for foreign exchange			**-**	(7,671)
Accumulated deficit, beginning of year, as restated			**(38,489)**	(83,625)
Accumulated deficit, end of year			**$ (351)**	$ (38,489)
Net income per trust unit				
Basic	**$ 0.15**	$ 0.24	**$ 0.69**	$ 0.86
Diluted	**$ 0.15**	$ 0.24	**$ 0.67**	$ 0.85

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
(thousands, except per unit data) (Unaudited)

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net income	**$ 8,881**	$ 12,791	**$ 38,138**	$ 45,136
Items not affecting cash:				
Unit-based compensation	**739**	-	**739**	-
Amortization of deferred charges	**276**	265	**1,027**	1,052
Costs on redemption and exchange of notes	**-**	-	**44,771**	-
Foreign exchange gain	**(10,437)**	(1,283)	**(52,101)**	(2,691)
Depletion and depreciation	**40,423**	27,137	**116,317**	106,834
Site restoration costs	**1,349**	697	**2,973**	2,799
Future income taxes (recovery)	**(11,052)**	13,509	**(13,631)**	37,956
Cash flow from operations	**30,179**	53,116	**138,233**	191,086
Change in non-cash working capital	**(5,097)**	14,400	**(8,060)**	1,272
(Increase) decrease in deferred charges and other assets	**53**	(1,057)	**211**	(1,057)
Decrease in deferred credits	**-**	(4,712)	**(2,213)**	(18,694)
	25,135	61,747	**128,171**	172,607
FINANCING ACTIVITIES				
Redemption of senior secured notes	**-**	-	**(89,950)**	-
Decrease in bank loan and other debt	**-**	-	**-**	(76,254)
Increase in deferred charges and other assets	**(38)**	-	**(7,425)**	
Increase (decrease) in deferred credits	**-**	(1,125)	**-**	12,181
Issue of trust units	**61,525**	-	**61,525**	-
Payment of distributions	**(24,259)**	-	**(24,259)**	-
Issue of common shares	**-**	924	**37,049**	3,497
Repurchase of common shares	**-**	-	**-**	(55)
	37,228	(201)	**(23,060)**	(60,631)
INVESTING ACTIVITIES				
Petroleum and natural gas property expenditures	**(22,801)**	(68,398)	**(186,756)**	(182,048)
Disposal of petroleum and natural gas properties	**218**	1,152	**137,493**	55,580
Properties held for sale	**-**	-	**-**	(46,895)
Change in non-cash working capital	**(9,256)**	(1,639)	**(6,215)**	65,485
	(31,839)	(68,885)	**(55,478)**	(107,878)
Change in cash and short-term investments	**30,524**	(7,339)	**49,633**	4,098
Cash and short-term investments, beginning of period	**23,207**	11,437	**4,098**	-
Cash and short-term investments, end of period	**$ 53,731**	$ 4,098	**$ 53,731**	$ 4,098

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements
Three Months and Year Ended December 31, 2003 and 2002
(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, the Company transferred to Crew a portion of the producing and exploratory oil and natural gas assets. For each common share of the Company, 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. Subsequent to the Plan of Arrangement, 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 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 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, except as described in note 3. The 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 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. Changes in Accounting Policy

Unit-Based Compensation Plan

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. Compensation expense of $0.22 million was recorded for all trust unit rights granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus, which was reclassified to trust units when the options were exercised. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (see note 9).

4. Transfer of Assets and Liabilities Pursuant to Plan of Arrangement

Under the Plan of Arrangement (note 1), the Company transferred to Crew 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 carrying value as follows:

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

Reorganization costs of $18.9 million were expensed in the consolidated statements of operations as a result of the Plan of Arrangement.

5. Long-term Debt

	December 31, 2003	December 31, 2002
Senior secured notes (2002 - US$57,000,000)	**$ -**	$ 90,037
10.5% Senior subordinated notes (2003 - US$247,000; 2002 – US$150,000,000)	**319**	236,940
9.625% Senior subordinated notes (US$179,699,000)	**232,243**	-
	$ 232,562	$ 326,977

In May 2003, the Company redeemed the outstanding senior secured notes for a total cash payment of $90.0 million, resulting in a loss of $4.7 million on the redemption.

On July 9, 2003, the Company completed an exchange offer related to its outstanding US$150 million 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-cash loss of $40.0 million on the completion of the exchange offer, which was recognized in income.

Interest Expense

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

	Three Months Ended December 31		**Year Ended December 31**	
	2003	2002	**2003**	2002
Bank loan	**$ 114**	$ 229	**$ 675**	$ 760
Amortization of deferred charge	**276**	265	**1,027**	1,052
Long-term debt	**4,783**	6,724	**21,846**	23,405
Total interest	**$ 5,173**	$ 7,218	**$ 23,548**	$ 25,217

6. Bank Credit Facilities

On September 3, 2003, the Company entered into a new credit agreement with a 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 December 31, 2003, there were no amounts outstanding under the bank credit facilities.

7. Income Taxes

Income tax expense for the periods ended December 31, 2003 includes 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

Trust Units

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53,304,858 trust units and 4,732,326 exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company.

On December 12, 2003, the Trust issued 6,500,000 trust units at $10.00 per unit for proceeds of $65 million pursuant to a prospectus.

Trust Units	**# of units**	**Amount**
Issued September 2, 3003 pursuant to Plan of Arrangement	53,305	$ 377,419
Issued on conversion of Exchangeable Shares	1,016	7,135
Stock-based compensation	-	515
Issued for cash, net of expenses	6,500	61,525
Balance December 31, 2003	60,821	$ 446,594

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 cash 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 December 31, 2003 was 1.04530 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**
Issued September 2, 3003 pursuant to Plan of Arrangement	4,732	$ 33,507
Exchanged for trust units	(1,007)	(7,135)
Balance December 31, 2003	3,725	$ 26,372

Under the Plan of Arrangement, shareholders of the Company received one unit of the Trust or one Exchangeable Share and one-third of a share in Crew 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 (note 4)	-	(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 December 31, 2003	-	$ -

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 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 year ended December 31, 2003 was $0.22 million.

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

	# of Rights	Weighted average exercise price (1)
Initial grant September 9, 2003	2,593	$ 10.23
Granted	380	$ 9.60
Cancelled	(118)	$ 10.23
Balance December 31, 2003	2,855	$ 10.15

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

The Company had a stock option plan prior to the Plan of Arrangement. The outstanding stock options of the Company were exercised during 2003.

	# 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 December 31, 2003	-	-

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. Compensation expense of $0.52 million was recorded for all stock options granted by the Company on or after January 1, 2003, with a corresponding amount recorded as contributed surplus, with expenses in the first and second quarters increased by $0.32 million and $0.20 million, respectively. Accordingly, quarterly net income in such quarters previously reported as $32.9 million and $41.8 million would be revised to $32.6 million and $41.6 million, respectively. There were no changes to the expenses or the net loss of the third quarter.

Compensation expense for options granted during 2003 was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option. For options granted prior to January 1, 2003, the pro forma earnings impact of related stock based compensation expense is as follows:

	Three Months Ended December 31		***Year Ended December 31***	
	2003	2002	**2003**	2002
Net income as reported	**$ 8,881**	$12,791	**$38,138**	$45,136
Stock based compensation expense	**(4,433)**	(70)	**(5,522)**	(612)
Pro forma net income	**$ 4,448**	$12,721	**$32,616**	$44,524
Net income per unit				
Basic as reported	**$ 0.15**	$ 0.24	**$ 0.69**	$ 0.86
Pro forma	**$ 0.07**	$ 0.24	**$ 0.59**	$ 0.85
Diluted as reported	**$ 0.15**	$ 0.24	**$ 0.67**	$ 0.85
Pro forma	**$ 0.07**	$ 0.24	**$ 0.58**	$ 0.83

The weighted average fair market value of options granted during the year ended December 31, 2003 was $4.21 per option (2002 - $3.65 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 four percent; expected life of four years and expected volatility of 52 percent.

10. Derivative Contracts

At December 31, 2003, the Trust had derivative contracts for the following:

	Period	**Volume**	**Price**	**Index**
Oil				
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

The fair value of the oil derivative contracts at December 31, 2003 is an unrecognized liability of $13.8 million.

	Period	**Amount**	**Exchange Rate**	
Foreign currency			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

The fair value of the foreign currency contracts at December 31, 2003 is an unrecognized asset of $3.7 million.

	Period	**Fixed Rate**	**Floating Rate**
Interest rate swap	**US$ 179,699,000**		
	November 2003 to July 2010	9.625%	3-month LIBOR plus 5.2%

The fair value of the interest rate swap at December 31, 2003 is an unrecognized asset of $3.9 million.

11. Supplemental Cash Flow Information

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
Interest paid	**2,161**	4,802	**24,449**	25,482
Income taxes paid (refunded)	**1,756**	688	**12,557**	(3,298)