ENTERRA ENERGY TRUST
Form 20-F
April 27, 2004

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

[ ] Registration statement pursuant to Section 12(b) or 12(g) of the Securities Exchange Act of 1934.

or

[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

For the fiscal year ended December 31, 2003.

Or

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the transition period from ---------- to ---------- .

Commission file number 333-39826

ENTERRA ENERGY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Alberta, Canada

(Jurisdiction of Incorporation or Organization)

Suite 2600, 500 4th Avenue S.W.

Calgary, Alberta, Canada

T2P 2V6

(Address of Principal Executive Offices)

S

ecurities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Trust Units	Toronto Stock Exchange
	Nasdaq

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

Trust Units, without par value at December 31, 2003: 18,955,960

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark which financial statement item the registrant has elected to follow. Item 17 [ ] Item 18 [X]

PART I

ITEM 1. Identity of Directors, Senior Management and Advisors

Not applicable

ITEM 2. Offer Statistics and Expected Timetable

Not applicable

ITEM 3. Key Information

A. Selected Financial Data

SUMMARY CONSOLIDATED FINANCIAL DATA

The financial data set forth below as at December 31, 2003 and 2002 and for each of the years in the three-year period ended December 31, 2003 have been derived from our audited consolidated financial statements included in Item 18 of this Form 20-F. Financial data at December 31, 2001, 2000 and 1999 and for each of the years in the three-year period ended December 31, 2000 have been derived from our previously published audited consolidated financial statements not included in this document.

The financial data as at December 31, 2003 and 2002 and for each of the years in the three-year period ended December 31, 2003 should be read in conjunction with, and are qualified in their entirety by reference to, our audited consolidated financial statements.

The financial data is derived from our financial statements which have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), the application of which, in the case of Enterra Energy Trust, conforms in all material respects for the periods presented with US GAAP, except as disclosed in footnotes to the financial statements.

The following table presents a summary of our consolidated statement of operations derived from our financial statements for 2003, 2002, 2001, 2000 and 1999. The monetary amounts in the table are based on Canadian generally accepted accounting principles ("Canadian GAAP"). All data presented below should be read in conjunction with the "Management s Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements and accompanying notes included elsewhere in this Form 20-F.

Consolidated statements of operations data:

(In thousand s, except per unit data)

	2003	2002	2001	2000	1999
	C$	C$	C$	C$	C$
Amounts in accordance with Canadian GAAP					
Revenue	$ 72,097	$ 25,746	$ 20,264	$ 16,700	$ 2,515
Earnings (loss) from operations	$ 12,835	$ 2,909	$ 3,228	$ 4,175	($ 409)
Net earnings (loss) for the year	$ 5,004	$ 4,977	$ 1,617	$ 2,453	($ 249)
Basic earnings (loss) per unit/share	$ 0.26	$ 0.27	$ 0.12	$ 0.28	($0.05)
Diluted earnings (loss) per unit/share	$ 0.26	$ 0.27	$ 0.12	$ 0.27	($0.05)
Amounts in accordance with US GAAP					
Revenue	$ 72,097	$ 25,746	$ 20,264	$ 16,700	$ 2,515
Earnings (loss) from operations	$ 18,016	$ 5,969	($24,797)	$ 4,175	($ 409)
Net earnings (loss) for the year	$ 6,510	$ 6,748	($ 15,534)	$ 2,628	($ 328
Basic earnings (loss) per unit/share	$ 0.34	$ 0.37	($ 1.11)	$ 0.27	($0.07)
Diluted earnings (loss) per unit/share	$ 0.34	$ 0.36	($ 1.11)	$ 0.26	($0.07)

-2-

The following table indicates a summary of our consolidated balance sheets as of December 31, 2003, 2002, 2001, 2000 and 1999. The monetary amounts in the table are based on Canadian GAAP.

Consolidated balance sheet data:

(In Thousand s) As at December 31

	2003	2002	2001	2000	1999
	C$	C$	C$	C$	C$
Amounts in accordance with Canadian GAAP					
Cash	$ 66	$ 108	$ 43	$ 1	$ 42
Accounts receivable and prepaids	11,219	7,971	6,880	2,505	685
Capital assets	104,821	94,354	73,139	18,335	7,017
Total assets	116,230	102,717	80,063	22,101	7,744
Total stockholders equity	47,781	38,663	33,524	7,371	3,978
Dividends paid on preferred shares	$33	$23	-	-	-
Dividends paid on common shares	-	-	-	-	-
Amounts in accordance with US GAAP					
Cash	$ 66	$ 108	$ 43	$ 1	$ 42
Accounts receivable and prepaids	11,219	7,971	6,880	2,505	685
Capital assets	84,288	68,308	43,693	18,085	6,835
Total assets	95,696	76,670	50,616	22,076	7,562
Total unitholders equity	33,997	23,373	16,373	7,545	3,978
Dividends paid on preferred shares	$33	$23	-	-	-
Dividends paid on common shares	-	-	-	-	-

Exchange Rate Information

We publish our consolidated financial statements in Canadian dollars. In this prospectus, except where otherwise indicated, all dollar amounts are stated in Canadian dollars. References to "$" or "Cdn.$" are to Canadian dollars and references to "US$" are to U.S. dollars. The following table sets forth for each period indicated the period end exchange rates for conversion of U.S. dollars to Canadian dollars, the average exchange rates on the last day of each month during such period and the high and low exchange rates during such period. These rates are based on the noon buying rate in New York City, expressed in U.S. dollars, for cable transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York. The exchange rates are presented as Canadian dollars per $1.00. On March 31, 2004, the noon buying rate was US$1.00 equals Cdn.$ 1.3081and the inverse noon buying rate was Cdn.$1.00 equals US$0.7648.

U.S. Dollar/Canadian Dollar Exchange Rates for Five Most Recent Financial Years

Year Ended December 31,	**2003**	**2002**	**2001**	**2000**	**1999**

End of period	0.7738	0.6344	0.6285	0.6669	0.6918
Average for the period	0.7139	0.6372	0.6456	0.6732	0.6691
High during the period	0.7738	0.6656	0.6714	0.6969	0.6935
Low during the period	0.6349	0.6175	0.6227	0.6410	0.6464

U.S. Dollar/Canadian Exchange Rates for Previous Six Months

	October 2003	**November 2003**	**December 2003**	**January 2004**	**February 2004**	**March 2004**
High	0.7680	0.7731	0.7747	0.7883	0.7650	0.7659
Low	0.7371	0.7440	0.7447	0.7481	0.7398	0.7357

-3-

B. Capitalization and Indebtedness

Not Applicable

C. Reasons for the Offer and Use of Proceeds

Not Applicable

D. Risk Factors

Set out below are certain risk factors that could materially adversely affect our cash flow, operating results, financial condition or the business of our operating subsidiaries. Investors should carefully consider these risk factors before making investment decisions involving our trust units.

Our results of operations and financial condition are dependent on the prices received for our oil and natural gas production.

Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in crude oil or natural gas prices may have a material adverse effect on our operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of oil and natural gas reserves. Any resulting decline in our cash flow could reduce distributions.

We use financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from changes in natural gas and oil commodity prices. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, our commodity hedging activities could expose us to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect or our hedging policies and procedures are not followed. Furthermore, we cannot guarantee that such hedging transactions will fully offset the risks of changes in commodities prices.

In addition, we regularly assess the carrying value of our assets in accordance with Canadian generally accepted accounting principles under the full cost method. If oil and natural gas prices become depressed or decline, the carrying value of our assets could be subject to downward revision.

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce distributions to unitholders as well as affect the market price of the trust units.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by the Trust and, therefore, may reduce distributions to our unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in our production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to unitholders.

Distributions may be reduced during periods in which we make capital expenditures or debt repayments using cash flow, which could also affect the market price of our trust units.

To the extent that we use cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow that the Trust receives that is available for distribution to unitholders will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Trust and, as a consequence, the amount of cash available to distribute to unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

-4-

The board of directors of Enterra has the discretion to determine the extent to which cash flow from Enterra will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the credit facility. Funds used for such purposes will not be payable to the Trust. As a consequence, the amount of funds retained by Enterra to pay debt service charges or reduce debt will reduce the amount of cash available for distribution to unitholders during those periods in which funds are so retained.

A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the price that we received for our production which, in turn, could reduce distributions to unitholders as well as affect the market price of our trust units.

Our business depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could reduce distributions to our unitholders.

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our trust units as well as distributions to unitholders.

The price that we receive for a majority of our oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price. We could be subject to unfavourable price changes to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

If we are unable to acquire additional reserves, the value of our trust units and distributions to unitholders may decline.

We do not actively explore for oil and natural gas reserves. Instead, we add to our oil and natural gas reserves primarily through development, exploitation and acquisitions. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We also distribute the majority of our net cash flow to unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional trust units, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of our trust units and in a reduction in cash available for distributions to unitholders.

Actual reserves will vary from reserve estimates, and those variations could be material, and affect the market price of our trust units and distributions to unitholders.

The reserve and recovery information contained in the independent engineering report prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") relating to Enterra's 2003 reserves is only an estimate and the actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by McDaniel.

The value of our trust units depends upon, among other things, the reserves attributable to our properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The reserve figures contained herein are only estimates. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;
- marketability of production;
- effects of government regulation; and
- other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates.

If we expand our operations beyond oil and natural gas production in western Canada, we may face new challenges and risks.

If we were unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected, which could affect the market price of our trust units and distributions to unitholders.

Our operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present challenges and risks that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

In determining the purchase price of acquisitions, we rely on both internal and external assessments relating to estimates of reserves that may prove to be materially inaccurate. Such reliance could adversely affect the market price of our trust units and distributions to unitholders.

The price we are willing to pay for reserve acquisitions is based largely on estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves we acquire may be less than expected, which could adversely impact cash flows and distributions to unitholders. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

Some of our properties are not operated by us and, therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of our trust units and distributions to unitholders.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At December 31, 2003, approximately % of our daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, our revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements which govern the properties not operated by us typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners, such as unitholders, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or wilful misconduct.

Delays in business operations could adversely affect distributions to unitholders and the market price of our trust units.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;

- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to unitholders in a given period and expose us to additional third party credit risks.

We may, from time to time, finance a significant portion of our operations through debt. Our indebtedness may limit the timing or amount of the distributions that are paid to unitholders, and could affect the market price of our trust units.

The payments of interest and principal, and other costs, expenses and disbursements to our lenders reduces amounts available for distribution to unitholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the unitholders. The agreements governing our credit facility provide that if we are in default under the credit facility, exceed certain borrowing thresholds or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to make distributions to unitholders may be restricted.

Our lenders have been provided with a security interest in substantially all of our assets. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may foreclose on and sell the properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to unitholders.

Our current credit facility and any replacement credit facility may not provide sufficient liquidity.

The amounts available under our existing credit facility may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. Our current credit facility consists of a revolving operating demand loan. Repayment of all outstanding amounts may be demanded at any time. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and distributions to unitholders may be materially reduced.

We have a working capital deficiency at December 31, 2003; our credit facilities can be called at any time. Any material change in our liquidity could impair our ability to pay dividends and could adversely affect the value of your investment.

Our credit facilities are classified as a short-term liability on our balance sheet as they are on a demand basis and may be called at any time. Accordingly, at December 31, 2003, we had a working capital deficiency of $ 38.2 million, which means our current liabilities exceeded our current assets by that amount. Although we are not subject to and do not expect to make principal repayments under our current banking arrangement, they could be called for repayment at any time. Other than in the event of a default or a breach of covenants, we do not expect to make any principal payments in 2004.

Our assets are highly leveraged. Any material change in our liquidity could impair our ability to pay dividends and could adversely affect the value of your investment.

We carry a high amount of debt relative to our assets. A decrease in the amount of our production or the price we receive for it could make it difficult for us to service our debt or may cause the bank that issued our loan to determine that our assets are insufficient security for our bank debt.

The oil and natural gas industry is highly competitive.

We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our trust units and distributions to unitholders.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance.

Our operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. A number of these risks could result in personal injury, loss of life, or environmental and other damage to our property or the property of others. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to unitholders.

The operation of oil and natural gas wells could subject us to environmental claims and liability.

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating the oil and natural gas industry may be changed to impose higher standards and potentially more costly obligations. For example, the 1997 Kyoto Protocol to the United Nation's Framework Convention on Climate Change, known as the Kyoto Protocol, was ratified by the Canadian government in December, 2002 and will require, among other things, significant reductions in greenhouse gases. The impact of the Kyoto Protocol on us is uncertain and may result in significant additional costs (future) for our operations. Although we record a provision in our financial statements relating to our estimated future environmental and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future environmental and reclamation obligations.

We are not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, our properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of cash flow and, therefore, will reduce the amounts available for distribution to unitholders. Should we be unable to fully fund the cost of remedying an environmental problem, we might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Lower crude oil and natural gas prices increase the risk of ceiling limitation write-downs. Any write-downs could materially affect the value of your investment.

We changed our method of accounting for petroleum and natural gas properties from the "successful efforts" method to the "full cost" method in 2001. All costs related to the exploration for and the development of oil and gas reserves are capitalized into a single cost centre representing Enterra s activity which is undertaken exclusively in Canada. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells. Proceeds from the disposal of properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a major change in the depletion rate.

-8-

Capitalized costs are depleted and depreciated using the unit-of-production method based on the estimated gross proven oil and natural gas reserves before royalties as determined by independent engineers. Units of natural gas are converted into barrels of equivalents on a relative energy content basis. Capitalized costs, net of accumulated depletion and depreciation, are limited to estimated future net revenues from proven reserves, based on year-end prices, undiscounted, less estimated future abandonment and site restoration costs, general and administrative expenses, financing costs and income taxes. Estimated future abandonment and site restoration costs are provided for over the life of proven reserves on a unit-of-production basis. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration costs are charged to the provision as incurred. The amounts recorded for depletion and depreciation and the provision for future abandonment and site restoration costs are based on estimates of proven reserves and future costs. The recoverable value of capital assets is based on a number of factors including the estimated proven reserves and future costs. By their nature, these estimates are subject to measurement uncertainty and the impact on financial statements of future periods could be material.

We perform a cost recovery ceiling test which limits net capitalized costs to the undiscounted estimated future net revenue from proven oil and gas reserves plus the cost of unproven properties less impairment, using year-end prices or average prices in that year, if appropriate. In addition, the value is further limited by including financing costs, administration expenses, future abandonment and site restoration costs and income taxes. Under U.S. GAAP, companies using the "full cost" method of accounting for oil and gas producing activities perform a ceiling test using discounted estimated future net revenue from proven oil and gas reserves using a discount factor of 10%. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001 Enterra realized a U.S. GAAP ceiling test write-down of Cdn.$17,500,000, after tax. There were no such write-down required at December 31, 2002 or 2003.

The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are low or volatile. We may experience additional ceiling test write-downs in the future.

Unforeseen title defects may result in a loss of entitlement to production and reserves.

Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized and, as a result, distributions to unitholders may be reduced.

Aboriginal Land Claims

The economic impact on us of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal title and rights to a substantial portion of western Canada. We are unable to assess the effect, if any, that any such claim would have on our business and operations.

Changes in tax and other laws may adversely affect unitholders.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Trust and unitholders. Tax authorities having jurisdiction over the Trust or the unitholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of unitholders. The Department of Finance (Canada) has indicated that it will continue to evaluate the development of the income trust market as part of its ongoing monitoring and assessment of Canadian financial markets and the Canadian tax system. Accordingly, changes in this area are possible.

Income Tax Matters

On October 31, 2003, the Department of Finance (Canada) released, for public comment, proposed amendments to the Tax Act that relate to the deductibility of interest and other expenses for income tax purposes for taxation years commencing after 2004. In general, the proposed amendments may deny the realization of losses in respect of a business if there is no reasonable expectation that the business will produce a cumulative profit over the period that the business can reasonably be expected to be carried on. If such proposed amendments were enacted and successfully invoked by the CCRA against the Trust or a subsidiary entity, it could materially adversely affect the amount of distributable cash available. However, Enterra believes that it is reasonable to expect the Trust and each subsidiary entity to produce a cumulative profit over the expected period that the business will be carried on.

-9-

Expenses incurred by Enterra are only deductible to the extent they are reasonable. Although the Trust is of the view that all expenses to be claimed by the Trust and its subsidiary entities should be reasonable and deductible, there can be no assurance that CCRA will agree. If CCRA were to successfully challenge the deductibility of such expenses, the return to unitholders may be adversely affected.

The Trust Indenture provides that an amount equal to the taxable income of the Trust will be payable each year to unitholders in order to reduce the Trust s taxable income to zero. Where in a particular year, the Trust does not have sufficient available cash to distribute such an amount to unitholders, the Trust Indenture provides that additional trust units must be distributed to unitholders in lieu of cash payments. unitholders will generally be required to include an amount equal to the fair market value of those trust units in their taxable income, notwithstanding that they do not directly receive a cash payment.

As noted above, the Department of Finance (Canada) has indicated that it will continue to evaluate the development of the income trust market as part of its ongoing monitoring and assessment of Canadian financial markets and the Canadian tax system. Accordingly, changes in this area are possible. Such changes could result in the income tax considerations described under the heading "Canadian Federal Income Tax Considerations" being materially different in certain respects.

There would be material adverse tax consequences if the Trust lost its status as a mutual fund trust under Canadian tax laws.

It is intended that the Trust continue to qualify as a mutual fund trust for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- ♦ The Trust would be taxed on certain types of income distributed to unitholders, including income generated by the royalties held by the Trust. Payment of this tax may have adverse consequences for some unitholders, particularly unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.
- ♦ The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.
- ♦ Trust units held by unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of trust units held by them.
- ♦ The trust units would not constitute qualified investments for Registered Retirement Savings Plans, or "RRSPs", Registered Retirement Income Funds, or "RRIFs", Registered Education Savings Plans, or "RESPs", or Deferred Profit Sharing Plans, or "DPSPs". If, at the end of any month, one of these exempt plans holds trust units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the trust units at the time the trust units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified trust units would be subject to taxation on income attributable to the trust units. If an RESP holds non-qualified trust units, it may have its registration revoked by the Canada Customs and Revenue Agency.

In addition, we may take certain measures in the future to the extent we believe them necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of trust units.

Rights as a unitholder differ from those associated with other types of investments.

The trust units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Trust or Enterra. The trust units represent an equal fractional beneficial interest in the Trust and, as such, the ownership of the trust units does not provide unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring "oppression" or "derivative" actions. The unavailability of these statutory rights may also reduce the ability of unitholders to seek legal remedies against other parties on our behalf.

The trust units are also unlike conventional debt instruments in that there is no principal amount owing to unitholders. The trust units will have minimal value when reserves from our properties can no longer be economically produced or marketed. unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment and the distributions received over the life of the investment may not meet or exceed the initial capital investment.

-10-

Changes in market-based factors may adversely affect the trading price of our trust units.

The market price of our trust units is primarily a function of anticipated distributions to unitholders and the value of our properties. The market price of our trust units is therefore sensitive to a variety of market based factors, including, but not limited to, interest rates and the comparability of our trust units to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the trust units.

Our operations are entirely independent from the unitholders and loss of key management and other personnel could impact our business.

Unitholders are entirely dependent on the management of Enterra with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to our oil and natural gas properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Trust. Investors should carefully consider whether they are willing to rely on the existing management before investing in the trust units.

There may be future dilution.

One of our objectives is to continually add to our reserves through acquisitions and through development. Since we do not reinvest a material portion of our cash flow, our success is, in part, dependent on our ability to raise capital from time to time by selling additional trust units. unitholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of trust units issued to acquire those assets. unitholders may also suffer dilution in connection with future issuances of trust units to effect acquisitions.

There may not always be an active trading market for the trust units.

While there is currently an active trading market for our trust units in the United States and Canada, we cannot guarantee that an active trading market will be sustained.

The limited liability of unitholders is uncertain.

Due to uncertainties in the law relating to investment trusts, there is a risk that a unitholder could be held personally liable for obligations of the Trust in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. Although every written contract or commitment of the Trust must contain an express disavowal of liability of the unitholders and a limitation of liability to Trust property, such protective provisions may not operate to avoid unitholder liability. Notwithstanding attempts to limit unitholder liability, unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although the Trust has agreed to indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by the unitholder resulting from or arising out of that unitholder not having limited liability, the Trust cannot guarantee that any assets would be available in these circumstances to reimburse unitholders for any such liability.

The redemption rights of unitholders is limited.

Unitholders have a limited right to require the Trust to repurchase their trust units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for unitholders to liquidate their investment. The Trust's ability to pay cash in connection with a redemption is subject to limitations. Any securities which may be distributed in specie to unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

-11-

Taxation of Enterra

Enterra is subject to taxation in each taxation year on its income for the year, after deducting interest paid to the Trust on the Note and after deducting payments, if any, made to the Trust with respect to the Royalty Agreement. During the period that Exchangeable Shares issued by Enterra are outstanding, a portion of the cash flow from operations will be subject to tax to the extent that there are not sufficient resource pool deductions, capital cost allowance or utilization of prior years non-capital losses to reduce taxable income to zero. Enterra intends to deduct, in computing its income for tax purposes, the full amount available for deduction in each year associated with its income tax resource pools, undepreciated capital cost ("UCC") and non-capital losses, if any. If there are not sufficient resource pools, UCC and non-capital losses carried forward to shelter the income of Enterra, then cash taxes would be payable by Enterra. In addition, there can be no assurance that taxation authorities will not seek to challenge the amount of interest expense relating to the Note. If such a challenge were to succeed against Enterra, it could materially adversely affect the amount of cash flow available for distribution to unitholders.

Further, interest on the Note accrues at the Trust level for income tax purposes whether or not actually paid. The Trust Indenture provides that an amount equal to the taxable income of the Trust will be distributed each year to unitholders in order to reduce the Trust's taxable income to zero. Where interest payments on the Notes are due but not paid in whole or in part, the Trust Indenture provides that any additional amount necessary to be distributed to unitholders may be distributed in the form of Units rather than in cash. unitholders will be required to include such additional amount in income even though they do not receive a cash distribution.

We may undertake acquisitions that could limit our ability to manage and maintain our business, result in adverse accounting treatment and are difficult to integrate into our business. Any of these events could result in a material change in our liquidity, impair our ability to pay dividends and could adversely affect the value of your investment.

A component of future growth will depend on the ability to identify, negotiate, and acquire additional companies and assets that complement or expand existing operations. However we may be unable to complete any acquisitions, or any acquisitions we may complete may not enhance our business. Any acquisitions could subject us to a number of risks, including:

- diversion of management's attention;
- inability to retain the management, key personnel and other employees of the acquired business;
- inability to establish uniform standards, controls, procedures and policies;
- inability to retain the acquired company's customers;
- exposure to legal claims for activities of the acquired business prior to acquisition; and inability to integrate the acquired company and its employees into our organization effectively.

Since we are a Canadian company and most of our assets and key personnel are located in Canada, you may not be able to enforce a U.S. judgment for claims you may bring against us, our assets, our key personnel or many of the experts named in this prospectus. This may prevent you from receiving compensation to which you would otherwise be entitled.

We have been organized under the laws of Alberta, Canada and all of our assets are located outside the U.S. In addition, a majority of the members of our Board of Directors and our officers and many of the experts named in this prospectus are residents of countries other than the U.S. As a result, it may be impossible for you to effect service of process upon us or these individuals within the U.S. or to enforce any judgments in civil and commercial matters, including judgments under U.S. federal securities laws. In addition, a Canadian court may not permit you to bring an original action in Canada or to enforce in Canada a judgment of a U.S. court based upon civil liability provisions of the U.S. federal securities laws.

ITEM 4. Information on the Trust

BUSINESS

The Trust

Enterra Energy Trust (the "Trust", "Enterra" and, together with its direct and indirect subsidiaries and partnerships, "we", "our" or "us") is an open ended unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture dated as of October 24, 2003, between Enterra Energy Corp. and Olympia Trust Company (the "Trust Indenture"). Our head and principal office is located at 2600, 500 4th Avenue S.W., Calgary, Alberta, T2P 2V6.

As a result of the completion of a plan of arrangement involving the Trust, Enterra Energy Corp. ("Old Enterra"), Enterra Acquisition Corp. and Enterra Energy Commercial Trust ("EEC Trust") (the "Arrangement") on November 25, 2003, former holders of common shares of Enterra Corp. received two trust units or two Exchangeable Shares of Enterra Acquisition Corp., in accordance with the elections made by such holders, and Old Enterra becoming a subsidiary of the Trust. Old Enterra was subsequently amalgamated with Enterra Acquisition Corp. to form Enterra Energy Corp. ("New Enterra")

The principal undertaking of the Trust is to issue trust units and to acquire and hold debt instruments, royalties and other interests. The direct and indirect wholly owned subsidiaries of the Trust carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto.

We make monthly cash distributions to unitholders from our net cash flow. Our primary sources of cash flow are interest payments from New Enterra and EEC Trust on the principal amounts of the Note and the CT Note, respectively.

Olympia Trust Company has been appointed as trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the outstanding trust units. The principal and head office of Olympia Trust Company is located at 2300, 125 9th Avenue S.E., Calgary, Alberta T2G 0P6.

New Enterra

New Enterra is the principal operating subsidiary of the Trust. New Enterra was formed on the amalgamation of Enterra Acquisition Corp., Big Horn Resources Ltd., Enterra Sask. Ltd. and Enterra Energy Corp. on November 25, 2003 pursuant to the Arrangement and is governed by the laws of the Province of Alberta. EEC Trust is the sole holder of voting shares of New Enterra. All of the crude oil and natural gas properties and related assets in which the Trust has an interest are held, directly or indirectly, through New Enterra.

The Partnership

Enterra Production Partnership (the "Partnership") was formed as a general partnership under the laws of the Province of Alberta on August 16, 2001. The Partnership currently holds all of our producing crude oil and natural gas properties from which we ultimately derive our cash flow. The partners of the Partnership are New Enterra and Enterra Energy Partner Corp.

EEC Trust

Enterra Energy Commercial Trust is a commercial trust governed by the laws of the Province of Alberta. The Trust holds 100% of the issued and outstanding trust units of EEC Trust. EEC Trust 100% of the issued and outstanding common shares of New Enterra.

History

Old Enterra (formerly Westlinks Resources Ltd.) was organized on June 30, 1998 by the statutory amalgamation of Temba Resources Ltd. and PTR Resources Ltd. pursuant to the provisions of the *Business Corporations Act* (Alberta). Temba Resources Ltd. was incorporated in Alberta on July 31, 1996. Immediately prior to the amalgamation which created Old Enterra, Temba Resources Ltd. amalgamated with its wholly owned subsidiary, Rainee Resources Ltd. PTR Resources Ltd. was incorporated in Alberta on September 18, 1992 as 542275 Alberta Ltd., changed its name to Ablevest Holdings Ltd. on June 14, 1993, and to PTR Resources Ltd. on December 1, 1997.

I

n 1998, Old Enterra acquired a non-operated working interest averaging approximately 20% in a Dina sand pool located in the Sounding Lake area of Alberta, consisting of 1,270 acres and approximately 35 producing wells.

-13-

In September 1999, Old Enterra acquired a 94% working interest in four producing oil wells and a saltwater disposal well in the Sylvan Lake area of Alberta.

In May 2000, Old Enterra acquired, effective January 1, 2000, further working interests in the Sounding Lake area of Alberta, consisting of a further 36% working interest in the Dina sand pool as well as working interests averaging approximately 91% in 21 producing oil wells. The purchase price for such interests was $11,900,000.

On November 15, 2000, Old Enterra sold, effective October 1, 2000, all of its interests in the Bigoray area of Alberta for cash consideration of $4,494,500. Proceeds from the sale were used to reduce Old Enterra's bank debt and to fund its 2001 acquisition program.

On December 6, 2000, Old Enterra acquired a 25% working interest in a producing gas well in the Altares area of northeast British Columbia for cash consideration of $1,000,000.

On January 17, 2001, Old Enterra completed a secondary public offering in the United States of 1,000,000 units, each unit consisting of one common share and one share purchase warrant, for U.S. $4.55 per unit. The share purchase warrants were exercisable for six months at U.S. $4.50 per share. Net proceeds from the offering were used for Old Enterra's 2001 acquisition and drilling program.

On February 28, 2001, Old Enterra entered into a farm-out and option agreement whereby it was granted to ability to earn an interest in over 12,000 acres of land in the Altares region of northeast British Columbia. Under the terms of the farm-out and option agreement, Old Enterra was obligated to drill a minimum of two wells and had an option to drill up to four more wells to earn an interest in all of the lands.

On March 27, 2001, Old Enterra acquired an average 67% working interest in 8,705 gross acres of land and 34 producing oil wells in the Grand Forks area of southern Alberta for cash consideration of $5,500,000. The effective date of the acquisition was January 1, 2001.

On April 23, 2001, Old Enterra entered into the EuroGas Agreement. On June 5, 2001, Old Enterra completed the acquisition of an aggregate of 8,275,500 Big Horn shares from EuroGas.

On June 12, 2001, Old Enterra entered into an agreement with a private company to acquire certain oil and gas assets in the Superb area of Saskatchewan. The purchase price fort the assets was $2,800,000, which amount was satisfied by the payment of $1,500,000 in cash and through the issuance of Common Shares. Through this acquisition, Old Enterra acquired a 91% working interest in four existing Waseca heavy oil wells with a combined production rate of approximately 180 Bbls/d.

Effective August 16, 2001, Westlinks and Big Horn Resources Ltd. entered into an agreement under Section 192 of the *Canada Business Corporations Act*, whereby Big Horn shareholders were issued Westlinks common shares and options in exchange for Big Horn common shares and options. Big Horn was incorporated under the laws of the Province of Saskatchewan on February 16, 1960 as Contact Gold Mines Ltd. On July 7, 1969, Big Horn changed its name to Contact Ventures Ltd. Big Horn was continued under the *Business Corporations Act* (Saskatchewan) on December 28, 1979 and subsequently continued under the *Canada Business Corporations Act* on September 9, 1982. On April 15, 1988, Big Horn changed its name to West Pride Industries Corp. and on April 2, 1991 Big Horn consolidated its common shares on a 4 for 1 basis. Effective September 7, 1993 Big Horn further consolidated its common shares on a 7 for 1 basis and changed its name to Big Horn Resources Ltd.

Effective December 10, 2001, Westlinks Resources Ltd. (i.e., Old Enterra) changed its name to Enterra Energy Corp.

On March 26, 2002, Old Enterra redeemed 6,123,870 of its Series I Preferred Shares for $2,300,000, resulting in a gain of $2,905,290.

On April 12, 2002, Old Enterra was granted a 30-day extension for the 1,000,000 share purchase warrants which were exercisable until April 17, 2002. The expiry date was extended to May 17, 2002. The warrants expired on May 17, 2002 without being exercised.

On October 8, 2002, Old Enterra raised $5 million for a sale-leaseback arrangement on some of its production equipment.

-14-

On October 8, 2002, Old Enterra purchased 3,300 acres of land in one of its core areas for $2.5 million.

Old Enterra received $18.3 million in 2003 as proceeds on the sale of miscellaneous non-core properties. These proceeds were applied to reduce bank debt and improve working capital.

On June 20, 2003, Old Enterra s common shares commenced trading on the Toronto Stock exchange under the symbol "ENT". They were previously trading on the TSX Venture Exchange.

On August 5, 2003 Old Enterra announced its intention to reorganize itself into an oil and gas income trust.

On September 30, 2003, Old Enterra redeemed all 611,803 outstanding Series I Preferred Shares for $520,032.

On October 27, 2003 The American Stock Exchange began trading in options in Old Enterra under the symbol "EMU".

Old Enterra s plan of arrangement in respect of the reorganization of Old Enterra into Enterra Energy Trust received overwhelming approval at the special shareholder meeting held on November 24, 2003. Shareholders voted 99.37% in favor of the arrangement resolution. The transaction also received the approval of the Court of Queen s Bench of Alberta on November 24, 2003. The transaction became effective on November 25, 2003. The trust units of Enterra Energy Trust commenced trading on the Nasdaq under "EENC" and the Toronto Stock Exchange under "ENT.un" on Friday November 28, 2003. After the transaction, the Trust had a total of 18,951,556 trust units issued and outstanding. In addition, New Enterra had a total of 2,000,000 exchangeable shares issued and outstanding.

The registered office of the Corporation is located at Suite 3300, 421 7th Avenue S.W., Calgary, Alberta, T2P 4K9 and its head office is located at Suite 2600, 500-4th Avenue S.W., Calgary, Alberta T2P 2V6.

Our business

Enterra operates in Canada as an oil and gas income trust. Our current production is approximately 6,500 to 7,000 BOE/D and our established reserves (including the January 2004 purchase of properties in East Central Alberta) are approximately 12 MBOE. We pays a monthly distribution to its unitholders. This amount was set at US$0.10 for the first three distributions and was recently increased to US$0.11 for the March 2004 distribution (which is to be paid on April 15, 2004). Our growth will come mainly from future acquisition of properties to replenish our reserves. These acquisitions will be financed in part with additional debt and with the issuance of trust units.

Business Strategy

Enterra s business strategy is to grow its reserves and distributions by acquiring properties which provide additional production and potential for development upside. Enterra is focused on per unit growth. We will finance acquisitions with both debt and equity, the optimal mix being one which minimizes unitholders dilution while maintaining a strong balance sheet. Enterra s ability to replace and grow its reserves over time is the key success factor in our business strategy.

Properties

Enterra's core areas included the Peace River Arch area of Alberta, Central Alberta and East Central Alberta. Enterra also has a large inventory of prospects, the development of which could significantly increase the size of Enterra s existing production and reserve base.

Peace River Arch of Alberta

Clair

The Clair property is located 13 km north of the city of Grande Prairie, Alberta. Enterra s assets include a 100% working interest in 3,840 acres of land, 20 producing oil wells and an oil treating facility. Gas is conserved and processed at the Encana Sexsmith gas plant.

Production is primarily from the Doe Creek (Dunvegan) formation with a small amount of gas production from the Charlie Lake and Halfway. Production is light, 44 degree API gravity crude and solution gas is produced from the Doe Creek oil pool. At December 31, 2003 there were 20 oil wells producing a combined 2,175 bbl/d of oil and 2.1 mmcf/d of solution gas. One dually completed Charlie Lake and Halfway gas well also produces combined daily gas of 400 mcf/d. Enterra has a 100% working interest in this well. To date, Enterra has drilled or recompleted 29 wells for oil and seven wells for water injection. There are no further drilling plans for the pool. Enterra has received waterflood approval in June 2003 (with two recent amendment approvals) and is in the final stages of achieving 100% voidage replacement pending minor waterflood modifications. Nine wells shut-in in 2003 due to excessive gas production will be reactivated once pressure support from the waterflood is received at the wells.

Total proved reserves assigned to the Doe Creek A (Dunvegan) pool are 1,997 mbbl of oil, 1,236 mmcf of gas and 38 mbbl of natural gas liquids. Total proved and probable reserves assigned to the Doe Creek A (Dunvegan) pool are

2,998 mbbl of oil, 1,633 mmcf of gas and 51 mbbl of natural gas liquids. The probable reserves category contains the incremental reserves and net present value of the waterflood. McDaniel and Associates have stated that the additional reserves associated with the waterflood would be moved into the proven category in a staged approach. Critical stages include the achievement of 100% voidage replacement and continued performance. Total proved reserves assigned to the 13-07-073-5W6 Charlie Lake / Halfway gas well are 256 mmcf of gas and 8 mbbl of natural gas liquids. Total proved and probable reserves assigned to the Charlie Lake / Halfway gas well are 368 mmcf of gas and 11 mbbl of natural gas liquids.

Enterra also owns and operates a central oil treating facility at Clair which was connected into the Pembina Peace Pipeline system in September 2003.

Gordondale

The Gordondale property is located 75 km northwest of the city of Grande Prairie, Alberta. Enterra s assets included an average working interest of 79% in 6,240 gross acres of land as well as two flowing gas wells, one gas well awaiting tie in and one oil well. Production is currently from the Upper Kiskatinaw and Halfway zones. Enterra s share of production for the property was 300 mcf/d of gas, 8 bbl/d of oil and 4 bbl/d of natural gas liquids. The property was sold in December 2003.

McDaniel and Associates had assigned Company s share of total proved reserves to Gordondale of 164 mmcf of gas, 2 mbbl of oil, and 2 mbbl of natural liquids. Total proved and probable reserves were 217 mmcf of gas, 3 mbbl of oil, and 3 mbbl of natural gas liquids.

Rolla

The Rolla property is located 70 km north of the city of Grande Prairie, Alberta. Enterra s assets include a 50% working interest in 1,920 acres of land, 3 operated producing gas wells and a 12.5% working interest in two field compressors. Enterra s share of current gas production is approximately 800 mcf/d from three 50% working interest Dunvegan gas wells. This gas is processed at the Duke Midstream, Gordondale East gas plant.

Total proved reserves assigned to the Dunvegan are 512 mmcf of gas, and total proved and probable reserves assigned to the Dunvegan are 725 mmcf of gas. All of the proved reserves are in the proved producing category. The Dunvegan sand development in the Rolla area is part of a large Delta complex from the northwest.

Hines Creek

The Hines Creek property is located 150 km north of the city of Grande Prairie, Alberta. Enterra s assets include a 50% working interest in 5,760 acres of land, one producing gas well and one shut-in gas well currently awaiting a fracture stimulation. Enterra s share of current gas production is approximately 850 mcf/d from the 50% working interest well, and expects Enterra s share of production from the 50% working interest shut-in well to be in excess of 200 mcf/d.

Total proved reserves assigned to the Hines Creek property are 728 mmcf of gas, and total proved and probable reserves are 882 mmcf of gas. All of the proved reserves are in the proved producing category.

East Central Alberta

Sounding Lake

The Sounding Lake package is located 10 km southwest of the town of Provost, Alberta. Enterra s assets include an average working interest of 58.7% in 5,496 gross acres of land as well as 56 producing oil wells and 2 producing gas wells. Production is obtained primarily from the Dina, Cummings and Belly River formations. The three main oil pools are Sounding Lake West, Sounding Lake East, and Sounding Lake North. Enterra s share of current production for the entire area is 520 bbl/d of oil and 1,700 mcf/d of gas. Enterra has and continues to upgrade pump sizes to maximize oil production and upgrade oil batteries to handle higher volumes of total fluid and injection water. Enterra has also tied-in the flared solution gas from two of its key facilities in the area.

Enterra was assigned proved reserves at Sounding Lake of 741 mbbl of oil and 1,451 mmcf of natural gas. Total proved and probable reserves are 926 mbbl oil and 1,870 mmcf natural gas based on improved performance from the existing wells.

-16-

Central Alberta

Sylvan Lake

The Sylvan Lake property is located 40 km west of the town of Red Deer, Alberta. Enterra s assets include an average working interest of 74.8% in 4,320 gross acres of land as well as 24 producing oil wells and 1 producing gas well. Enterra completed the development of 40-acre spacing wells in the Pekisko G pool, increasing the number of producing wells from five to 24 wells. The property currently produces 1,225 bbl/d (gross), 1,100 bbl/day (net) of 14 degree API oil from 24 wells with 850 mcf/d (net) of associated gas plus an additional 30 mcf/d (net) of non-associated gas. Production is flowlined into a central treating facility constructed in September 2003 which is owned and operated by Enterra Energy. Non-associated gas is conserved and flowlined to the Husky Sylvan Lake gas plant. Clean oil is trucked from the facility to sales.

McDaniel and Associates has assigned total proved reserves of 1,814 mbbl of oil, 1,014 mmcf of solution gas, and 32 mmcf of non-associated gas to this property. Total proved and probable reserves are 2,404 mbbl of oil, 1,344 mmcf of solution gas, and 40 mmcf of non-associated gas. Probable reserves were assigned based on an assumption that the wells will achieve a slightly higher oil recovery than estimated. Based on the success of the 2003 drilling program, Enterra plans to drill seven wells with further downspacing in the centre of the pool as well as initiate a waterflood feasibility study for the pool. The reservoir has net pays up to 40 m (130 ft). Enterra owns a 3-D seismic program that covers the Sylvan Lake Pekisko G pool.

Kaybob

This property is located 50 kilometers north of Edson, Alberta and is pipeline connected to a major gas and oil processing facility in the area. There is one well with a working interest of 100% on production in this property. With the construction of a pipeline tie-in in September 2003 and the addition of a gas-lift system in November 2003, the well was returned to production. The well is producing 130 bbl/d light crude oil with 110 mcf/d of associated gas.

McDaniel and Associates have assigned total proved reserves of 391 mbbl of oil, 230 mmcf of gas, and 8 mbbl of natural gas liquids to this property. Total proved and probable reserves are 548 mbbl of oil, 323 mmcf of gas, and 11 mbbl of natural gas liquids. Enterra acquired its interest in the Kaybob South Nisku C Pool in the year 2000. Enterra owns a 90% working interest in 320 acres of land, subject to a 7.5% NCORR on 100% of production. Enterra has a licensed copy of a 7 square mile 3-D program over the well and adjacent lands.

Reserves and Present Value Summary

Enterra is required to comply with the National Instrument 51-101, issued by the Canadian Securities Administrators, in all its reserves related disclosures. NI 51-101 came into effect on September 30, 2003 and is applicable for financial years ended on or after December 31, 2003. NI 51-101 brought about significant changes in which reporting issuers manage and publicly disclose information relating to their oil and gas reserves, mandates annual disclosure requirements and prescribes new reserve definitions as follows:

Proved reserves (P90) - this is a conservative estimate of remaining reserves. For reported reserves this means there must be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Proved plus Probable (P50) - this is a reasonable estimate of remaining reserves. For reported reserves there must be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable reserves. The probable reserves will no longer be risked by 50 percent as they are implicitly risked due to the nature of the new definition of reserves.

The purpose of NI 51-101 is to enhance the quality, consistency, timeliness and comparability of oil and gas activities by reporting issuers and elevate reserves reporting to a higher level of accountability.

In the United States, registrants [other than foreign private issuers] are required to disclose reserves using the standards contained in U.S. Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with United States Statement of Financial Accounting Standards No.69 "Disclosures About Oil and Gas Producing Activities"("FAS 69"). As a foreign private issuer, Enterra is permitted to comply with the disclosure requirements contained in NI 51-101 for the purposes of its U.S. regulatory filings. Unless otherwise indicated, all of the reserves and production information disclosure in this Form 20-F is in compliance with NI 51-101.

-17-

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i)the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii)the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. Enterra concurs with this assessment.

In this Form 20-F, certain natural gas volumes have been converted to barrels of oil equivalent (""BOEs")on the basis of six thousand cubic feet (""Mcf")to one barrel (""bbl"). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

Reserve volumes and values at December 31, 2003 are based on Enterra's interest in its total proved and probable reserves prior to royalties as defined in NI 51-101. Reserve volumes and values for previous years are based on "established" (proved plus 50% probable) reserves prior to deduction of royalties. Under those definitions, probable reserves were discounted by an arbitrary risk factor of 50% in reporting established reserves. Under NI 51-101 reserves definitions, estimates are prepared such that the full proved and probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "most likely case"). As such, the probable reserves now reported are already "risked". Overall there were no material revisions to Enterra's reserve volumes in transitioning to NI 51-101.

Enterra had its reserves evaluated by independent engineers every year. Enterra's 2003 reserves were independently evaluated as at December 31, 2003 by McDaniel and Associates Consultants Ltd. ("McDaniel") for all its properties, excluding the properties acquired in East Central Alberta. This acquisition was completed on January 30, 2004 and was evaluated by Gilbert Lausten Jung Associates Ltd. ("GLJ").

Reserve Continuity

Oil and Gas (mboe)

	Proved	Probable	Total
December 31, 2000	2,261.4	643.5	2,904.9
Discoveries and extensions	1,224.8	615.2	1,840.0
Purchases	3,277.1	981.7	4,258.8
Dispositions	(113.1)	(30.0)	(143.1)
Production	(695.5)	-	(695.5)
Revision of prior estimates	(67.7)	56.1	(11.6)
December 31, 2001	5,887.0	2,236.7	8,153.5
Discoveries and extensions	3,502.9	2,292.8	5,795.7
Dispositions	(931.9)	(441.1)	(1,373.0)
Production	(846.7)	-	(846.7)
Revision of prior estimates	(235.0)	(423.6)	(658.6)
December 31, 2002	7,376.3	3,694.6	11,070.9
Discoveries and extensions	2,800.6	860.1	3,660.7
Purchases	139.5	32.4	171.9
Dispositions	(1,707.2)	(929.6)	(2,636.8)
Production	(1,833.2)	-	(1,833.2)
Revision of prior estimates	(633.1)	(1,365.6)	(1,998.7)
December 31, 2003	6,142.9	2,291.9	8,434.8
Acquisition East Central Alberta properties	2,377.2	1,051.0	3,428.2
Total	8,520.1	3,342.9	11,863.0

Proved plus probable reserves, including the East Central Alberta acquisition, increased by 7.15% to 11.9 mmboe from 11.1 mmboe at the end of 2002. Total proved reserves increased by 15.5% to 8.5 mmboe from 7.4 mmboe at the end of 2002. Total probable reserves decreased by 9.5% to 3.3 mmboe from 3.7 mmboe at the end of 2002. The larger decrease in probable reserves is mainly due to the waterflood program at Clair which caused most of the 2002 probable reserves to be transferred to the proved category in 2003.. The new NI-51-101 policy does not affect the 2002 reserves but discounts the 2003 probable reserves by an additional 50% "risk factor". Total proved reserves represent 72% (2002 74%) of total reserves .

-18-

Enterra s finding costs over the last 3 years are highlighted below, along with the recycle ratios for each year. The recycle ratio is a critical measure of any success in the oil and gas industry. It compares the netbacks with the finding costs. Basically, a recycle ratio of 1 is a "break even point", indicating that the enterprise earns the same amount when selling its production as it pays when finding new production.

Finding costs and recycle ratio

(in $/boe, except for capital expenditures which are in thousands)

	3-year average	2003	2002	2001
Capital expenditures ***(including East Central acquisition)***		$71,424	$35,881	$49,309
Reserves				
Proved reserves added in the year (in mboe)	13,322.0	5,317.4	3,502.8	4,501.8
Probable reserves added in the year (in mboe)	5,800.6	1,911.1	2,292.6	1,596.9
Established reserves added in the year (in mboe) (1)	17,177.8	7,228.5	4,649.1	5,300.2
Finding costs				
Proved reserves ($/boe)	$11.76	$13.43	$10.24	$10.95
Established reserves ($/boe)	$9.12	$9.88	$7.72	$9.30
Recycle ratio (netbacks divided by finding costs)				
Corporate netbacks ($/boe) (2)	$17.63	$20.08	$14.89	$14.52
Corporate recycle ratio (based on established finding costs)	1.93	2.03	1.93	1.56

Operating netbacks ($/boe) [3]	$20.28	$22.72	$18.34	$16.18
Operating recycle ratio (based on established reserves)	2.22	2.30	2.38	1.74

[1] *Established reserves were proved plus 1/2 probable reserves in 2001 and 2002, and proved plus probable reserves in 2003*

[2] *Corporate netbacks are production revenue less royalties, operating costs, G&A and interest expense*

[3] *Operating netbacks are production revenue less royalties and operating costs*

The estimated oil and natural gas reserves of Enterra and the associated estimated present value of estimated future net cash flows have been evaluated in a report as of December 31, 2003 prepared by McDaniel and by GLJ for the East Central Alberta properties.

The following table is based on the McDaniel and GLJ reports that show the estimated share of the remaining oil, natural gas and natural gas liquids attributable to Enterra and the estimated present value of estimated future net cash flows for these reserves, using escalating prices and costs. All estimates of present value of future net cash flows are stated after provision for capital expenditures required to generate such revenues but prior to provision for indirect costs such as general and administrative overhead, income taxes or interest expense. It should not be assumed that the estimated present values of future net cash flows are representative of the fair market value of the reserves. These recovery and reserve estimates of Enterra s interests in the described properties are estimates only; the actual reserves in the properties in which we have an interest may be more or less than those calculated. Assumptions and qualifications relating to costs, prices and other matters are summarized in the notes to the following table. The extent and character of the material information supplied by Enterra including, but not limited to, ownership, well data, production, price, revenues, operating costs and contracts were relied upon by McDaniel and GLJ in preparing the report. In the absence of such information, McDaniel and GLJ relied upon their opinion of reasonable practice in the industry. The McDaniel and GLG reports may be examined at the office of Enterra located at Suite 2600, 500- 4th Avenue S.W., Calgary, Alberta during normal business hours. All monetary amounts are expressed in Canadian dollars.

Estimated Petroleum and Natural Gas Reserves and Net Present Value

December 31, 2003

	Light/ Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	NGL s (mmbl)	Total (mboe)	NPV 0%	NPV 10%	NPV 15%
McDaniel report								
Proved Producing	2,563.7	1,814.4	5,330.1	45.3	5,311.8	$78,467	$67,943	$63,458
Proved Non-Producing	679.8	0.0	774.0	22.2	831.0	$18,315	$15,277	$14,188

Total Proved	3,243.5	1,814.4	6,104.1	67.5	6,142.8	$96,782	$83,220	$77,646
Total Probable	1,359.0	589.7	1,926.7	22.2	2,292.0	$41,065	$28,661	$24,664
Total Proved and Probable	4,602.5	2,404.1	8,030.8	89.7	8,434.8	$137,847	$111,881	$102.310
GLJ report								
Proved Producing	1,390.9	349.9	1243.7	25.1	1,973.2	$15,354	$12,159	$11,122
Proved Non-Producing	114.2	223.2	378.2	3.5	404.0	$2,827	$1,611	$1,301
Total Proved	1,505.1	573.1	1,621.9	28.6	2,377.2	$18,181	$13,770	$12,423
Total Probable	393.5	407.0	1,347.3	25.9	1,051.0	$6,843	$4,262	$3,534
Total Proved and Probable	1,898.6	980.1	2,969.2	54.5	3,428.2	$25,024	$18,032	$15,957
Combined reports								
Proved Producing	3,954.6	2,164.3	6,573.8	70.4	7,285.0	$93,821	$80,102	$74,580
Proved Non-Producing	794.0	223.2	1,152.2	25.7	1,235.0	$21,142	$16,888	$15,489
Total Proved	4,748.6	2,387.5	7,726.0	96.1	8,520.0	$114,963	$96,990	$90.069
Total Probable	1,752.5	996.7	3,274.0	48.1	3,343.0	$47,908	$32,923	$28,198
Total Proved and Probable	6,501.1	3,384.2	11,000.0	144.2	11,863.0	$162,871	$129,913	$118,267

Historical Reserves

The following table sets out Enterra s proved oil and gas reserves at December 31, 2003, 2002 and 2001 respectively. The monetary amounts are expressed in Canadian dollars.

As at December 31

	2003 (1)	2002	2001
Proved Producing Reserves:			
Oil and NGL s (mbbls)	4,447	4,443	3,431
Gas (mmcf)	5,334	10,930	7,684
Proved Reserves:			

Oil and NGL s (mbbls)	5,149	5,803	4,133
Gas (mmcf)	6,108	13,287	10,707

[1] including East Central Alberta acquisition

Land Holdings

At December 31 Enterra had the following land holdings

	2003	2002	2001
Developed acres (net)	13,394	28,355	22,646
Undeveloped acres (net)	42,686	51,581	58,590
Total acres (net)	56,080	79,936	81,236

-20-

Production

The following table summarizes Enterra s working interest production during the periods indicated:

	Years ended December 31,						
	2003	2002	2001	2000	1999	1998	1997
Oil and NGL s (MBbls)	1,409	533	582	410	93	86	79
Gas (MMcf)	2,545	1,882	680	63	61	220	58
Total (MBOE)	1,834	847	695	421	100	108	85
Average Production in BOED	5,024	2,320	1,906	1,150	274	296	233

D

efinitions:

"*BOEPD*" means barrels of oil equivalent produced per day.

"*MBOE*" means thousands of barrels of oil equivalent, meaning one barrel of oil or one barrel of natural gas liquids or ten mcf of natural gas.

"*MBbls*" means thousands of barrels, with respect to production of crude oil or natural gas liquids.

"*MMcf*" means millions of cubic feet, with respect to production of natural gas.

"*NGL s*" means natural gas liquids, being those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof.

Drilling

Enterra s drilling history is as follows (there were no wells drilled in 1997 and 1999):

	2003	2002	2001	2000	1998
Wells drilled	Gross (Net)	Gross (Net)	Gross (Net)	Gross (Net)	Gross (Net)
Oil	31 (31.0)	25 (23.7)	9 (4.97)	9 (8.26)	0 (0.00)
Natural Gas	3 (1.1)	37 (34.0)	8 (3.78)	2 (1.27)	0 (0.00)
Injection and water disposal	6 (6.0)				
Abandoned	7 (6.4)	0 (00.0)	3 (1.84)	2 (1.14)	1 (0.13)
Total	47 (44.5)	62 (57.7)	20 (10.59)	13 (10.67)	1 (0.13)

_

Notes:

(1) "Gross" wells means the number of whole wells.

(2) "Net" wells means Enterra s working interest in the gross wells.

Capital Expenditures

The following table summarizes the capital expenditures made by Enterra during the periods indicated, expressed in Canadian dollars:

(In Thousand s)	Years ended December 31,						
	2003	2002	2001	2000	1999	1998	1997
	($9,724)	$ 383	$52,374	$ 8,220	$ 1,879	$ 244	$ 500

Property acquisitions (net of disposals)							
Drilling (exploration and development)	28,390	21,090	5,821	6,922	341	27	50
Facilities	14,368	9,347	1,412	56	728	4	0
Miscellaneous	286	235	1,011	156	24	2	34
Total	$ 33,320	$ 30,289	$68,618	$ 15,354	$2,972	$ 277	$ 584

-21-

Oil and Gas Wells

The following table summarizes Enterra s interest in producing and non-producing oil and gas wells as at December 31, 2003:

Property	Producing Oil Wells Gross	Producing Oil Wells Net	Producing Gas Wells Gross	Producing **Gas Wells** Net
Kaybob	1	0.9		
Highvale			2	0.75
Leduc	1	0.39		
Garden Plains			1	0.62
Gilby			1	0.39
Leedale			1	0.02
Lubicon	1	0.23		
Willesden Green	101	5.98	1	0.43
Timber Draw	1	0.15		
Sounding Lake East	17	16.50		
Sounding Lake West	55	27.50		
Sounding Lake North	22	6.92		

Sylvan Lake	24	22.75	1	0.32
Clair	28	28.00	5	5.00
Gordondale	1	0.50	2	1.00
Rolla			2	1.00
Swan Hills	1	0.50		
Campbell	1	0.12		
Total Wells	254	110.44	16	9.53

Employees

At December 31, 2003 we had approximately 30 employees and consultants working both in the Calgary head office and in field operations.

Office Facilities

Enterra currently leases 10,450 square feet of office space at Suite 2600, 500 - 4th Avenue S.W. in Calgary, Alberta in a lease that commenced November 1, 2001. The lease has a three-year term (expiring on November 30, 2004) and the annual rental is currently C$28.64 per square foot (including operating costs and property taxes).

Competition

The petroleum industry is highly competitive. Enterra competes with numerous other participants in the acquisition of oil and gas leases and properties, and the recruitment of employees. Any company can make acquisitions and bid on provincial leases in Alberta. Competitors include oil companies and other income trusts, many of whom have greater financial resources, staff and facilities than those of Enterra. Our ability to increase reserves in the future will depend not only on our ability to develop existing properties, but also on our ability to select and acquire suitable additional producing properties or prospects for drilling. We also compete with numerous other companies in the marketing of oil. Competitive factors in the distribution and marketing of oil include price and methods and reliability of delivery.

Government Regulation in Canada

The oil and natural gas industry is subject to extensive controls and regulations governing its operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the Canadian oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of Enterra in a manner materially different from how they would affect other oil and gas companies of similar size operating in Western Canada. All current legislation is a matter of public record and Enterra is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing   Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada, or NEB. Any oil export to be made pursuant to a contract of longer duration, to a maximum of 25 years, requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council. In addition, the prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to twenty years, in quantities of not more than 30,000 m^3/day, must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration, up to a maximum of 25 years, or a larger quantity, requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The governments of British Columbia and Alberta also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve ability, transportation arrangements and market considerations.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

In the Province of Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit or, ARTC program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per thousand cubic metres and 25% at prices at and above $210 per thousand cubic metres. The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better-targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program. Such rules will not presently preclude Enterra from being eligible for the ARTC program.

Crude oil and natural gas royalty holidays for specific wells and royalty reductions reduce the amount of Crown royalties paid by Enterra to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act*, or EPEA, which came into force on September 1, 1993. The EPEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties for violations. Enterra is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. Enterra believes that it is in material compliance with applicable environmental laws and regulations. Enterra also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Additional Information Relating to the Trust

Income Streams and Distribution Policy

A portion of the cash flows generated by the assets held, directly or indirectly, by the Trust is distributed to holders of trust units. The Trustee may, in respect of any period, declare payable to the unitholders all or any part of the net income of the Trust, less all expenses and liabilities of the Trust due and accrued and which are chargeable to the net income of the Trust.

The New Enterra Board currently intends to provide all unitholders with monthly cash distributions of approximately USD $0.10 per trust unit. However, the availability of cash flows for the payment of distributions will at all times be dependant upon a number of factors, including resource prices, production rates and reserve growth and the New Enterra Board cannot assure that cash flows will be available for distribution to unitholders in the amounts anticipated or at all. See "*Risk Factors*".

Our primary sources of cash flow is payments from New Enterra of interest on the principal amount of the Series A Notes and payments from EEC Trust of interest on the principal amount of the CT Note.

The Series A Notes

Pursuant to the Arrangement, New Enterra issued the Series A Notes to the Trust. The principal amount of the Series A Notes issued is $125,000,000. The Series A Notes are unsecured and bear interest from the date of issue at 14% per annum. Interest is payable for each month during the term on the 15th day of the month following such month.

CT Note

The CT Note is a subordinated, demand participating promissory note. The CT Note bears interest at a rate that will be re-set from time to time so as to approximate the return on the shares of New Enterra held by EEC Trust. Redemptions and returns of capital on shares of New Enterra held by EEC Trust may be required to be applied as prepayments of the principal balance of the CT Note.

Trust Units

An unlimited number of trust units may be created and issued pursuant to the Trust Indenture. Each trust unit entitles the holder thereof to one vote at any meeting of the holders of trust units and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All trust units rank among themselves equally and rateably without discrimination, preference or priority. Each trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the trust units held by such holder (see "*Redemption Right*") and to one vote at all meetings of unitholders for each trust unit held. In addition, in certain circumstances unitholders will have the right to instruct the trustees of EEC Trust with respect to the voting of shares of New Enterra held by EEC Trust at meetings of holders of shares of New Enterra. See "*Meetings of Unitholders*" and "*Exercise of Voting Rights*".

The trust units do not represent a traditional investment and should not be viewed by investors as "shares" in either New Enterra, or the Trust. As holders of trust units in the Trust, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions.

The price per trust unit is a function of anticipated distributable income generated by New Enterra and the ability of New Enterra to effect long term growth in the value of the Trust. The market price of the trust units is sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and the ability of New Enterra to acquire additional assets. Changes in market conditions may adversely affect the trading price of the trust units.

The trust units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Special Voting Rights

The Trust Indenture allows for the creation of Special Voting Rights which will enable the Trust to provide voting rights to holders of Exchangeable Shares and, in the future, to holders of other exchangeable shares that may be issued by New Enterra or other subsidiaries of the Trust in connection with other exchangeable share transactions.

Holders of Special Voting Rights are not be entitled to any distributions of any nature whatsoever from the Trust and each holder shall be entitled to attend at meetings of unitholders and, subject to the terms of the instrument creating the Special Voting Rights, is entitled to that number of votes equal to the number of votes attached to the trust units for which the Special Voting Rights held by such holder are exchangeable, exercisable or convertible. Holders of Special Voting Rights are also be entitled to receive all notices, communications or other documentation required to be given or otherwise sent to holders of trust units. Except for the right to attend and vote at meetings of unitholders and receive notices, communications and other documentation sent to unitholders, the Special Voting Rights do not confer upon the holders thereof any other rights.

Under the terms of the Voting and Exchange Trust Agreement, the Trust has issued a Special Voting Right to the Voting and Exchange Trust Agreement Trustee for the benefit of every person who received Exchangeable Shares pursuant to the Arrangement.

Unitholder Limited Liability

The Trust Indenture provides that no unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust or its obligations or affairs and, in the event that a court determines unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a unitholder from or arising as a result of such unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon unitholders personally. Notwithstanding the terms of the Trust Indenture, unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to unitholders of this nature arising is considered unlikely in view of the fact that the sole activity of the Trust is to hold securities, and all of the business operations are carried on by New Enterra, directly or indirectly.

- 25 -

The activities of the Trust, the EEC Trust, New Enterra and the Partnership is conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of New Enterra and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon unitholders personally.

Redemption Right

Trust units are redeemable at any time on demand by the holders thereof upon delivery to the transfer agent of the Trust of the certificate or certificates representing such trust units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem trust units by the transfer agent, the holder thereof shall only be entitled to receive a price per trust unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Where more than one market exists for the trust units, the principal market shall mean the market on which the trust units experience the greatest volume of trading activity on the date or for the period in question, as applicable.

For the purposes of this calculation, "market price" is an amount equal to the simple average of the closing price of the trust units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the trust units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the trust units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the trust units for each day that there was trading, if the market provides only the highest and lowest prices of trust units traded on a particular day. The closing market price is: an amount equal to the closing price of the trust units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the trust units if there was trading and the exchange or other market provides only the highest and lowest prices of trust units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by the Trust in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of unitholders to receive cash upon the redemption of their trust units is subject to the limitation that the total amount payable by the Trust in respect of such trust units and all other trust units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that New Enterra may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of trust units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Series A Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Series A Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to the unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall (herein referred to as "Redemption Notes"). Notwithstanding the foregoing, the distribution of any Series A Notes and the issuance of any Redemption Notes shall be conditional upon the receipt of all necessary regulatory approvals and the making of all necessary governmental registrations, declarations and filings, including, without limitation, any required registration of the Series A Notes or Redemption Notes, as applicable, to be distributed or issued in respect of the payment of the Market Redemption Price, and any required qualification of the Trust Indenture relating to such Series A Notes or Redemption Notes, under the securities laws of the United States.

If at the time trust units are tendered for redemption by a unitholder, (i) the outstanding trust units are not listed for trading on the TSX or Nasdaq and are not traded or quoted on any other stock exchange or market which New Enterra considers, in its sole discretion, provides representative fair market value price for the trust units, or (ii) trading of the outstanding trust units is suspended or halted on any stock exchange on which the trust units are listed for trading or, if not so listed, on any market on which the trust units are quoted for trading, on the date such trust units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such trust units were tendered for redemption then such unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per trust unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by New Enterra as at the date on which such trust units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Series A Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Series A Notes or Redemption Notes which may be distributed in specie to unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Series A Notes or Redemption Notes. Series A Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Meetings of Unitholders

The Trust Indenture provides that meetings of unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under "Amendments to the Trust Indenture"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding up the affairs of the Trust.

A meeting of unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned in writing by (i) New Enterra or (ii) the holders of trust units and Special Voting Rights holding in aggregate not less than 5% of the votes entitled to be voted at a meeting of unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of unitholders either in person or by proxy and a proxyholder need not be a unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5% of the votes attaching to all outstanding trust units shall constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the holders of any issued Special Voting Rights who are present at the meeting shall be regarded as representing outstanding trust units equivalent in number to the votes attaching to such Special Voting Rights.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of unitholders in accordance with the requirements of applicable laws.

Voting Of EEC trust units

There will be a meeting of the holders of EEC trust units immediately following each meeting of unitholders for the purpose of directing the Trustee as to the manner in which the Trustee shall vote the EEC trust units held by the Trust in respect of those matters voted on at such meeting of unitholders. Any resolution passed by unitholders pertaining to the manner in which EEC trust units held by the Trust are to be voted by the Trustee in respect of a particular matter which is to be put forth to the holders of EEC trust units for vote at a contemplated meeting (including by written resolution) of holders of EEC trust units, shall be deemed to be a direction to the Trustee in respect of the EEC trust units held by the Trust to, as applicable, either vote such EEC trust units in favour of or in opposition to, or to vote or with-hold from voting in respect of such matter in equal proportions to the votes cast by unitholders in respect of the matter, and the Trustee is obligated to vote, in respect of such matter if put forth to the holders of EEC trust units at a meeting of such holders, the EEC trust units held by the Trust in accordance with such direction.

Exercise of Voting Rights

The Trustee is prohibited from authorizing or approving:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by the Trust, except in conjunction with an internal reorganization of the direct or indirect assets of the Trust, as a result of which the Trust has substantially the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving the Trust and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above; or

(c) the winding up, liquidation or dissolution of the Trust prior to the end of the term of the Trust except in conjunction with an internal reorganization as referred to in paragraph (a) above;

without the prior approval of the unitholders by Special Resolution at a meeting of unitholders called for that purpose.

In addition, the Trustee is prohibited from authorizing EEC Trust to vote any shares of New Enterra in respect of:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by Enterra, the Trust or the Partnership, except in conjunction with an internal reorganization of the direct or indirect assets of New Enterra, EEC Trust or the Partnership, as the case may be, as a result of which EEC Trust has substantially the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving New Enterra, EEC Trust or the Partnership and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) the winding up, liquidation or dissolution of New Enterra, EEC Trust or the Partnership prior to the end of the term of EEC Trust, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of New Enterra to increase or decrease the minimum or maximum number of directors;

(e) any material amendments to the articles of New Enterra to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of New Enterra's shares in a manner which may be prejudicial to EEC Trust; or

(f) any material amendment to the CT Indenture or the Partnership Agreement which may be prejudicial to EEC Trust;

without the prior approval of the unitholders by Special Resolution at a meeting of unitholders called for that purpose.

Finally, the Trustee is prohibited from authorizing EEC Trust to vote any shares of New Enterra with respect to any matter which under applicable law (including policies of Canadian securities commissions) or applicable stock exchange rules would require the approval of the holders of shares of New Enterra by ordinary resolution or special resolution, without the prior approval of the unitholders by Ordinary Resolution or Special Resolution, as the case may be.

Trustee

Olympia Trust Company is the initial trustee of the Trust. The Trustee is responsible for, among other things, accepting subscriptions for trust units and issuing trust units pursuant thereto, maintaining the books and records of the Trust and providing timely reports to holders of trust units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

- 28 -

The initial term of the Trustee's appointment is until the third annual meeting of unitholders. The unitholders shall, at the third annual meeting of unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of unitholders three years following the reappointment or appointment of the successor to the Trustee. The Trustee may also be removed by Special Resolution of the unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The New Enterra Board has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to New Enterra responsibility for any and all matters relating to the following: (i) an offering of securities of the Trust; (ii) ensuring compliance with all applicable laws, including in relation to an offering of securities of the Trust; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of trust units or rights to trust units; (vi) all matters relating to the redemption of trust units; (vii) all matters relating to the voting rights on any instruments held by the Trust, other than the EEC trust units; and (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of The Trustee

The Trustee, its directors, officers, employees, shareholders and agents is not be liable to any unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the property of the Trust, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, prima facie, properly executed, any depreciation of, or loss to, the property of the Trust incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of New Enterra, or any other person to whom the Trustee has, with the consent of New Enterra, delegated any of its duties hereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by New Enterra to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the property of the Trust. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to The Trust Indenture

The Trust Indenture may be amended or altered from time to time by special resolution of the unitholders. The Trustee may, without the approval of any of the unitholders, amend the Trust Indenture for the purpose of:

(a) ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority;

(b) ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) and paragraph 132(8)(a) of the Tax Act as from time to time amended or replaced;

(c) providing for and ensuring (i) the allocation of items of income, gain, loss, deduction and credit in respect of the Trust for United States federal income tax purposes; (ii) the filing of income tax returns necessary or desirable for the purposes of United States federal income tax; or (iii) compliance by the Trust with any other applicable provisions of United States federal income tax law;

(d) ensuring that such additional protection is provided for the interests of unitholders as the Trustee may consider expedient;

(e) removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any other agreement of the Trust or any offering document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the unitholders are not prejudiced thereby;

(f) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the unitholders are not prejudiced thereby; and

(g) changing the situs of or the laws governing the Trust which, in the opinion of the Trustee, is desirable in order to provide unitholders with the benefit of any legislation limiting their liability.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding trust units; (b) a quorum of 50% of the issued and outstanding trust units is present in person or by proxy; and (c) the termination must be approved by special resolution of unitholders.

Unless the Trust is earlier terminated or extended by vote of the unitholders, the Trust shall continue in full force and effect for a period which shall end twenty-one years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II. In the event that the Trust is wound up, the Trustee will sell and convert into money the property of the Trust in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the property of the Trust in accordance with any applicable laws or requirements of any governmental agency or authority, and shall in all respects act in accordance with the directions, if any, of the unitholders in respect of termination authorized pursuant to the special resolution of the unitholders authorizing the termination of the Trust. After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the unitholders in accordance with their pro rata interests.

Reporting to Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trustee to unitholders and the unaudited interim financial statements of the Trust will be mailed to unitholders within the periods prescribed by securities legislation. The year end of the Trust shall be December 31. The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

The Trust is subject to the reporting requirements of the 1934 Act applicable to foreign private issuers, and in connection therewith will file or submit reports, including annual reports and other information with the U.S. Securities and Exchange Commission (the "SEC"). Such reports and other information can be inspected and copied at the public reference facilities maintained by the SEC at 450 Fifth Street, N.W., Room 1024, Judiciary Plaza, Washington, D.C. The Trust's SEC filings and submissions will also be available to the public on the SEC's web site at http://www.sec.gov.

- 30 -

ITEM 5. Operating and Financial Review and Prospects

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

The following management s discussion and analysis of Enterra Energy Trust ("Enterra or the Trust") is as of April 16, 2004 and should be read in conjunction with the audited consolidated financial statements of the Trust for the years ended December 31, 2003 and 2002, together with accompanying notes, which have been prepared in accordance with Canadian generally accepted accounting principles. The significant differences to generally accepted accounting principles of the United States of America are as set out in note 17. Discussion with regard to the Trust s 2004 outlook is based on currently available information. All amounts are stated in Canadian dollars except where otherwise indicated. Natural gas volumes have been converted to a crude oil equivalent using a ratio of 6 mcf to 1 bbl of oil.

Cash flow, expressed before changes in non-cash working capital, is used by Enterra to measure and evaluate operating performance and liquidity. Earnings from operations, which is calculated before income taxes and before gains or losses on disposal of assets, is used by Enterrra to measure and evaluate operating performance. Cash flow and earnings from operations do not have any standardized meaning prescribed by the Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable with the calculation of similar measures for other companies.

It is management s view, based on its communications with investors during events like conference calls, webcasts or road shows, that these non-GAAP measures are most relevant to our investors and unitholders, especially since Enterra s conversion to an oil and gas income trust. Earnings from operations, because it excludes one-time non-recurring events, can provide investors with an undistorted frame of reference when comparing performance from year to year or quarter to quarter. Cash flow from operations is also extremely relevant to investors because it is the starting point for setting the monthly distribution level.

Both cash flow from operations and earnings from operations are reconciled to GAAP earnings in tables included in the management discussion and analysis section.

Special Note Regarding Forward-Looking Statements

This annual report includes forward-looking statements. All statements other than statements of historical facts contained in this annual report, including statements regarding our future financial position, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words "believe," "may," "will," "estimate," "continue," "anticipate," "intend," "should," "plan," "expect" and similar expressions, as they relate to us, are intended to identify forward-looking statements. We have based these forward-looking statements largely on our current expectations and projections about future events and financial trends that we believe may affect our financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions described in "Risk Factors" and elsewhere in this annual report.

Other sections of this annual report may include additional factors which could adversely affect our business and financial performance. Moreover, we operate in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for our management to predict all risk factors, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

We undertake no obligation to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. We cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

Critical Accounting Policies

The Company follows the full cost method of accounting for oil and natural gas properties and equipment whereby we capitalize all costs relating to its acquisition of, exploration for and development of oil and natural gas reserves. Enterra s consolidated financial condition and results of operations are sensitive to, and may be adversely affected by, a number of subjective or complex judgments relating to methods, assumptions or estimates required under the full cost method of accounting concerning the effect of matters that are inherently uncertain. For example:

(i) Capitalized costs under the full cost method are generally depleted and depreciated using the unit-of-production method, based on estimated proved oil and gas reserves as determined by independent engineers. In addition, capital costs are also restricted from exceeding the sum of the estimated future net revenues of those properties, plus the cost or estimated fair value of unproved properties less estimated future abandonment and site restoration costs, general administrative expenses, financing costs and income taxes (the "ceiling test"). Should this comparison indicate an excess carrying value, a write-down would be recorded. To economically evaluate the Enterra s proved oil and natural gas reserves, these independent engineers must necessarily make a number of assumptions, estimates and judgments that they believe to be reasonable based upon their expertise and professional and CICA and SEC guidelines. Were the independent engineers to use differing assumptions, estimates and judgments, then Enterra s consolidated financial condition and results of operations would be affected. For example, Enterra would have lower revenues and net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in lower reserve estimates, since our depletion and depreciation rate would then be higher and it might also result in a write-down under the ceiling test. Similarly, Enterra would have higher revenues and net profits (or lower net losses) in the event the revised assumptions, estimates and judgments resulted in higher reserve estimates.

(ii) Enterra s management also periodically assesses the carrying values of unproved properties to ascertain whether any impairment in value has occurred. This assessment typically includes a determination of the anticipated future net cash flows based upon reserve potential and independent appraisal where warranted. Impairment is recorded if this assessment indicates the future potential net cash flows are less than the capitalized costs. Were Enterra s management to use differing assumptions, estimates and judgments, then Enterra s consolidated financial condition and results of operations would be affected. For example, Enterra would have lower net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in increased impairment expense.

(iii) Estimated future restoration costs are provided for using the unit of production method based on estimated gross proved reserves. Costs are estimated by our engineers based on current regulations, costs, technology and industry standards. The annual charge is recorded as a provision for future site restoration and abandonment costs. Removal and site restoration expenditures are charged to the accumulated provision as incurred.

Results of Operations 2003 compared to 2002

Overview

Enterra managed to achieve record revenue, cash flow and earnings in 2003 while converting itself to an oil and gas income trust during the fourth quarter. Cash flow from operations, excluding the one-time re-organization costs of $5.8 million, was in excess of $36 million for the year or $1.92 on a per unit basis. As a trust, Enterra established its initial monthly distribution level at US$0.10 per unit. The first distribution was paid on January 15, 2004 for the month of December 2003. Enterra drilled 47 wells in 2003, including 20 wells at Clair and 19 wells at Sylvan Lake. The two projects represented almost 60% of Enterra s 2003 capital expenditures. The 2003 drilling program resulted in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate.

Summarized financial and operational data ***(in Thousand s except for volumes and per unit/ share amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Exit production rate (boe per day)	6,460	5,335	+ 21%	6,460	5,335	+ 21%
Average production revenue	$15,598	$10,060	+ 55%	$72,097	$25,746	+180%
Average production volumes (boe per day)	5,206	3,221	+ 62%	5,024	2,320	+117%
Cash flow from operations [(1) (3)]	$ 7,467	$ 4,851	+ 54%	$36,455	$11,950	+205%
Cash flow from operations per unit/share [(1) (3)]	$ 0.37	$ 0.26	+ 40%	$ 1.92	$ 0.65	+195%
Earnings from operations [(2) (3)]	$1,019	$ 1,108	- 8%	$12,835	$ 2,909	+341%
Earnings from operations per unit/share [(2) (3)]	$ 0.05	$ 0.06	- 17%	$ 0.68	$ 0.16	+326%
Average number of units outstanding *(after giving effect to trust conversion)*	20,205	18,337	+ 10%	18,954	18,309	+ 4%
Average price per bbl of oil	$ 31.78	$ 34.93	- 9%	$ 39.12	$ 33.86	+ 16%
Average price per mcf of natural gas	$ 5.91	$ 5.34	+ 11%	$ 6.65	$ 4.08	+ 63%
Operating costs per boe	$ 6.19	$ 7.88	- 21%	$ 6.96	$ 7.11	- 2%
General and administrative expenses per boe *(cash portion)*	$ 1.59	$ 1.71	- 7%	$ 1.69	$ 1.99	- 15%

(1) Excluding re-organization costs of $5.8 million in year and Q4, 2003

(2) Excluding income taxes, re-organization costs of $5.8 million in 2003 and $3.1 million gain on redemption of preferred shares in 2002

(3) Both cash flow from operations and earnings from operations are non-GAAP measures. It is management s view that this information is relevant for investors in order to compare 2003 with 2002 without the impact of one-time non-recurring events. Both cash flow from

operations and earnings from operations are reconciled to GAAP earnings in the earnings and cash flow sections of the management discussion and analysis.

QUARTERLY INFORMATION

Quarterly information ***(In Thousand s, except per unit/ share data)***

	Q1 2003	Q1 2002	Q2 2003	Q2 2002	Q3 2003	Q3 2002	Q4 2003	Q4 2002
Revenue	$ 22,002	$ 5,598	$ 18,484	$ 5,051	$ 16,012	$ 5,036	$ 15,598	$ 10,060
Income from operations	$ 7,192	$ 326	$ 2,699	$ 620	$ 1,924	$ 854	$ 1,019	$ 1, 108
Per unit/share, basic	$ 0.39	$ 0.02	$ 0.15	$ 0.03	$ 0.10	$ 0.04	$ 0.04	$ 0.06
Per unit/share, diluted	$ 0.37	$ 0.02	$ 0.14	$ 0.03	$ 0.09	$ 0.04	$ 0.08	$ 0.05
Net earnings	$ 4,186	$ 3,150	$ 4,965	$ 398	$ 956	$ 714	$ (5,104)	$ 715
Per unit/share, basic	$ 0.23	$ 0.17	$ 0.27	$ 0.02	$ 0.05	$ 0.04	$ (0.28)	$ 0.04
Per unit/share, diluted	$ 0.21	$ 0.17	$ 0.25	$ 0.02	$ 0.05	$ 0.04	$ (0.25)	$ 0.03

3 YEAR SUMMARY

Summarized financial and operational data ***(in Thousand s except for volumes and per unit/share amounts)***

	Year 2003	Year 2002	Year 2001
Revenue	$72,097	$25,746	$20,264
Cash flow from operations (1) (4)	$36,455	$11,950	$ 9,810
Cash flow from operations per unit/share basic(1)	$ 1.92	$ 0.65	$ 0.70
Cash flow from operations per unit/share diluted(1)	$ 1.92	$ 0.63	$ 0.70

Earnings from operations [2] [4]	$12,835	$ 2,909	$ 3,228
Earnings from operations per unit/share - basic [2]	$ 0.68	$ 0.16	$ 0.23
Earnings from operations per unit/share - diluted [2]	$ 0.68	$ 0.15	$ 0.23
Net earnings	$ 5,004	$ 4,977	$ 1,617
Net earnings per unit/share - basic	$ 0.26	$ 0.27	$ 0.12
Net earnings per unit/share - diluted	$ 0.26	$ 0.27	$ 0.12
Average number of units outstanding *(after giving effect to trust conversion)*	18,954	18,309	13,985
Total assets	$ 116,230	$ 102,717	$ 80,063
Total long-term debt *(including bank debt and capital leases)*	$ 38,128	$ 29,358	$18,409
Distribution per unit [3]	US$ 0.10	N/A	N/A

(1) Excluding re-organization costs of $5.8 million in year and Q4, 2003

(2) Excluding income taxes, re-organization costs of $5.8 million in 2003,$3.1 million gain on redemption of preferred shares in 2002 and $929,037 in restructuring charges in 2001

(3) Only one distribution for the month of December 2003, paid on January 15, 2004 for US$0.10 per unit

4)

Both cash flow from operations and earnings from operations are non-GAAP measures. It is management s view that this information is relevant for investors in order to compare 2003, 2002 and 2001 without the impact of one-time non-recurring events. Both cash flow from operations and earnings from operations are reconciled to GAAP earnings in the earnings and cash flow sections of the management discussion and analysis.

- 33 -

PRODUCTION INCOME

Production income increased by 180% in 2003 from $25.7 million to $72.1 million. Approximately 30% of this increase was due to the higher commodity prices in effect during 2003 and 70% was due to the higher production volumes in 2003.

Production income increased by 55% in Q4, 2003 from $10.1 million to $15.6 million. All of this increase is due to higher production, as pricing actually decreased slightly in Q4, 2003 by 4%.

Enterra drilled 47 wells in 2003, including 20 wells at Clair and 19 wells at Sylvan Lake. The two projects represented almost 60% of Enterra s 2003 capital expenditures. The 2003 drilling program resulted in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate. Enterra s production in 2003 averaged 5,024 boe/day, consisting of 3,862 bbls/day of oil and 6,972 mcf/day of natural gas, for a mix of 77% oil and 23% natural gas.

Enterra s production in Q4 of 2003 averaged 5,206 boe/day, consisting of 4,110 bbls/day of oil and 6,572 mcf/day of natural gas, for a mix of 79% oil and 21% natural gas. Enterra s production in Q4 of 2002 averaged 3,221 boe/day, consisting of 2,142 bbls/day of oil and 6,477 mcf/day of natural gas, for a mix of 67% oil and 33% natural gas. Enterra drilled 15 wells in Q4, 2003 compared to 54 wells in Q4, 2002.

Enterra exited 2003 at a rate of 6,460 boe/day, consisting of 4,890 bbls/day of oil and 9,420 mcf/day of natural gas, for a mix of 76% oil and 24% natural gas. This represents a 21% increase over the 2002 exit rate of 5,335 boe/day.

Production income ***(in Thousand s except for volumes and pricing)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Crude oil and natural gas liquids	$12,022	$6,878	+ 75%	$ 55,185	$ 18,075	+ 205%
Natural gas	3,576	3,182	+ 12%	16,912	7,671	+ 120%
Total production income	$15,598	$10,060	+ 55%	$ 72,097	$ 25,746	+ 180%
Volumes						
Average oil production (in bbls/day)	4,110	2,142	+ 92%	3,862	1,460	+ 164%
Average gas production (in mcf/day)	6,572	6,477	+ 1%	6,972	5,157	+ 35%
Average total production (in boe/day)	5,206	3,221	+ 62%	5,024	2,320	+ 117%
Exit oil production (in bbls/day)	4,890	4,205	+ 16%	4,890	4,205	+ 16%
Exit gas production (in mcf/day)	9,420	6,780	+ 39%	9,420	6,780	+ 39%
Exit total production (in boe/day)	6,460	5,335	+ 21%	6,460	5,335	+ 21%
Commodity Pricing Benchmarks						
West Texas Intermediate (US$/bbl)	31.18	28.29	+ 10%	31.10	26.13	+ 19%

Exchange rate (US$)	0.7600	0.6372	+ 19%	0.7164	0.6371	+ 12%
Edmonton Par ($/bbl)	39.85	43.18	- 8%	43.39	40.20	+ 8%
NYMEX (US$/mmbtu)	5.44	4.33	+ 26%	5.49	3.36	+ 63%
Alberta Spot ($/mcf)	5.69	5.52	+ 3%	6.50	3.96	+ 64%
Commodity Prices received by Enterra						
Average price received per bbl of oil	31.78	34.93	- 9%	39.12	33.86	+ 16%
Average price received per mcf of natural gas	5.91	5.34	+ 11%	6.65	4.08	+ 63%

PRODUCTION EXPENSES

Production expenses increased by 112% in 2003 and by 27% in Q4 compared to their respective periods in 2002. These increases are consistent with the higher production levels in 2003. Both as a percentage of revenue and on a per boe basis, Enterra reduced its operating costs in 2003, mainly due to operating efficiencies gained at Clair in the fourth quarter of 2003 by implementing a sales line which eliminated trucking and terminal fees for that area. This is why the production expenses per boe were 21% lower in Q4, 2003 compared to 2002 ($6.19 per boe in 2003 compared to $7.88 per boe in 2002)

Production expenses ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Production expenses	$ 2,966	$ 2,335	+ 27%	$ 12,762	$ 6,018	+ 112%
As a percentage of production revenue	19%	23%	- 17%	18%	23%	- 22%
Production expenses per boe	$ 6.19	$ 7.88	- 21%	$ 6.96	$ 7.11	- 2%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, increased by 320% in 2003 and by 128% in Q4 compared to their respective periods in 2002. These increases are the result of both the increased production in 2003 and the higher commodity prices in effect during the year. Most royalties are calculated on a sliding scale based on commodity prices. As commodity prices increase, so do the royalty rates. Conversely, the Alberta Royalty Tax Credit is reduced as commodity prices increase. Since royalties are not calculated by reference to any hedging position entered into by Enterra, any hedging loss will result in a higher royalty expense as a percentage of production revenue. These factors were the reason for the increase (50% for the year and 47% for Q4) in royalty expense both as a percentage of production revenue and on a per boe basis.

Royalties ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Royalties	$ 3,916	$ 1,721	+ 128%	$ 17,656	$ 4,203	+ 320%
As a percentage of production revenue	25%	17%	+ 47%	24%	16%	+ 50%
Royalties per boe	$ 8.18	$ 5.81	+ 41%	$ 9.63	$ 4.96	+ 94%

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses increased by 84% in 2003 and 50% in Q4 compared to their respective periods in 2002. Approximately 80% of the increase in 2003 is the result of additional staffing requirements. Other areas which incurred higher expenses were marketing and travel costs, insurance premiums, and higher regulatory compliance costs both for the Canadian and U.S. exchanges. Capitalized general and administrative costs were consistent in both years, $1,787,000 (or 32% of total general and administrative expenses) in 2003 and $1,450,900 (or 39% of total general and administrative expenses) in 2002. The non-cash portion of general and administrative expenses in 2003 relate to the value assigned to 200,000 warrants (see Note 9(h) of the Financial Statements for details).

General and administrative expenses ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
General and administrative expenses cash portion	$ 760	$ 505	+ 50%	$ 3,103	$ 1,683	+ 84%
General and administrative expenses non-cash portion	-	-		$ 281	-	
As a percentage of production revenue (cash portion)	5%	5%	0%	4%	7%	- 43%
General and administrative expenses per boe (cash portion)	$ 1.59	$ 1.71	- 7%	$ 1.69	$ 1.99	- 15%

INTEREST EXPENSE

Interest expense increased by 42% in 2003 and decreased by 23% in Q4 compared to their respective periods in 2002. The 2003 increase is due to the higher average outstanding loan balances during the year. The decrease in Q4 is due to the fact that, on average, the Q4 loan balances were higher in 2002 because of the higher drilling activity in Q4, 2002 compared to Q4, 2003 (54 wells were drilled in Q4, 2002 compared to 15 wells drilled in Q4, 2003).

- 35 -

Interest expense ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Long-term debt, including bank debt at end of period	$ 38,128	$ 29,358	+ 30%	$ 38,128	$ 29,358	+ 30%
Interest expense	$ 410	$ 531	- 23%	$ 1,749	$ 1,236	+ 42%
As a percentage of production revenue	3%	5%	- 40%	2%	5%	- 60%
Interest expense per boe	$ 1.79	$ 0.86	- 52%	$ 0.95	$ 1.46	- 35%

DEPLETION AND DEPRECIATION

Depletion and depreciation expense increased by 152% in 2003 and by 80% in Q4 compared to their respective periods in 2002. The increase is due to a higher production rate in the year and Q4, 2003. The depletable base was consistent in both years as the capital expenditures, net of proceeds on disposal of properties, were $33 million in 2003 and $ 30 million in 2002.

Depletion and depreciation ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Depletion and depreciation expense	$ 6,236	$ 3,468	+ 80%	$ 23,447	$ 9,306	+ 152%
As a percentage of production revenue	40%	34%	+ 18%	33%	36%	- 8%

Depletion and depreciation expense per boe	$ 13.02	$ 11.70	+ 11%	$ 12.79	$ 10.99	+ 16%

INCOME AND CAPITAL TAXES

The combined federal and provincial income taxes decreased in 2003 to 40.75% from 42.12% in 2002. The actual tax provision recorded on the financial statements is at much lower rates in both 2003 and 2002 (29.32% in 2003 and 17.32% in 2002). The rate was very low in 2002 mainly because of the $3.1 million gain on redemption of preferred shares which was not a taxable gain for tax purposes, resulting in a lower tax provision in that year. The rate was also lower in 2003 mainly due to changes in the timing differences related to the Crown royalties and the resource allowance calculation, and to differences related to the Trust distributions, which are deductible in part for tax purposes but are not deducted to arrive at net earnings.

Income and capital taxes (*in Thousand s except for percentages)*

	Year 2003	Year 2002	*Change*
Income tax expense	$ 2,075	$ 1,043	+ 99%
Combined federal and provincial income tax rate	40.75%	42.12%	- 3%
Actual tax rate as a percentage of net earnings	29.32%	17.32%	+ 71%
Estimated tax pools at December 31			
Canadian oil and gas property expense (COGPE)	$ 11,268	$ 20,148	
Canadian exploration expense (CEE)	$ 8,832	$ 9,870	
Canadian development expense (CDE)	$ 21,297	$ 4,708	
Undepreciated capital cost (UCC)	$ 23,247	$ 27,109	
Other	$ 1,740	$ 2,331	
	$ 66,384	$ 64,166	+ 3%

EARNINGS

Both earnings from operations and net earnings are presented below in order to show the impact of one-time events which occurred in both years. Earnings were higher in 2002 because of the impact of a $3.1 million gain on redemption of preferred shares. The opposite occurred in 2003 as earnings were reduced by the re-organization costs related to the conversion to a trust structure in the fourth quarter of 2003.

- 36 -

Enterra s earnings from operations increased by 341% in 2003 and decreased by 8% in Q4 compared to their respective periods in 2002. The large 2003 increase was caused by increased production (up 117% for the year), higher prices (higher on average by 29% during 2003) and, except for royalties, lower expenses as a percentage of revenue in 2003. The results were similar on a per unit basis, $0.68 per unit in 2003 compared to $0.16 per unit in 2002, for with a 326% increase.

Q4 s earnings from operations were almost identical in each year, despite the higher production in 2003. This is due mainly to lower royalties and lower depletion in 2002. The large loss in Q4 of 2003 is the direct results of the $5.8 million in costs related to the trust conversion.

As mentioned earlier, it is management s view that earnings from operations is a good measure of performance and an appropriate benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events which may otherwise distort the financial results. Earnings from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

Earnings ***(in Thousand s except for per unit/share amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Earnings from operations	$ 1,020	$ 1,108	- 8%	$ 12,835	$ 2,909	+ 341%
Deduct re-organization costs	(5,756)	-		(5,756)	-	
Add back gain on redemption of preferred shares	-	-		-	3,111	
Earnings (loss) before income taxes	$(4,736)	$ 1,108	N/A	$ 7,079	$ 6,020	+ 18%
Deduct income taxes	(367)	(393)		(2,075)	(1,043)	
Net earnings (loss)	$(5,103)	$ 715	N/A	$ 5,004	$ 4,977	+ 1%
Earnings from operations as a percentage of revenue	7%	11%	- 36%	18%	11%	+ 64%
Earnings from operations on a per boe basis	$ 2.13	$ 3.74	- 43%	$ 7.00	$ 3.44	+ 103%

Per unit/share information

Earnings from operations per unit/share	$ 0.05	$ 0.06	- 17%	$ 0.68	$ 0.16	+ 326%
Net earnings (loss) per unit/share	$ (0.25)	$ 0.04	N/A	$ 0.26	$ 0.27	0%
Average number of units/share outstanding	20,205	18,336	+ 10%	18,954	18,309	+ 4%

- 37 -

CASH FLOW FROM OPERATIONS

Cash flow from operations grew by 205% in 2003 and by 54% in Q4 compared to their respective periods in 2002. As a percentage of revenue, cash flow from operations was consistent in both years and both quarters, at 51% of revenue in 2003 compared to 46% in 2002, and 48% of revenue in Q4 of both 2003 and 2002.

Higher production volumes and higher commodity prices in 2003 are the main factors behind the increase. Pricing was not a factor in Q4 because prices actually showed a small decrease of 4% in 2003 compared to 2002.

The changes on a per unit basis showed similar results: an increase of 195% in 2003 compared to 2002 and 40% in Q4, 2003 compared to Q4, 2002.

As mentioned earlier, it is management s view that cash flow from operations is a very useful measure of performance, especially in light of Enterra s conversion to an oil and gas income trust. Cash flow from operations is the key factor in setting the monthly distribution rate. As discussed in the earnings section above, cash flow from operations is also a good benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events which may otherwise distort the financial results. Cash flow from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

Cash flow from operations ***(in Thousand s except for per unit/share amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Net earnings (loss)	$ (5,103)	$ 715	N/A	$ 5,004	$ 4,977	+ 1%
Add back re-organization costs	5,756	-		5,756	-	
Deduct gain on redemption of preferred shares	-	-		-	(3,111)	
Add back depletion and depreciation	6,236	3,468		23,447	9,306	
Add back (deduct) amortization of deferred financing charges	(27)	391		262	391	
Add back future income taxes	323	360		1,941	911	

Deduct amortization of deferred gain	-	(83)		(237)	(524)	
Add back non-cash expense related to value of warrants	282	-		282	-	
Cash flow from operations	$ 7,467	$ 4,851	+ 54%	$ 36,455	$ 11,950	+ 205%
Cash flow from operations as a percentage of revenue	48%	48%	0%	51%	46%	+ 11%
Cash flow from operations on a per boe basis	$ 15.59	$ 16.37	- 5%	$ 19.88	$ 14.11	+ 41%
Per unit information						
Cash flow from operations per unit/share	$ 0.37	$ 0.26	+ 40%	$ 1.92	$ 0.65	+ 195%
Average number of units/shares outstanding	20,205	18,336	+ 10%	18,954	18,309	+ 4%

CAPITAL EXPENDITURES

Capital expenditures, net of disposals, for the year ended December 31, 2003 were $33.3 million (2002 - $30.1 million) and $11.9 million for Q4 (2002 - $20.1 million). Enterra drilled 47 wells in 2003, resulting in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate. Enterra drilled 62 wells (57.7 net) in 2002, resulting in 25 oil wells (23.7 net) and 37 gas wells (34.0 net). There were 15 wells drilled in Q4 of 2003 compared with 54 wells drilled in Q4 of 2002, which is why the capital expenditures in Q4, 2002 are twice as high as Q4, 2003. Proceeds on disposal of oil and gas properties were $18.3 million in 2003 (2002 - $5.8 million). These proceeds used to reduce debt and replenish working capital relate almost exclusively to the sale of the Grand Forks properties, which occurred in the second quarter of 2002 and which accounted for $5.3 million of the total proceeds.

Capital expenditures ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Property acquisitions	$ 73	$ 89		$ 8,539	$ 4,829	
Proceeds on disposal of properties	(2,228)	(410)		(18,263)	(5,810)	
Drilling (exploration and development)	10,048	14,386		28,390	21,519	
Facilities and equipment	4,008	6,027		14,368	9,347	

Other	92	8		286	235	
	$ 11,993	$ 20,100	- 40%	$ 33,320	$ 30,120	+ 11%

CASH DISTRIBUTIONS

Enterra paid distributions of US$0.10 per unit for the month of December 2003 and for the first two months of 2004. The distribution for the month of March 2004 was raised to US$0.11 per unit. Cash distributions are paid on the 15th of the following month (e.g. the March distribution would be paid on April 15).

Enterra's distributions are highly dependent on commodity prices, primarily the price of crude oil. Enterra mitigates this risk by hedging some of its oil production. A detailed schedule of Enterra s hedging history and current position is included in the next section dealing with liquidity and capital resources.

For Canadian tax purposes 72.37% of the December distribution is taxable income to unitholders for the 2003 tax year. The remaining 27.63% is a tax deferred return of capital which will reduce the unitholder's cost base of the unit for purposes of calculating a capital gain or loss upon ultimate disposition of the trust units.

- 38 -

For U.S. tax purposes, the December distribution is a 2004 taxable event. Enterra s distributions are typically dividend income for U.S. unitholders, without any portion deemed a return of capital.

OUTLOOK 2004

Enterra s focus in 2004 continues to be on enhancing value for its unitholders by delivering a stable and growing monthly distribution, combined with a potential for a price appreciation of its trust units in the market place.

Our objectives for 2004 include:

- accretive reserve replacement through property acquisitions with development upside.
- a growing distribution from quarter to quarter.
- controlling and reducing operating costs.
- maintaining an effective development program through farm-out and joint venture arrangements.
- keeping our investors up-to-date with our plans through timely communications. a focus on per unit growth.

LIQUIDITY AND CAPITAL RESOURCES

Enterra s bank debt at December 31, 2003 was $34 million (2002 - $24.4 million). In both periods the funds were used to acquire capital assets and support ongoing operations. At December 31, 2003 Enterra s bank facility consisted of a line of credit of $39.6 million (2002 - $26.7 million). Interest on amounts drawn is based on the bank s prime rate plus 0.25%. Enterra was in full compliance with all of its bank covenants at December 31, 2003

In both 2003 and 2002 Enterra financed its ongoing operations in part by selling properties. Proceeds from such sales were $18.3 million in 2003 and $5.8 million in 2002. As a trust, Enterra is less likely to dispose of properties unless the funds from such sales can be re-invested in acquiring new properties with development upside potential as part of Enterra s reserve replacement strategy.

Enterra s preferred shares were redeemed in 2002 for $2.3 million, paid for with cash of $1.75 million and a note of $550,000. The note was subsequently settled for $325,000, resulting in a gain of $206,181 net of related legal costs.

In 2002 Enterra closed a sale-leaseback arrangement on some of its production and processing equipment for $5 million. The funds were used for the Company s 2002 drilling program. The lease agreement calls for 60 monthly payments of $88,802, with an option to purchase of $1 million on the last day of the 60th month. This arrangement is accounted for as a capital lease. At December 31, 2003 the balance outstanding on all capital leases was $4,168,548 (2002 - $4,921,598).

On January 16, 2004 Enterra entered into a financing agreement whereby Enterra will issue 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$ 16,500,000. Payment will be received pending registration of the units.

These funds will be applied towards the East Central Alberta property acquisition described below.

On January 30, 2004 the Trust closed an acquisition of properties in East Central Alberta for $19,847,000.

On February 20, 2004 the Trust completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11,805,750 (US$10,265,463 net of financing costs). These funds will be used for drilling projects which Enterra began prior to its conversion to a trust.

Capital expenditures should be approximately $5-10 million in 2004 because Enterra, as an income trust, will be distributing approximately 80% of its cash flow through its monthly distributions. Enterra s strategy for growth in 2004 will be focused on property acquisition which will be funded with a combination of additional debt and equity.

Enterra has approximately $66 million in tax pools available at December 31, 2003. (2002 - $64 million)

Enterra had several costless collars and forward contracts in place during the year in order to minimize the volatility in crude oil pricing. Below is a summary of Enterra s hedging operations in 2002 and 2003:

Hedging summary

Description	Quantity	Pricing	Gain (loss) on contract
Oil contract Oct. 1/2000 to Sept 30/2003 (sold in January 2001)	350/650 bbls of oil/day	US$24.15 to US$27.19	$1,680,000
Zero collar from November 1/2001 to April 30/2002	500 bbls of oil/day	Floor US$20 Ceiling US$24	($41,878)
Zero collar from October 1/2002 to March 31/2003	500 bbls of oil/day	Floor US$22 Ceiling US$28	($65,440)

Natural gas contract from Nov 1/2002 to March 31/2003	1,500 mcf of gas/day	C$4.60 per mcf	($486,225)
Natural gas contract from Nov 1/2002 to March 31/2003	1,500 mcf of gas/day	C$4.45 per mcf	($520,200)
Oil contracts from April 1/2003 to December 31/2003	2,000 bbls of oil/day	From US$29.50 to US$29.80	($246,937)
Contracts entered into subsequent to December 31/2003:			
Oil contracts from January 1/2003 to June 30/2004	500 bbls of oil/day	US$26.75 per barrel	
Oil contracts from January 1/2003 to June 30/2004	500 bbls of oil/day	US$26.68 per barrel	
Oil contracts from January 1/2003 to June 30/2004	1,000 bbls of oil/day	C$38.50 per barrel	
Oil contracts from July 1/2004 to December 31/2004	500 bbls of oil/day	C$40.50 per barrel	

As a trust, Enterra will distribute approximately 80% of its available cash flow to its unitholders. Future growth will be financed with a combination of additional trust units and bank debt. Enterra's level of distribution will fluctuate depending on future commodity prices and operating results. The portion of cash not distributed will be used for maintenance capital or to reduce bank debt. Management believes it has sufficient capital at year-end to meet its current requirements.

SENSITIVITIES

We are exposed to all of the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure, as described in notes 12 and 13 to the consolidated financial statements.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. We assess the financial strength of our customers and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

Foreign Exchange Risk

We are exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. Our monthly distributions are also based on a value expressed in U.S. dollars. However, we pay our operating expenses, drilling expenses and general overhead expenses in Canadian dollars. Changes to the exchange rate between U.S. and Canadian dollars can adversely affect us. When the value of the U.S. dollar increases, we receive higher revenue and when the value of the U.S. dollar declines, we receive lower revenue on the same amount of production sold at the same prices. A change of $0.01 in the U.S. to CDN dollar would impact Enterra s earnings by approximately $193,000 and its cash flow by $394,000.

Commodity Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If the WTI oil price were to change by US$1.00 per bbl, the impact on Enterra s earnings would be approximately $869,000 and the impact on Enterra s cash flow would be approximately $1,774,000. If natural gas prices were to change by US$0.50 per mcf, the impact on Enterra s earnings would be approximately $873,000 and the impact on Enterra s cash flow would be approximately $1,781,000.

We periodically use hedges with respect to a portion of our oil and natural gas production to mitigate our exposure to price changes. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits which may be derived from price increases.

Interest Rate Risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2003, we had $34 million of indebtedness bearing interest at floating rates. If interest rate were to change by one full percentage point, the net impact on Enterra s earnings would be approximately $244,000 and the net impact on Enterra s cash flow would be approximately $337,000.

Summarized below are Enterra s sensitivities to various risks, based on its 2003 operations:

Sensitivities	Estimated 2004 impact on:	
	Net Income	Cash Flow
Crude oil US$1.00/bbl change in WTI	$869,000	$1,774,000
Natural Gas US$0.50/mcf change	$873,000	$1,781,000
Foreign Exchange - $0.01 change in U.S. to CDN dollar	$193,000	$394,000
Interest rate 1% change	$244,000	$337,000

RELATED PARTY TRANSACTIONS

There were no related party transactions in 2003 or 2002

OFF BALANCE SHEET ARRANGEMENTS

There were no off balance sheet arrangements in 2003 or 2002.

COMMITMENTS

Enterra has only two ongoing commitments over the next five years, one related to the capital lease and the other related to the rental payments for our office space. The rental payments were $299,132 in 2003 (2002 - $240,255 and 2001 - $167,545). These commitments are outlined below:

	2004	2005	2006	2007	Thereafter 2008
Minimum capital lease payments	$786,889	$809,538	$877,697	$1,702,342	
Rental payments re-office space	460,447	467,717	414,770	309,990	640,920
	$1,247,336	$1,277,255	$1,292,467	$2,012,332	$640,920

Note: The above table does not include any imputed interest, as presented in note 14 of the 2003 financial statements.

- 41 -

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for years beginning on or after July 1, 2003. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. Enterra enters into financial instruments to manage its commodity price risk that do not qualify as hedges under the new accounting guideline. We have elected to not apply hedge accounting to any of our financial instruments. Effective January 1, 2004, we will record the fair value of financial instruments as a liability of $1.0 million on the balance sheet. Future changes in fair value of the financial instruments will be recorded as a gain or loss in oil and gas sales in the income statement.

In December 2002, the CICA approved Section 3110 Asset Retirement Obligations to harmonize Canadian GAAP with Financial Accounting Standards Board Statement No. 143. The section replaces previous guidance on future removal and site restoration costs and is effective for fiscal years beginning on or after January 1, 2004. The asset retirement obligation liability is initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the related asset and is depleted over the useful life of the asset. The liability accretes until the obligation is settled. Prior periods will be restated in accordance with the new standard. We have estimated the December 31, 2003 asset retirement obligation to be $2.2 million, based on a total future liability of $4.2 million.

The CICA issued Accounting Guideline 16, which replaces Accounting Guideline 5, Full Cost Accounting in the Oil and Gas Industry. The guideline is effective for fiscal years beginning on or after January 1, 2004 and is to be accounted for on a prospective basis. The most significant change is the modification of the ceiling test to be consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline limits the carrying value of oil and gas properties to their fair value. There is no write down of our property, plant and equipment under either the old or the new method as of December 31, 2003.

Effective March 31, 2004, the Trust and all reporting issuers in Canada will be subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and Annual Information Form (AIF). The instrument also requires enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to unitholders, but rather these documents will be provided on an "as requested" basis. The Trust continues to assess the implications of this new instrument which will be implemented in 2004.

Other accounting standards issued by the CICA during the year ended December 31, 2003 are not expected to materially impact us.

U.S. Pronouncements

The following standards issued by the FASB do not impact us at this time:

(a) Interpretation No. 46, "Consolidation of Variable Interest Entities", effective for the Trust for the period ending December 31, 2004.

(b) FAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity", effective for financial statements issued after June 15, 2003.

(c) FAS No. 132 (revised 2003), "Employers   Disclosures about Pensions and Other Post Retirements Benefits - an amendment of SFAS No. 87, 88 and 106", effective for financial statements issued after December 15, 2003.

(d) FAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", effective for contracts entered into or modified after June 30, 2003.

The Trust will continue to assess the applicability of these standards in the future.

- 42 -

RESULT OF OPERATIONS 2002 COMPARED TO 2001

OVERVIEW

Enterra achieved record revenue, cash flow and earnings in 2002. Enterra s growth occurred primarily in the fourth quarter of the year when revenue and cash flow doubled from the previous quarter. Enterra exited the year with a production rate of 5,335 boe/day, doubling the previous quarter exit rate of 2,456 boe/day. Enterra continued to reduce operating costs during 2002, resulting in an average cost per boe of $7.11 compared to $8.38 in 2001. Total reserves increased by 36% to 11.08 million boe with the majority of the increase coming from the Clair property. Enterra also strengthened its balance sheet by redeeming a substantial portion of its preferred shares for a gain of $3.1 million.

Summarized financial and operational data ***(in Thousand s except for volumes and per share amounts)***

	Year 2002	Year 2001	*Change*
Exit production rate (boe per day)	5,335	2,675	+ 99%
Average annual production revenue	$ 25,746	$ 20,264	+ 27%
Average annual production volumes (boe per day)	2,320	1,906	+ 22%
Cash flow from operations for the year	$ 11,950	$ 9,810	+ 22%
Cash flow per share for the year	$ 1.31	$ 1.40	- 7%
Earnings *(including $3.1 million gain on redemption of preferred shares in 2002)*	$ 4,977	$ 1,617	+ 208%
Earnings per share for the year	$ 0.54	$ 0.23	+ 134%
Average number of shares outstanding during year	9,154,491	6,992,393	+ 31%
Average price per bbl of oil during year	$ 33.86	$ 30.53	+ 11%
Average price per mcf of natural gas during year	$ 4.08	$ 3.66	+ 11%
Operating costs per boe during year	$ 7.11	$ 8.38	- 15%
General and administrative expenses per boe during year	$ 1.99	$ 0.81	+ 145%

PRODUCTION INCOME

Production income increased by 27% in 2002 from $20.3 million to $25.7 million, mainly due to the accelerated drilling program in effect during the fourth quarter of the year. Enterra drilled only eight wells in the first nine months of 2002 but drilled 54 wells in the fourth quarter alone. Commodity prices were slightly higher, on average, in 2002 than 2001 a 40% decrease.

Enterra drilled 62 wells (57.7 net) in 2002, resulting in 25 oil wells (23.7 net) and 37 gas wells (34.0 net) for a success ratio of 100%. Enterra s production in 2002 averaged 2,320 boe/day, consisting of 1,460 bbls/day of oil and 5,157 mcf/day of natural gas, for a mix of 63% oil and 37% natural gas.

Enterra exited 2002 at a rate of 5,335 boe/day, consisting of 4,205 bbls/day of oil and 6,780 mcf/day of natural gas, for a mix of 79% oil and 21% natural gas. This represents a 99% increase over the 2001 exit rate of 2,675 boe/day.

Production income ***(in Thousand s except for volumes and pricing)***

	Year 2002	Year 2001	*Change*
Crude oil and natural gas liquids	$ 18,075	$ 17,773	+ 2%
Natural gas	7,671	2,491	+ 208%
Total production income	$ 25,746	$ 20,264	+ 27%
Volumes			
Average oil production during year (in bbls/day)	1,460	1,595	- 8%
Average gas production during year (in mcf/day)	5,157	1,863	+ 177%
Average total production during year (in boe/day)	2,320	1,906	+ 22%
Exit oil production (in bbls/day)	4,205	2,065	+ 104%
Exit gas production (in mcf/day)	6,780	3,660	+ 85%
Exit total production (in boe/day)	5,335	2,675	+ 99%
Pricing			
Average price received per bbl of oil during year	$ 33.86	$ 30.53	+ 11%
Average price received per mcf of natural gas during year	$ 4.08	$ 3.66	+ 11%

PRODUCTION EXPENSES

Production expenses increased by 3% from $5.8 million in 2001 to $6 million in 2002. On a per boe basis, Enterra reduced its operating costs by 15% from $8.38 per boe in 2001 to $7.11 per boe in 2002. This trend should continue in 2003 as Enterra focuses its efforts on selected core areas.

Production expenses ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
Production expenses	$ 6,018	$ 5,830	+ 3%
As a percentage of production revenue	23%	29%	- 21%
Production expenses per boe	$ 7.11	$ 8.38	- 15%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, increased by 32% as a result of both the increased production in 2002 and the higher commodity prices in effect durin