The following discussion and analysis, dated March 5, 2004, should be read in conjunction with Baytex Energy Trust's (the "Trust") audited consolidated financial statements for the fiscal years ended December 31, 2003 and 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.

The Trust evaluates performance based on net income and cash flow from operations. 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.

2003 OVERVIEW

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 its producing and exploratory petroleum and natural gas assets. As Crew was a related party at the effective date of the Plan of Arrangement, the assets and liabilities were transferred at book value. 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. The Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company, 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.

Production

The Trust's average production for fiscal 2003 decreased by six percent to 36,686 boe per day from 39,214 boe per day for fiscal 2002. This decrease was the result of property dispositions that occurred at the end of the first quarter of 2003 and the transfer of the petroleum and natural gas assets to Crew under the Plan of Arrangement effective September 2, 2003.

Light oil production decreased 28 percent to 2,273 barrels per day during 2003 from 3,154 barrels per day in 2002. Heavy oil production during 2003 was 23,911 barrels per day, consistent with production of 23,967 barrels per day during fiscal 2002. Natural gas production for 2003 decreased by 13 percent to 63.0 million cubic feet per day compared to 72.6 million cubic feet per day for the prior year.

Revenue

Petroleum and natural gas sales for 2003 decreased by four percent to $351.4 million from $365.9 million for fiscal 2002. Benchmark WTI crude oil averaged US$31.04 per barrel for 2003, representing a 19 percent increase over the US$26.08 per barrel for 2002. Correspondingly, the Trust's light oil and NGLs price increased to $39.04 per barrel from $33.86 per barrel in 2002. The heavy oil price decreased five percent to $25.12 per barrel in 2003 from $26.39 per barrel in 2002, principally due to the increase in heavy oil differentials. Natural gas prices were 54 percent higher in 2003, averaging $6.07 per thousand cubic feet compared to $3.94 per thousand cubic feet during the previous year. Overall, after accounting for financial derivative contracts, the Trust averaged $26.72 per boe for 2003, a 4 percent increase from $25.56 per boe received in the prior year. For the per-sales-unit calculations, heavy oil sales for 2003 were 650 barrels per day lower than the production for the year due to inventory in transit under the Frontier supply agreement.

For 2003, light oil revenue decreased 17 percent over 2002, as the 15 percent increase in wellhead prices was offset by a 28 percent decrease in production. Revenue from heavy oil

Production by Area	Light Oil and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Barrels of Oil Equivalent (boe/d)
2003				
Heavy Oil District	**–**	**23,911**	**10.6**	**25,676**
Conventional Oil and Gas District	**2,273**	**–**	**52.4**	**11,010**
Total Production	**2,273**	**23,911**	**63.0**	**36,686**
2002				
Heavy Oil District	–	23,967	10.5	25,710
Conventional Oil and Gas District	3,154	–	62.1	13,504
Total Production	3,154	23,967	72.6	39,214

decreased eight percent due to a five percent decrease in wellhead prices and a three percent decrease in sales volumes. Natural gas revenue increased 34 percent as the 13 percent production decrease was offset by a 54 percent increase in wellhead prices.

Royalties

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

Operating Expenses

Operating expenses for 2003 increased 14 percent to $86.0 million from $75.2 million for 2002. This increase is attributable to the disposition of properties with lower operating costs and a general increase in field operating costs. Operating expenses were $6.54 per boe for 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 thousand cubic feet of natural gas for 2003 versus $5.83, $5.99 and $0.61, respectively, for 2002.

Gross Revenue Analysis

	2003		2002	
	$ thousands	**$/Unit[1]**	$ thousands	$/Unit[1]
Light oil	**32,393**	**39.04**	38,985	33.86
Heavy oil	**213,297**	**25.12**	230,874	26.39
Derivative contract loss	**(33,777)**	**(3.62)**	(10,622)	(1.07)
Total oil revenue	**211,913**	**22.74**	259,237	26.19
Natural gas revenue	**139,491**	**6.07**	104,284	3.94
Derivative contract 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

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

Operating Netback

	Light Oil & NGLs ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGLs ($/bbl)		Natural Gas ($/mcf)		BOE ($/boe)	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Sales price	**39.04**	33.86	**25.12**	26.39	**26.36**	27.26	**6.07**	3.94	**29.28**	26.14
Royalties	**(6.96)**	(5.67)	**(3.47)**	(3.66)	**(3.78)**	(3.89)	**(1.39)**	(0.77)	**(5.11)**	(4.12)
Operating costs	**(8.32)**	(5.83)	**(7.34)**	(5.99)	**(7.43)**	(5.97)	**(0.73)**	(0.61)	**(6.54)**	(5.26)
Operating netback	**23.76**	22.36	**14.31**	16.74	**15.15**	17.40	**3.95**	2.56	**17.63**	16.76

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses

General and administrative expenses for 2003 were $8.9 million, compared to $6.7 million a year ago. On a 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. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Unit-based Compensation

The Trust accounts 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 consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003.

Compensation expense was also calculated on the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as compensation expense for all stock options granted on or after January 1, 2003. All outstanding stock options were cancelled or exercised effective September 2, 2003.

Interest Expense

For 2003, interest expenses on long-term debt were $23.5 million compared to $25.2 million for 2002. The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

Costs on Redemption and Exchange of Notes

On July 9, 2003, the Company completed an exchange offer related to its previously outstanding US$150 million 10.5 percent senior subordinated notes due 2011 (the "Old Notes"). The Company issued US$179.7 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-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. Also recognized in income is $4.7 million of costs on the redemption of the US$57 million senior 7.23 percent secured notes.

Depletion and Depreciation

Depletion and depreciation increased to $116.3 million for 2003 compared to $106.8 million last year. On a sales-unit basis, the provision for 2003 was $8.69 per boe compared to $7.46 per boe for 2002 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument 51-101 ("NI 51-101"), as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

General and Administrative Expenses

($ thousands)	2003	2002
Gross corporate expense	$ **20,496**	$ 19,328
Operator's recoveries	**(7,166)**	(5,842)
Subtotal	**13,330**	13,486
Full-cost accounting capitalization	**(4,403)**	(6,743)
Net expense	$ **8,927**	$ 6,743

The ceiling test was calculated at December 31, 2003 using the proved reserves as determined under NI 51-101 and at prices at year-end. No write-down was required at December 31, 2003 under this calculation.

Site Restoration Costs

Site restoration costs for the year ended December 31, 2003 increased to $2.9 million from $2.8 million last year. On a sales-unit basis, the provision for 2003 was $0.22 per boe compared to $0.20 per boe for 2002 due to the changes in the proved reserves used in the calculation.

Foreign Exchange

Foreign exchange gain for 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.

Income Taxes

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.

The fiscal 2003 provision for future income taxes was a recovery of $13.6 million compared to $37.9 million for the prior year. The future income tax recovery for 2003 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income. The federal resource tax changes include a change in the federal income tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over the next five years. These changes are considered substantially enacted for the purposes of GAAP and the Company's future income tax liability has been reduced accordingly.

Canadian Tax Pools

($ thousands)	**December 31, 2003**
Cumulative Canadian exploration expense	**9,000**
Cumulative Canadian development expense	**63,000**
Cumulative Canadian oil and gas property expense	**96,000**
Undepreciated capital cost	**148,000**
Other	**48,000**
Total tax pools	**364,000**

Cash Flow from Operations

Cash flow from operations for the year ended December 31, 2003 decreased 28 percent to $138.2 million from $191.1 million for the previous year due to higher costs related to derivative contracts and reorganization under the Plan of Arrangement. On a barrel of oil equivalent basis, cash flow from operations was $10.51 for 2003 compared to $13.35 for 2002.

Capital Expenditures

Exploration and development expenditures increased to $180.1 million for 2003 compared to $136.3 million last year. Total capital expenditures for the last two years are summarized in the table below.

Liquidity and Capital Resources

At December 31, 2003, total net debt (including working capital) was $213.6 million compared to $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 for net proceeds of $61.5 million in December 2003.

The Company's debt structure consists of two components. The first component is the senior credit facilities. On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. The credit

Cash Flow

	2003		2002	
	$/boe	Percent	$/boe	Percent
Production revenue	**29.28**	**100**	26.14	100
Derivative contract loss	**(2.57)**	**(9)**	(0.57)	(2)
Royalties	**(5.11)**	**(17)**	(4.12)	(16)
Operating expenses	**(6.54)**	**(22)**	(5.26)	(20)
Operating netback	**15.06**	**52**	16.19	62
General and administrative expenses	**(0.68)**	**(2)**	(0.47)	(2)
Reorganization costs	**(1.43)**	**(5)**	–	–
Interest expense	**(1.71)**	**(6)**	(1.69)	(6)
Current income taxes	**(0.73)**	**(3)**	(0.68)	(3)
Cash flow	**10.51**	**36**	13.35	51

Capital Expenditures

($ thousands)	2003	2002
Land	**$ 14,138**	$ 13,834
Seismic	**5,436**	8,183
Drilling and completion	**111,772**	81,862
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

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 reviews 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.

The second component is the senior subordinated notes. On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities. On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million ($247.1 million) of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") 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 this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank credit facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53.3 million trust units and 4.7 million exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company. An additional 6.5 million trust units were issued on December 12, 2003 for gross proceeds of $65 million.

At December 31, 2003, there were 3.7 million exchangeable shares outstanding. The exchange ratio of these shares was 1.04530 trust units per exchangeable share at year-end. During 2003, a total of 1.0 million exchangeable shares were exchanged for trust units.

Cash Distributions

Total cash distributions of $0.60 per unit were declared from September to December 2003. During the first quarter of 2004, the monthly cash distribution of $0.15 per unit is estimated to be within the Trust's target distribution range of between 60 percent and 70 percent of cash flow.

Off-Balance Sheet Arrangements and Contractual Obligations

The Trust uses various financial derivative instruments, the fair values of which are not reflected on the consolidated balance sheet, to reduce exposure to commodity and currency fluctuations. These risks, and the Trust's risk management policy, are discussed in "Risk and Risk Management." The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

The Trust has ongoing obligations related to abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Risk and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenue and cash flow depends on its success not only in developing its existing properties, but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural

Contractual Obligations

($ thousands)		Payments Due by Period			
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[1]	232,562	–	–	–	232,562
Operating leases	1,660	1,328	332	–	–
Transportation agreements	7,295	3,192	3,299	804	–
Total contractual obligations	241,517	4,520	3,631	804	232,562

(1) Total US $179.9 million

gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Evaluation Committee, consisting of qualified members of the Company's Board, of the Board of Directors assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserve estimates. Any future significant reserve revisions could result in a full-cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business can be managed with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program. The Trust recognizes gains or losses on financial derivative contracts as oil and natural gas production revenue when the associated production occurs.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices generally denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar denominated long-term debt. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on the lenders' prime lending rate and short-term Bankers' Acceptance rates.

The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

Oil And Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. Unit-of-production calculations are also used in the determination of the site restoration expense. By their inclusion in the unit-of-production calculation, reserve estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation and site restoration expense.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The ceiling test calculation utilizes and holds constant the prices and costs in effect at the end of the period. An estimate is made of the ultimate recoverable amount from future net revenue using proved reserves and period end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. The calculation of future net revenue in the ceiling test can be significantly impacted by fluctuations in any of these estimates. An impairment loss is recognized if the amount calculated under the ceiling test is less than the carrying costs of the Trust's petroleum and natural gas assets and can result in a significant accounting loss for a particular period.

New Accounting Pronouncements

In November 2002, the Canadian Institute of Chartered Accountants ("CICA") amended its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective to continue accrual accounting for positions hedged with derivatives. The new guideline is effective for fiscal years beginning on or after July 1, 2003. The Trust is evaluating the impact that the adoption of AcG-13 will have on its results of operations.

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 is required to 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 as compensation expense 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. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed in note 10 of the consolidated financial statements.

In March 2003, the CICA issued Section 3110, "Asset Retirement Obligations." This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The new standard is effective for all fiscal years beginning on or after January 1, 2004. The impact of adoption of this standard is estimated to be an increase in asset retirement obligation on the balance sheet of $33 million at December 31, 2003.

In February 2003, the CICA issued Accounting Guideline 14, "Disclosure of Guarantees" ("AcG-14"). AcG-14 establishes the disclosures required for obligations under certain guarantees. The disclosure requirements are effective for interim and annual periods beginning on or after January 1, 2003 and have been made in note 16 of the consolidated financial statements.

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

On November 10, 2003, the CICA issued a draft EIC (D37) on "Income Trusts - Exchangeable Units." The EIC proposes that the retained interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from unitholder's equity. This draft EIC is currently under review and was not enacted in final form as of the time of release of the Trust's 2003 consolidated financial statements.

In June 2003, the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities," which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the consolidated financial statements of the Trust.

FOURTH QUARTER 2003

The following discussion reviews the Trust's results of operations for the fourth quarter of 2003.

Total production for the fourth quarter of 2003 decreased nine percent to 36,195 boe per day from 39,890 boe per day for the same period in 2002, due to the sale of properties in March 2003 in the Ferrier area and the transfer of properties to Crew in September 2003. Petroleum and natural gas sales decreased 23 percent to $77.9 million for the fourth quarter of 2003 from $100.6 million for the fourth quarter of 2002. Total royalties decreased 19 percent to $13.5 million for the fourth quarter of 2003 from $16.7 million for the same period in 2002. Operating expenses for the fourth quarter of 2003 increased 11 percent to $22.1 million from $19.8 million for the corresponding quarter in 2002. 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.

General and administrative 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 due to lower exploration activity since the effective date of the Plan of Arrangement.

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 of 2002.The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

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 in 2002.

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 of 2002. 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 revision in proved reserves under the new standards of disclosure for oil and gas activities, NI 51-101, as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

Net income for the fourth quarter of 2003 was $8.9 million compared to $12.8 million for the corresponding quarter of 2002. In 2003, increased depletion expense was offset by foreign exchange gains and a recovery of future income taxes.

Outstanding Unit Information

At of February 29, 2004, the Trust had 61,027,681 units and 3,530,506 exchangeable shares outstanding. The exchange ratio at February 29, 2004 was 1.07444 trust units per exchangeable share.

Selected Annual Financial Information

($ thousands, except per-unit amounts)	**2003**	2002	2001
Revenue	$ **351,404**	$ 365,860	$ 329,700
Net income (loss)	**38,138**	45,136	(137,107)
Per-unit basic	**0.69**	0.86	(2.77)
Per-unit diluted	**0.67**	0.85	(2.77)
Total assets	**959,136**	997,760	967,046
Total long-term financial liabilities	**232,562**	326,977	330,102
Cash distributions declared[1]	$ **0.60**	$ –	$ –

(1) Total unit distributions declared since September 2, 2003.

Overall production for 2003 was 36,686 boe per day which represented a six percent decrease from 39,214 boe per day in 2002. Average wellhead prices received during 2003 were $29.28 per boe compared to $26.14 during 2002. Production in 2001 was 43,488 boe per day. Average wellhead prices received in 2001 were $21.37 per boe. Total revenue for 2003 was $351.4 million compared to $365.9 million in 2002 and $329.7 million in 2001.

Due to wide heavy oil differentials at year-end 2001, the Trust incurred a $131.3 million ceiling test write-down (net of $103.2 million of future income taxes). This amount was recognized as additional depletion and depreciation for the year ended December 31, 2001.

The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from asset sales at the end of March 2003 and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

Quarterly Financial Information (unaudited)

				2003				2002
($ thousands, except per-unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**77,869**	**87,200**	**79,288**	**107,047**	100,590	94,633	91,507	79,130
Cash flow from operations	**30,179**	**19,975**	**33,372**	**54,707**	53,116	48,637	49,208	40,125
Per unit basic	**0.51**	**0.36**	**0.62**	**1.03**	0.69	0.93	0.95	0.77
Per unit diluted	**0.51**	**0.36**	**0.61**	**1.01**	0.67	0.91	0.93	0.76
Net income (loss)	**8,881**	**(45,516)**	**41,830**	**32,943**	12,791	3,687	21,354	7,304
Per unit basic	**0.15**	**(0.83)**	**0.78**	**0.62**	0.24	0.07	0.41	0.14
Per unit diluted	**0.15**	**(0.83)**	**0.76**	**0.61**	0.24	0.07	0.40	0.14
Production								
Light oil and NGLs (bbls/d)	**1,982**	**1,989**	**2,167**	**2,969**	2,909	2,999	2,904	3,818
Heavy oil (bbls/d)	**24,400**	**25,123**	**22,816**	**23,278**	25,009	23,504	24,498	22,838
Total oil and NGLs (bbls/d)	**26,382**	**27,112**	**24,983**	**26,247**	27,918	26,503	27,402	26,656
Natural gas (mmcf/d)	**58.9**	**61.8**	**57.5**	**74.0**	71.8	71.3	73.3	73.7
Barrels of oil equivalent (boe/d @ 6:1)	**36,195**	**37,412**	**34,574**	**38,580**	39,890	38,391	39,625	38,948
Average Prices								
WTI oil (US$/bbl)	**31.18**	**20.20**	**28.91**	**33.86**	28.15	28.27	26.25	21.64
Edmonton par oil ($/bbl)	**39.56**	**40.94**	**41.08**	**50.91**	42.81	44.02	40.40	33.51
BTE light oil ($/bbl)	**36.41**	**34.43**	**37.13**	**45.41**	37.67	37.36	34.53	27.58
BTE heavy oil ($/bbl)	**22.40**	**24.19**	**22.98**	**31.48**	26.09	31.03	26.64	21.58
BTE total oil ($/bbl)	**23.48**	**24.92**	**24.24**	**33.15**	37.30	31.75	27.47	22.44
BTE natural gas ($/mcf)	**5.37**	**5.62**	**6.05**	**7.02**	5.29	3.33	3.94	3.19
BTE oil equivalent ($/boe)	**25.90**	**27.36**	**27.63**	**36.14**	28.64	28.10	26.29	21.39