ENTERRA ENERGY CORP
Form 10KSB
March 31, 2003

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-KSB

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

OR

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)

For the transition period from to

Commission file number 333-39826

ENTERRA ENERGY CORP.

(Name of Small Business Issuer in Its Charter)

Alberta, Canada	n/a
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

Suite 2600, 500 4th Avenue S.W.

Calgary, Alberta, Canada	T2P 2V6
(Address of Principal Executive Offices)	(Zip Code)

Issuer's Telephone Number: 403/213-2502

Securities registered under Section 12(b) of the Exchange Act:

None

Securities registered under Section 12(g) of the Exchange Act:

Common Stock, $0.001 Par Value

(Title of class)

Check whether the issuer: (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for 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

Check if no disclosure of delinquent filers in response to Item 405 of Regulation S-B is contained in this form, and no disclosure will be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. [x]

The issuer's revenues for the most recent fiscal year were Cdn. $ 25,746,000.

The aggregate market value of the voting and non-voting common equity held by non-affiliates, based upon the average bid and asked prices of the Common Stock on March 25, 2003 was Cdn. $ 45,912,000. Shares of Common Stock held by each officer and director and by each person who owns 5% or more of the outstanding Common Stock have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The number of shares outstanding of the issuer's Common Stock, as of March 25, 2003 was 9,183,325.

ENTERRA ENERGY CORP.

Table of Contents

PART 1	Page
Description of Business	3
Description of Property	15
Legal Proceedings	15
Submission of Matters to a Vote of Security Holders	16
PART II	
Market for Common Equity and Related Stockholder Matters	16
Management s Discussion and Analysis or Plan of Operations	20
Consolidated Financial Statements	31
Changes and Disagreements With Accountants on Accounting and Financial Disclosure	32
PART III	
Directors, Executive Officers, Promoters and Control Persons	32
Compliance with Section 16(a) of the Exchange Act	35

Executive Compensation	35
Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	37
Certain Relationships and Related Transactions	44
Exhibits and Reports on Form 8-K	44
Controls and Procedures	45

Exchange Rate Information

We publish our consolidated financial statements in Canadian dollars. In this annual report, except where otherwise indicated, all dollar amounts are stated in Canadian dollars. References to "$" or "C$" 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 December 31, 2002, the noon buying rate was US$1.00 equals C$1.5769 and the inverse noon buying rate was C$1.00 equals US$0.6344.

	2002	2001	2000	1999	1998	1997
End of period	0.6344	0.6285	0.6669	0.6918	0.6538	0.6996
Average for the period	0.6372	0.6456	0.6732	0.6691	0.6693	0.7207
High during the period	0.6656	0.6714	0.6969	0.6935	0.7124	0.7497
Low during the period	0.6175	0.6227	0.6410	0.6464	0.6311	0.6938

WE ARE REQUIRED TO FILE REPORTS AND OTHER INFORMATION WITH THE SEC UNDER THE SECURITIES EXCHANGE ACT OF 1934. REPORTS AND OTHER INFORMATION FILED BY US WITH THE SEC MAY BE INSPECTED AND COPIED AT THE SEC'S PUBLIC REFERENCE FACILITIES DESCRIBED ABOVE. AS A FOREIGN PRIVATE ISSUER, WE ARE EXEMPT FROM THE RULES UNDER THE EXCHANGE ACT PRESCRIBING THE FURNISHING AND CONTENT OF PROXY STATEMENTS AND OUR OFFICERS, DIRECTORS AND PRINCIPAL SHAREHOLDERS ARE EXEMPT FROM THE REPORTING AND SHORT-SWING PROFIT RECOVERY PROVISIONS CONTAINED IN SECTION 16 OF THE EXCHANGE ACT. UNDER THE EXCHANGE ACT, AS A FOREIGN PRIVATE ISSUER, WE ARE NOT REQUIRED TO PUBLISH FINANCIAL STATEMENTS AS FREQUENTLY OR AS PROMPTLY AS UNITED STATES COMPANIES.

PART I

Item 1.

Description of Business

BUSINESS

History

Enterra Energy Corp. (formerly Westlinks Resources Ltd.)("Enterra") was formed on June 30, 1998 by the amalgamation of Temba Resources Ltd. ("Temba") and PTR Resources ltd. ("PTR") in a share-for-share exchange. The combination was recorded using the purchase method of accounting with Temba being identified as the acquirer. An amalgamation is the consolidation of the two amalgamating companies, and is a continuation of both businesses. Our predecessor, Temba Resources Ltd., was incorporated in Alberta on July 31, 1996 and at the time of the amalgamation had acquired oil and gas production of approximately 27 barrels of oil per day and 106 thousand cubic feet of gas per day from 19 oil wells and one gas well. Immediately prior to the amalgamation which created Westlinks, Temba Resources amalgamated with its wholly owned subsidiary, Rainee Resources Ltd. Our predecessor, PTR Resources, 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 on December 1, 1997. PTR Resources originally held a 2.5% working interest in mineral leases on 8.5 sections of land in Alberta.

Effective August 1, 2001 Enterra acquired 100% of the common shares of Big Horn Resources Ltd. ("Big Horn"), a junior oil and gas company listed on the Toronto Stock Exchange, by the way of a plan of arrangement. Consideration consisted of cash of C$2,205,447 (not including acquisition costs) and the issuance of 3,496,436 common shares and 7,418,332 preferred shares. In addition, approximately 460,915 Enterra options were issued in exchange for Big Horn options.

Effective December 10, 2001 Westlinks Resources Ltd. changed its name to Enterra Energy Corp.

Our Business

We are an operating oil and gas company that drills, acquires, operates and exploits crude oil and natural gas wells in our core areas in Western Canada. Our capital budget for 2003 is approximately C$25 million, subject to available funds, earmarked for development and exploitation programs focused almost exclusively in Alberta, Canada. The magnitude of our 2003 drilling program will depend on the results of our analysis of seismic studies and the results of our previous drilling, and the development of new opportunities as the year progresses.

Glossary of Petroleum Industry Terms

The following definitions of certain terms used in the oil and gas industry will assist you in understanding our business:

"**Developmental Wells**" are wells drilled for oil or gas within a proven field for the purpose of completing the desired pattern of production;

"**Infield and step-out wells**" mean wells that have been drilled either in between or on the outside edge of other nearby producing wells;

"**Non-operated property**" means a well that is managed by a third party;

"**Permeability**" means the ability of a porous rock to transmit fluid through its pore spaces. A rock may be highly porous and yet be impermeable if it has no interconnecting pore network communication;

"**Petrophysical data**" means the rock parameters associated with a reservoir, including thickness, porosity, permeability;

"**Porosity**" means the ability of a rock to contain fluids. It is the volume of pore spaces between mineral grains, expressed as a percentage of the total rock volume;

"**Reservoir**" means a porous, permeable sedimentary rock structure or trap containing oil and/or gas;

"**Spudding**" means the commencement of the drilling of a well;

- 3 -

"**Waterflood**" means the injection of water into an oil reservoir in order to enhance production;

"**Water injection well**" means a well used to inject water into an oil reservoir in order to conduct a waterflood;

"**Wildcat**" means a well drilled in an area where oil and gas has not been previously found; and

"**Working Interest**" means the percent of production, before royalties, to which a party is entitled.

Business Strategy

As a result of the Big Horn acquisition a new management team is in place at Enterra. Big Horn s previous management was the surviving management group following the August 1, 2001 Big Horn acquisition. Prior to 2001, Enterra (then known as Westlinks) was an acquisition driven company. Big Horn, on the other hand, was a full cycle oil and gas producer, focused on exploration and development. The new management at Enterra was more focused in 2002 on its exploration, development and exploitation programs than on corporate or property acquisitions. This strategy will continue in 2003.

Low Risk Development Projects

We concentrate our efforts on oil and gas properties that offer opportunities for low risk development. Typical types of low risk developments are the drilling of infield and step-out wells, the installation of central facilities to handle higher production volumes and the completion of other productive zones within wells.

Consolidation of Adjacent Assets

We seek property acquisitions and development opportunities on lands that are in close proximity to our producing fields. These close-in acquisitions create the ability to reduce operating costs by consolidating facilities. Moreover, drilling costs are lower when wells are drilled as part of a multi-well program, due to reduced rig moving costs and other efficiencies.

Cost Effective Acquisitions

While our main focus is the exploitation and development of our properties, we will pursue acquisitions of oil and gas producing properties but only at prices that allow the base production for the property to pay the acquisition cost within a reasonable time frame. We attempt to avoid paying for unproven reserves in the purchase price.

Emphasis on Development Drilling

We concentrate our drilling activities on low risk development wells located in or near our established core production areas. This strategy helps to reduce risk and costs, and enables new wells to be put on production more quickly. We do engage in exploratory drilling but only when the potential rewards justify the risks involved.

Use of Seismic and Other Data in Site Selection

We use the analysis of seismic data, including three-dimensional seismic, whenever its use is appropriate for the geology and is cost effective, to further minimize drilling risk. We also use information from adjacent wells, including petrophysical data, production records and completion data to help reduce our risk and costs.

Selection of Properties

We select properties for acquisition and development where we believe we can become the operator and that we believe offer us the opportunity to reduce operating costs and maximize economies of scale, thereby improving operating profitability. We have used this strategy in the development of our core areas in Alberta and Saskatchewan, focusing on areas of moderate drilling costs, multi-zone potential, year round accessibility and good gas plant and pipeline infrastructure.

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 the Company s existing production and reserve base. In accordance with the standard practice in the Canadian oil and gas industry, the working interests described below are the percentage ownership of the oil and gas production before payment of royalties.

- 4 -

PEACE RIVER ARCH OF ALBERTA

Clair

The Clair property is located 13 km north of the city of Grande Prairie, Alberta. The Company s assets include a 100% working interest in 4,480 acres of land, 21 producing oil wells and an oil treating facility. Gas is conserved and processed at the Encana Sexsmith gas plant.

Production is primarily from the 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 one Dunvegan oil pool. There are currently 21 oil wells producing a combined 3300 bbls/d of oil and 1.8 mmcf/d of solution gas. Enterra has plans to drill an additional twelve infill wells, three re-drills (due to mechanical problems), and up to three (3) horizontal injection wells. All these wells are expected to be drilled and on stream by April 1, 2003. The Company will be submitting a water flood application shortly thereafter and will be prepared for 100% voidage replacement when approval is granted by the AEUB.

One dually completed Charlie Lake and Halfway gas well located at 13-7-73-5W6 produces combined daily gas of 400 mcf/d. Enterra has a 100% working interest in this well.

Total proved reserves assigned to the Dunvegan are 2,156 mbbls of oil, 1,685 mmcf of gas and 134 mbbls of natural gas liquids. Total proved and probable reserves assigned to the Dunvegan are 3,806 mbbls of oil, 2,115 mmcf of gas and 169 mbbls of natural gas liquids. The probable reserves category contains the incremental reserves and net present value of the water flood. McDaniel and Associates have stated that the additional reserves associated with the water flood would be moved into the proven category in a staged approach. Critical stages include the EUB water flood approval, commencement of injection, achievement of 100% voidage replacement and performance. Total proved reserves assigned to the 13-07-073-5W6 Charlie Lake / Halfway gas well are 359.0 mmcf of gas and 7.18 mbbls of natural gas liquids. Total proved and probable reserves assigned to the 13-07-073-5W6 Charlie Lake / Halfway gas well are 471.5 mmcf of gas and 9.43 mbbls of natural gas liquids.

Enterra owns and operates a central oil treating facility located at 6-18-73-5W6. Gas is also gathered at this facility and compressed to the Encana Sexsmith Gas Plant. Gas transportation and processing fees equate to $0.56/mcf. Clean oil is currently trucked to the La Glace Peace Pipeline Terminal. Trucking and terminal charges are $2.00/bbl and $1.70/bbl, respectively. Enterra is in the process of getting the 6-18 battery directly connected to the Peace Pipeline. This is expected to be in place by June 2003. The Company will eliminate the trucking costs and terminal charges but the crude oil will be subject to a $1.50/bbl pipeline fee (based on delivering 2500 bbls/d).

Worsley East

Enterra has an 87.5% working interest in 11.75 sections of land (two licenses) in the Worsley East area. Enterra has licensed a Montney well at 5-5-87-6W6, which will evaluate the Notikewin, Bluesky, Doig and Montney sands. The Bluesky is the primary zone and is a nine meter thick blanket sand that has gas trapped in structural highs. Bluesky gas wells in the immediate area include 8-1-87-7W6 and 14-15-87-6W6, which have produced 1.9 Bcf and .66 Bcf of gas, respectively. Both wells have gas over water. Enterra has two trade seismic lines and six proprietary seismic lines over the two licenses.

A Doig channel is present to the north at 14-34-87-6W6 and has produced 2.8 Bcf. A Montney sand to the west at 15-5-87-7W6 has produced 1.2 Bcf. Enterra cannot map a Doig channel or the Montney sand at the 5-5 location, however, by drilling 200 meters deeper we will evaluate both zones. The 5-5 location drilled to 1050 meters will validate seven sections and drill through four potential zones. The Granite wash may also be prospective. A well at 4-33-87-7W6 has produced 16 Bcf of gas from the Granite Wash at a depth of 2300 meters. The 4-33 well is fault controlled with throws of greater than 140 meters. Seismic that Enterra has access to, shows basement faulting on Company land with throws of approximately 70 m. The Company intends to re-evaluate the seismic for basement faulting and then either acquire more 2D lines and/or shoot a 3D program over the leads.

Gordondale

The Gordondale property is located 75 km northwest of the city of Grande Prairie, Alberta. The Company s assets include an average working interest of 79% in 6,240 gross acres of land as well as two flowing gas wells, a gas well awaiting tie in and one oil well.

This exploration area is gas prone in up to eight formations ranging from the Doe Creek at depths of less than 200 m to the Debolt formation at a depth of 2450 m. Enterra shot a 3-D seismic program over the area in 2001 and identified several locations with multi zone potential. In early 2002, the first well was drilled, encountering gas potential in the Kiskatinaw, Taylor Flats, Montney and Halfway formations.

Production is currently from the Upper Kiskatinaw and Halfway zones. The three producing wells located at 02/06-01-, 04-17-, and 12-17-79-11W6 were brought on production in the latter half of 2002. The Company s share of current production for the property is 667 mcf/d of gas, 8.2 bbl/d of oil and 7.6 bbl/d of natural gas liquids. The forecast of the Company s share of production from these three wells for 2003, total proved case, is 521 mcf/d of gas, 19.5 bbl/d of oil and 8.4 bbl/d of natural gas liquids. A fourth well, 03/07-16-79-11W6, is currently awaiting tie-in and is forecast to produce 110 mcf/d gas and 1.9 bbl/d natural gas liquids for the final nine months of 2003 (total proved, Company share).

McDaniel and Associates have assigned total proved reserves to Gordondale of 659.1 mmcf of gas, 24.52 mbbls of oil and 11.2 mbbls of natural liquids. Probable reserves were 909.3 mmcf of gas, 33.67 mbbls of oil and 15.45 mbbls of natural gas liquids.

There are several Halfway Pools in the Gordondale area and Enterra has Halfway wells at 7-16-79-11W6, 4-17-79-11W6, and Halfway gas behind casing at 12-17-79-11W6 which is currently producing from the Upper Kiskatinaw zone. Enterra s well at 12-17-79-11W6 has 30 meters of gas charged Montney and 9 meters of net gas pay similar to Encana s well at 7-34-78-11W6. Two meters were perforated and fraced in Encana s well with initial deliverability exceeding 3.5 mmcf/d. The Montney at 7-34-78-11W6 and in the surrounding area, responds as a low permeability sand, which has produced .4 Bcf and is still producing at 600 mcf/d. Two meters of potential gas pay exists at 2196 2198m in Enterra s 12-17-79-11W6 well. Enterra plans to complete the Taylor Flat zone prior to perforating the Montney.

Enterra has two producing Upper Kiskatinaw gas wells at 6-1-79-11W6, and 12-17-79-11W6 and one bypass Upper Kiskatinaw gas well at 10-20-79-11W6. Seismic interpretation of 3D and 2D, have identified anomalies in the northeast corner of 16, the southwest corner of 17, and in the northwest corner of section 20. Gas production from 12-17-79-11W6 is tied into a CNRL Pouce Coupe Gas Plant located at 11-19-79-11W6. All other gas that is currently tied in (6-1-79-11W6) is processed at the Duke Midstream Gordondale West Gas Plant located at 11-26-79-9W6. Oil production from 4-17-079-11W6 is produced to on site tankage and trucked away for treating.

Rolla

The Rolla property is located 70 km north of the city of Grande Prairie, Alberta. The Company 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.

Current gas production is approximately 1 mmcf/d from three Dunvegan gas wells. Enterra has identified two development opportunities in section 15-78-7W6 and section 22-78-7W6. 8-15-78-7W6 has 5m of bypass Gething gas pay at 1320 1325m. The Gething interval has greater than 18% porosity and 50 ohms resistivity, these are better than the key well at 12-13-78-8W6, which has produced 3.5Bcf of gas. Upon completion, the field Engineer reported extremely poor cement bond over the Gething zone to the Calgary office and was told to go ahead and perforate the Gething. Water was recovered after perforating and the Gething zone was abandoned. Section 22-78-7W6 is prospective for Baldonnel gas. 8-16-78-7W6 an abandoned well, produced Baldonnel gas at 2mmcf/d before watering out.

Total proved reserves assigned to the Dunvegan are 1213.0 mmcf of gas and total proved and probable reserves assigned to the Dunvegan are 1414.8 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. Enterra s land, which consists of three sections is developed with three producing gas wells. Enterra has a 12.5% working interest in two compressors located at 8-9-79-7W6. Gas is compressed from this location into the Duke Midstream operated Gordondale East Gas Plant.

- 6 -

EAST CENTRAL ALBERTA

Sounding Lake

The Sounding Lake package is located 10 km southwest of the town of Provost, Alberta. The Company s assets include an average working interest of 67.5% in 5,316 gross acres of land as well as 48 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. The Company s share of current production for the entire area is 700 bbls/d of oil and 1,600 mcf/d of gas. Enterra completed an optimization program in the Sounding Lake area in mid 2002 by commingling the Dina and Cummings production where applicable, upgrading pump sizes to maximize oil production and upgrading oil batteries to handle higher volumes of total fluid and injection water.

The Company has budgeted several more capital projects for 2003 that are expected to add up to 320 bbls/d of oil and 300 mcf/d of associated gas production. These projects includes six infill drilling locations at Sounding Lake North. All of the wells are defined from geological mapping and 3-D seismic. Enterra was assigned proved reserves at Sounding Lake of 1,115.8 mbbl of oil and 1,393.8 mmcf of natural gas. In recognition of the Company s 2002 optimization program in the area, probable reserves were also assigned for an expected performance enhancement.

Total proved and probable reserves are 1,372.8 mbbl oil and 1,597.6 mmcf natural gas.

Enterra has budgeted $900,000 for the drilling of six wells at Sounding Lake North and $240,000 (gross) for the tie in of solution gas at Sounding Lake West and East. Enterra operates a central oil treating battery at both Sounding Lake West (11-27-37-4W4; 50.7% working interest) and Sounding Lake East (05-31-037-3W4; 100% working interest). These facilities were recently optimized to handle larger volumes of produced water resulting from the 2002 optimization program. Both of these areas are also equipped water injection facilities.

At Sounding Lake North, all of the production is gathered to a central location, where it is metered and flowlined to a major nearby oil treatment facility operated by Calpine Canada. Enterra owns a 3-D seismic program over the Sounding Lake North field. This 3-D seismic was recently used to identify six infill drilling locations for 2003. The company controls a large percentage of the mature Dina PPP and T4T pools at Sounding Lake East and West. The Dina Reservoir is a braided marine sand bar type. With numerous stacked bar sands in succession surrounded and trapped by intermittent shales and regionally tight non-channel Dina facies. Average net pay per well is 4-5m, with good porosities of around 26%. The Lloydminster formation is of reservoir quality though no evidence of hydrocarbon trapping has been found within the Company lands. Enterra s land at Sounding Lake North consists of a number of oil producing Mannville sands. The Dina formation is locally productive from the braided fluvial bar type sands, as well as well developed extra-fluvial sands in the regional facies. The Cummings formation is a regionally developed near marine sand that is locally cut by a later time channel event causing traps to form and large volumes of oil to accumulate. Development potential also occurs in the Lloydminster, which pinches out trapping oil to the northwest, as well as a thick Rex channel that cuts through the lands.

CENTRAL ALBERTA

Sylvan Lake

The property currently produces 300 bbls/d (gross), 225 bbls/day (net) of 16 degree API oil from 7 wells. Production is gathered at individual well sites and trucked to third party facilities for treating. In conjunction with Enterra s plan to drill infill wells at 40 acre spacing is the installation of a Company owned and operated oil treating facility which will substantially drop operating expenses. Infill wells are expected to average initial deliverability of 75 bbls/d per well.

McDaniel and Associates has assigned total proved reserves of 514.33 mbbls of oil and 96.8 mmcf of non-associated gas. Total proved and probable reserves are 811.66 mbbls of oil and 157.0 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. Non-associated gas volumes are assigned to the 13-21-038-02W5 Viking gas well that produces into the nearby Husky operated Sylvan Lake Gas Plant. Enterra is planning to down space the Sylvan Lake Pekisko to 10 acres, depending on the success of the 40 acre infill program. This 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

The Kaybob 12-14-058-17W5 horizontal oil well is capable of producing in excess of 500 bbls/d of light crude oil and 0.5 mmcf/d of associated gas. The well is currently shut in until June 2003 as the gathering system, operated by Chevron Canada, is undergoing intensive corrosion inspection and repair. Because of this unscheduled and lengthy downtime, Enterra has taken the opportunity to conduct a cement squeeze operation in the structurally low and wet heel area of the horizontal. The cement squeeze operation will be tested in June 2003 but should be effective in eliminating any produced water.

McDaniel and Associates have assigned total proved reserves to the 12-14-058-17W5 horizontal oil well of 513.58 mbbls of oil, 654.8 mmcf of gas and 13.09 mbbls of natural gas liquids. Total proved and probable reserves are 698.78 mbbls of oil, 890.90 mmcf of gas and 17.82 mbbls of natural gas liquids. Enterra acquired its interest in the Kaybob South Nisku C Pool in the year 2000. 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. Reef production stopped in 1995 after a single, vertical well at 6-14-58-17W5, watered out after producing 400,000 bbls of oil. Although the vertical producer watered out when produced at commercial quantities, at rates less than 30 bbls/d the well continued to produce clean oil. Enterra acquired and reprocessed a 3-D seismic program covering the entire reef. The new interpretation indicated that reef porosity grew at least 7 meters higher than the porosity encountered in the vertical well. This was a strong indicator that significant quantities of attic oil reserves remained in the structurally higher portion of the reef. To exploit these reserves with the highest possible recovery factor, Enterra drilled a horizontal well accessing the top of the reef. This operation was conducted in early 2001 and was executed by kicking out of the existing vertical producer. Horizontal drilling was terminated approximately 340 m from the vertical well with a gain in porosity structure of 7 m. The 12-14-58-17W5 Hz well was deliverability tested in June 2001. Results of this test indicated the well would initially be produced into the flowline at a restricted rate of 500 bbls/d with a 30% water cut.

Early in 2002, Chevron Canada notified Enterra that third party production, utilizing their gathering system, would be shut in due to corrosion identified from pipeline inspection. Although this corrosion was not from Enterra s production Chevron wanted to eliminate the possibility of third parties having responsibility for any failures that could have resulted. Chevron also notified The Company that the earliest it could bring its production back on line is in June 2003, after a major turnaround at the Chevron K3 Gas Plant. Chevron has planned a significant gathering system inspection and repair program during this turnaround. Despite continued efforts to bring the well back on stream, Chevron has insisted that the earliest this would occur will be after the gathering system, that Enterra uses, gets inspected and repaired in May 2003.

Realizing that the Kaybob 12-14 Hz well will be shut in for an extended duration prompted Enterra to design a workover to eliminate the water production. Decreasing the water cut would allow the well to flow at higher pressures and it would also reduce operating costs. The Company conducted a successful, bull head cement squeeze operation on August 10, 2002, which was designed to place a cement plug across the structurally low heel of the horizontal. Unfortunately, Enterra is not able to evaluate the decrease in water cut until the gathering system becomes operational in June 2003. Enterra owns a 90% working interest in 320 acres of land, subject to a 7.5% NCORR on 100% of production. The Company has a licensed copy of a 7 square mile 3-D program over the 12-14 horizontal well and adjacent lands.

OHER PROPERTIES

Bindloss

Enterra selectively fracture stimulated up to five gas bearing sands in the Milk River formation and one in the Medicine Hat. Although the clean up period for this type of stimulation is longer due to greater quantities of water introduced into the formations, the benefit is higher long term production and reserves. The Bindloss field is currently producing 0.5 mmcf/d of gas during the cleanup phase of development. This phase is dominated by stimulation water slowly flowing back into the wellbore. Water will continue to restrict the true potential of each well until the majority of this fluid is produced back. As the water starts to dissipate the gas rate in each well will increase until its full potential is realized. Enterra expects the cleanup phase for the field to last until June 2003.

Beyond this date, The Company expects each well to produce at an average gas rate of 80 mmcf/d. Total field production is expected to peak at 2.3 mmcf/d from 30 wells. Reserves currently assigned to Bindloss are total proved of 1, 230.0 mmcf and total proved plus probable of 1888.3 mmcf. Enterra expects these values to substantially increase as the wells unload water and gas rates accelerate. No capital will be spent on additional drilling until such time as the current wells demonstrate their true productivity potential. The second stage of development consists of the full cycle development of an additional 30 gas wells for a total cost of $5.3MM. This project is expected to start in Q3, 2003.

Enterra owns and operates the only compression, dehydration and gathering system in the Bindloss area, north of the South Saskatchewan River. This will undoubtedly be a source of revenue in the future as other operators will pay Enterra fees for use of this infrastructure. Gas is compressed into the nearby Nova gas pipeline system. Medicine Hat and Milk River Formations blanket the area in thick interlaminated and interbedded sandstones, siltstones and shales. Net pay is determined by a gas neutron log response and gamma ray log cleanliness. Enterra acquired a shut in Waseca oil pool in Southwest Saskatchewan for $2.8 million in June of 2001. The Company equipped and reactivated four existing producers. Combined gross production from these wells is 250 bbls/day. Late in 2001, Enterra added four Waseca infill oil wells.

- 8 -

Deer Mountain

Enterra has a 50%, non-operated, working interest in the 10-24-70-12W5 well. Producing from a westward extension of the Beaver Hill Lake C Pool, 10-24 consistently achieves its maximum rate limitation (MRL) of 63 bbls/d (10 m3/d) each month. Production is flat due to pressure support from the Beaver Hill Lake C Pool water flood. Total proved reserves are 106.62 mbbls of oil and total proved and probable reserves are 128.31 mbbls of oil. Enterra has also purchased a 100% working interest in the south half of section 24 by way of a crown land sale. Two potential infill drilling locations are present on these lands at 160 acre spacing. These lands were not evaluated for potential by McDaniel and Associates. Enterra also bid unsuccessfully on the NW/4 of Sec 24.

Ricinus

The Ricinus D3-A Pool is located approximately 80 kilometres west of Red Deer, 24 kilometres south of the Keyspan Strachan Gas Plant. The pool encompasses sections 17, 18 and 19 of land located in Township 35, Range 8 and section 24 in Township 35 Range 9 W5M. The Ricinus D3-A Pool contains approximately 6,957 E6m^3 (245.7 BCF) of Original Gas In-Place. Currently the pool is abandoned, having removed only 43% of the Original Gas In-Place. The pool resides in the Ricinus Reef Complex; whereby the other analogous pools in the area have achieved gas recoveries averaging 75% and are still producing.

An engineering feasibility study has been conducted on the Ricinus D3-A Pool with positive economic results. The results indicate approximately 22 BCF of sales gas and 62,000 bbls of natural gas liquids can be further recovered. This is a conservative recovery value based off a reservoir model with no attic gas. The reservoir gas is subject to a shrinkage of approximately 35% due to the acid gas content, and 10.16 m^3/Em^3 (1.8 bbls/mmcf) of natural gas condensate is liberated when processed. These recovery values are based on a new well completed into the uppermost section of the D3-A zone (4 metres penetration) with an offset of 250 metres from the existing 11-17-35-8W5M wellbore. This infill location follows the analogous pools production practices. The production profile for the proposed well is a sustained rate of 11 mmcf/d until 2011; at this time the well experiences water break-through and is shut-in. Sensitivities were conducted on offset distance from the 11-17 well bore, depth of penetration into the D3-A zone, potential structural lows, production rate, and cross flow within the original well bores. Confidence in the reserve value is rated as very high due to the production performance and the simulation model.

NEW PROSPECTS

One of Enterra s most valuable asset is its inventory of future projects. The development of these prospects has the potential to significantly increase the size of the Company s existing production and reserve base. New prospects are constantly added to our inventory in order to maintain our growth from year to year. The Company s strategy is to maintain a balanced inventory of exploration and development prospects.

Reserves and Present Value Summary

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 January 1, 2003 prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"), independent petroleum engineers of Calgary, Alberta.

The following table is based on the McDaniel report that shows 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 constant 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 in preparing the report. In the absence of such information, McDaniel relied upon their opinion of reasonable practice in the industry. The McDaniel report 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.

Enterra Energy Corp.

Estimated Petroleum and Natural Gas Reserves and Net Present Value

January 1, 2003

Oil & NGL s		Natural Gas		NPV
Gross	Net	Gross	Net	

	Mstb	Mtsb	MMcf	MMcf	0%	10%	15%
Proved Developed	4,442.7	3,615.3	10,929.6	8,576.7	173,625	133,367	120,823
Proved Developed Non-Producing	77.8	51.9	1,531.6	1,290.6	6,778	3,407	2,589
Proved Undeveloped	1,282.5	943.6	825.8	598.9	34,363	28,283	26,019
Total Proved	5,803.0	4,610.8	13,287.0	10,466.2	214,766	165,057	149,431

Notes:

(1) Definitions:

"*ARTC*" means the Alberta Royalty Tax Credit.

"*NGL*" means natural gas liquids.

"*Gross*" means the total of Enterra s working interest share of reserves before deduction of Royalties.

"*Mbbl*" means thousands of barrels.

"*Mmcf*" means millions of cubic feet.

"*Net*" means gross reserves after deduction of Royalties. In order to estimate reserves after giving effect to the deduction of provincial royalties, certain assumptions must be made including forecasts of future prices and production. The net reserves are based on forecasts by Sproule Associates of these and other factors necessary to estimate provincial and other royalties.

"*Oil*" means crude oil.

"*Proved oil and gas reserves*" are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

"*Proved developed oil and gas reserves*" are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included. Only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"*Royalties*" means royalties paid to others. The royalties deducted from the reserves are based on the percentage royalties calculated by applying the applicable royalty rate or formula. In the case of Crown (the federal or provincial governments in Canada) sliding scale royalties which are dependent on selling price, the price forecasts for the individual properties in question have been employed.

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10 -

"*Sales Gas*" means natural gas which is produced for commercial sale.

(2) The commodity prices used in the McDaniel report are based on actual field prices in effect at December 31, 2002. These prices are being held unescalated throughout the term of the report. A summary of the constant prices used in the McDaniel report are shown below.

Crude oil		**Natural Gas Liquids (C$/bbl)**	
West Texas Intermediate (US$/bbl)	$31.23	Propane	$26.20
Edmonton Light Crude (C$/bbl)	$49.78	Field butane	$29.00
Bow River Medium Crude (C$/bbl)	$41.00	NGL mix	$31.12
Hardisty Heavy (C$/bbl)	$34.00	Natural Gasolines & Condensate	$46.82

Natural Gas (C$/Mmbtu)	
Alberta Average	$5.20
Transcanada Gas Services Ltd.	$5.19
Pan Alberta Gas Ltd.	$4.51
Progas	$5.36
Spot Sales	$5.82
Saskatchewan Average	$5.06
Can West Plant Gate (B.C.)	$4.24

Historical Reserves

The following table sets out Enterra s proved oil and gas reserves at December 31, 2002, 2001, 2000, 1999, 1998 and 1997 respectively. The amounts for December 31, 2001 are based upon a report prepared for Enterra by McDaniel at January 1, 2002. The monetary amounts are expressed in Canadian dollars. The reserve numbers for December 31, 1998 and 1997 were prepared internally by Enterra, based upon reserve reports prepared at various dates by independent engineering firms and adjusted for actual production. Present value amounts are not available as it is not feasible to redo such calculations after the fact.

	December 31,					
	2002	2001	2000	1999	1998	1997
Proved Producing Reserves:						
Oil and NGL s (mbbls)	4,443	3,431	1,612	1,054	588	560

Gas (mmcf)	10,930	7,684	713	107	417	2,957
Proved Reserves:						
Oil and NGL s (mbbls)	5,803	4,133	2,331	1,539	604	560
Gas (mmcf)	13,287	10,707	976	617	417	5,873

Land Holdings

At December 31 Enterra had the following land holdings

	2002	2001
Developed acres (net)	28,355	22,646
Undeveloped acres (net)	51,581	58,590
Total acres (net)	79,936	81,236

- 11

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Production

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

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

Definitions:

"*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):

	2002	2001	2000	1998
Wells drilled	Gross (Net)	Gross (Net)	Gross (Net)	Gross (Net)
Oil	25 (23.7)	9 (4.97)	9 (8.26)	0 (0.00)
Natural Gas	37 (34.0)	8 (3.78)	2 (1.27)	0 (0.00)
Abandoned	0 (00.0)	3 (1.84)	2 (1.14)	1 (0.13)
Total	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:

	Years ended December 31,					
	2002	2001	2000	1999	1998	1997
			(In thousand s)			
Property acquisitions (net)	$ 383	$52,374	$ 8,220	$ 1,879	$ 244	$ 500
Drilling (exploration and development)	21,090	5,821	6,922	341	27	50
Facilities	9,347	1,412	56	728	4	0
Miscellaneous	235	1,011	156	24	2	34
Total	$ 30,289	$68,618	$ 15,354	$2,972	$ 277	$ 584

Oil and Gas Wells

The following table summarizes Enterra s interest in producing and non-producing oil and gas wells as at December 31, 2002 :

PROPERTY	PRODUCING OIL WELLS GROSS	PRODUCING OIL WELLS NET	PRODUCING GAS WELLS GROSS	PRODUCING GAS WELLS NET
Saddle Hills	-	-	5	1.77
Highvale	-	-	2	0.75
West Gull Lake	4	3.60	-	-
Hazlet Unit	8	1.60	-	-
Lanaway	6	2.68	9	3.56
Leduc	1	0.39	-	-
Crossfield	-	-	6	0.16
Cygnet	-	-	2	1.50
Deanne	-	-	2	0.20
Garden Plains	-	-	1	0.62
Gilby	-	-	1	0.39
Leedale	-	-	1	0.02
Lubicon	1	0.23	-	-
Progress	-	-	1	0.50
Sinclair	-	-	1	0.44
Webster	-	-	1	0.25
St. Anne	-	-	2	1.22
Willesden Green	-	-	1	0.43
Worsley	2	1.50	-	-
Mitsue	8	8.00	-	-
Timber Draw	1	0.15	-	-
Sounding Lake East	16	15.50	-	-

Sounding Lake West	55	27.50	-	-
Sounding Lake North	22	6.92	-	-
Sylvan Lake	13	11.75	1	0.32
Clair	21	21.00	5	5.00
Bindloss	-	-	25	25.00
Gordondale	1	0.50	2	1.00
Rolla	-	-	2	1.00
Superb	9	6.12	-	-
Swan Hills	1	0.50	-	-
Campbell	1	0.12	-	-
TOTAL WELLS	170	108.06	70	44.13

Employees

At December 31, 2002 the Company had approximately thirty employees and consultants working both in the Calgary head office and in its field operations.

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 that 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.

Item 2.

Description of Property

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$28.39 per square foot (including operating costs and property taxes).

Item 3.

Legal Proceedings

The Company is not a party to any other pending legal proceedings that management believes could have a material adverse effect on its financial position. There can be no assurance, however, that third parties will not assert infringement or other claims against us in the future, which, regardless of the outcome, could have an adverse impact on the Company as a result of defense costs, diversion of management resources and other factors.

- 15 -

Item 4.

Submission of Matters To a Vote of Security Holders

There have been no matters submitted to a vote of security holders during the fourth quarter of the year ended December 31, 2002.

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PART II

Item 5

. **Market For Common Equity and Related Stockholder Matters**

Price Range of Common Stock and Trading Markets

Our shares of common stock commenced trading on the Canadian Venture Exchange ("CVE") under the symbol "WLX" during the quarter ended September 30, 1998. Our shares of common stock traded on the National Quotation Bureau's pink sheets ("Pink Sheets") under the symbol "WLKSF" from April 26, 2000 to January 10, 2001 when the shares of common stock commenced trading on the NASDAQ SmallCap Market. The shares currently trade under the symbol "EENC" on the NASDAQ SmallCap Market and under the symbol "ENT" on the TSX Venture Exchange ("TSX"). The following table sets forth the bid prices, in Canadian and U.S. dollars, as reported by the TSX and NASDAQ SmallCap Market /pink sheets, for the periods shown.

	TSX Venture Exchange (Cdn. $ s)		NASDAQ SmallCap Market/Pink Sheets (U.S. $ s)	
Five most recent full fiscal years:	High	Low	High	Low
Year ended December 31, 2002	11.50	2.60	7.50	1.47
Year ended December 31, 2001	7.50	2.30	4.81	1.65
Year ended December 31, 2000	7.80	4.45	4.61	3.41
Year ended December 31, 1999	1.05	0.41	n/a	n/a

Year ended December 31, 1998	0.65	0.21	n/a	n/a
Year ended December 31, 2002:				
Quarter ended December 31, 2002	11.50	6.00	7.50	3.80
Quarter ended September 30, 2002	6.45	4.6	4.19	2.95
Quarter ended June 30, 2002	5.49	4.27	3.48	2.25
Quarter ended March 31, 2002	4.96	2.60	2.33	1.47
Year ended December 31, 2001:				
Quarter ended December 31, 2001	3.75	2.30	2.39	1.65
Quarter ended September 30, 2001	5.00	2.75	3.40	1.75
Quarter ended June 30, 2001	6.45	4.70	4.25	2.78
Quarter ended March 31, 2001	7.50	5.00	4.81	3.22
Year ended December 31, 2000:				
Quarter ended December 31, 2000	7.80	5.50	5.15	3.81
Quarter ended September 30, 2000	7.50	6.50	5.10	3.50
Quarter ended June 30, 2000	7.05	4.45	4.79	3.41
Quarter ended March 31, 2000	4.60	4.45	n/a	n/a
Year ended December 31, 1999:				
Quarter ended December 31, 1999	1.05	0.58	n/a	n/a
Quarter ended September 30, 1999	1.18	0.41	n/a	n/a
Quarter ended June 30, 1999	1.70	0.70	n/a	n/a
Quarter ended March 31, 1999	1.50	0.50	n/a	n/a
Six most recent calendar months:				
Month ended December 2001	3.14	2.30	1.86	1.65
Month ended November 2001	3.20	2.68	2.05	1.72

Month ended October 2001	3.75	2.80	2.39	1.78
Month ended September 2001	3.80	2.75	2.50	1.75
Month ended August 2001	4.85	3.30	2.97	2.36
Month ended July 2001	5.00	5.00	3.41	2.75

Number of Holders of Common Stock

At December 31, 2002 there were approximately 42 stockholders of record of the Company's Common Stock. Based on information obtained from the Company's transfer agent, the Company believes that the number of beneficial owners of its Common Stock is approximately 1,517.

Dividends

The Company has never paid cash dividends on its Common Stock. The Company currently intends to retain earnings for use in its business and, therefore, does not anticipate paying cash dividends on its Common Stock in the foreseeable future.

Recent Sales of Unregistered Securities

None

Description of Securities

The authorized capital stock of Enterra consists of an unlimited number of shares of common stock and an unlimited number of shares of preferred stock without nominal or par value. The preferred stock may be issued in one or more series as determined by the board of directors.

Common Stock

Each holder of record of common stock is entitled to one vote for each share held on all matters properly submitted to the stockholders for their vote, except matters which are required to be voted on as a particular class or series of stock. Cumulative voting for directors is not permitted.

Holders of outstanding shares of common stock are entitled to those dividends declared by the board of directors out of legally available funds. In the event of liquidation, dissolution or winding up of the affairs of Enterra, holders of common stock are entitled to receive, pro rata, the net assets of Enterra available after provision has been made for the preferential rights of the holders of preferred stock. Holders of outstanding common stock have no preemptive, conversion or redemption rights. All of the issued and outstanding shares of common stock are, and all unissued shares of common stock, when offered and sold will be, duly authorized, validly issued, fully paid and non-assessable. To the extent that additional shares of common stock may be issued in the future, the relative interests of the then existing stockholders may be diluted.

Normal Course Issuer Bid

Enterra filed a notice in August 2001 to purchase up to 5% of its common shares for cancellation. Enterra had 5,673,639 issued and outstanding common shares at the time. Enterra would buy back its common shares through the facilities of the NASDAQ during the twelve month period commencing on August 20, 2001 and ending on August 20, 2002. Enterra repurchased 232,500 common shares during 2001 and 18,808 during 2002 under this bid.

Preferred Stock

Our board of directors is authorized to issue from time to time, without stockholder authorization, in one or more designated series, unissued shares of preferred stock with such dividends, redemption, conversion and exchange provisions as may be provided by the board of directors with regard to such particular series. Any series of preferred stock may possess voting, dividend, liquidation and redemption rights superior to those of the common stock.

The rights of the holders of common stock will be subject to and may be adversely affected by the rights of the holders of any preferred stock that we may issue in the future. Our issuance of a new series of preferred stock could make it more difficult for a third party to acquire, or discourage a third party from acquiring, the outstanding shares of common stock of Enterra and make removal of the board of directors more difficult.

- 17 -

Enterra issued 7,418,336 Series 1 preferred shares pursuant to the acquisition of Big Horn.

On March 26, 2002 the Company purchased 6,123,870 of its Series 1 preferred shares for $2.3 million, resulting in a gain on redemption of $2,905,290. The purchase was paid for with cash of $1,750,000 and a note payable of $550,000. This note was repaid for $325,000 on August 15, 2002 resulting in an additional gain, net of legal costs, of $206,181.

At December 31, 2002 there were 749,047 Series 1 preferred shares outstanding (December 31, 2001 7,418,336). These shares are non-voting. They are transferable. Subsequent to August 16, 2002 holders of these shares are entitled to receive a fixed cumulative dividend of $0.085 per share per annum, payable quarterly. These shares are redeemable at any time by the Company for $0.85 per share. Holders of these shares may require the Company to redeem all or any of these shares, at $0.85 per share. There is no market for these shares and none is expected to develop.

A dividend of $22,549 was paid on the preferred shares in 2002. This amount is included in interest expense.

Warrants

Warrants entitle the holder to purchase one share of common stock at an stipulated price for a defined period of time. The warrants were issued under the terms of a warrant trust indenture between Enterra and Montreal Trust Company of Canada, as trustee for the warrant holders. Enterra has authorized and reserved for issuance the shares of common stock issuable on exercise of the warrants.

The warrant exercise price and the number of shares of common stock that may be purchased upon exercise of the warrants are subject to adjustment in the event of:

a stock dividend on the common stock;

a subdivision of the common stock;

a split of the common stock;

a reorganization of the common stock

a merger of Enterra with or into another corporation; or

a sale of common stock at a price which is discounted greater than 10% to the market price at the time the company approves the sale.

Enterra must have on file a current registration statement with the SEC pertaining to the common stock underlying the warrants for a holder to exercise the warrants. In the absence of an exemption, shares of common stock underlying the warrants must also be registered or qualified for sale under the securities laws of the states in which the warrant holders reside. We intend to use our best efforts to keep the registration statement presently underlying the warrants current. If the registration statement is not kept current, or if the common stock underlying the warrants is not registered or qualified for sale in the state in which a warrantholder resides, the warrants may not be exercised.

The warrants do not confer upon the warrant holder any voting or other rights of a stockholder of Enterra.

On January 17, 2001, Enterra completed a public offering in the United States. The offering consisted of 1,000,000 units of one common share and one share purchase warrant for U.S. $4.55 per unit. The share purchase warrants were exercisable at U.S. $3.50 per share. They expired unexercised on May 17, 2002. In addition, 100,000 share purchase warrants related to the underwriters agreement were issued and are exercisable at U.S. $5.40 per share starting January 16, 2002 and may be exercised for a four year period thereafter.

On March 28, 2002 the Company agreed to issue 300,000 share purchase warrants to an arm s length U.S.-based consulting firm in connection with a potential debt financing in the United States. The warrants are to have a two-year term and are subject to different pricing (100,000 warrants at US$2.60, 100,000 at US$3.30 and 100,000 at US$4.00). The US$2.60 warrants have vested since the execution in May 2002 of a non-binding letter of intent relating to the proposed financing. The US$3.30 and US$4.00 warrants are to vest only on the successful closing and funding of the proposed financing. A value of $125,000 was assigned to the 100,000 warrants at US$2.60. This value was determined using the Black Scholes Option Pricing model using an interest rate of 5% and a volatility factor of 50%. The $125,000 was credited to the Company s contributed surplus account.

Shares Eligible for Future Sale

Future sales of substantial amounts of our common stock in the public market, in either Canada or the United States, or even the perception that such sales could occur, could adversely affect the market price for our common stock and could impair our future ability to raise capital through an offering of our equity securities.

Enterra currently has outstanding 9,183,325 shares of common stock, assuming no exercise of outstanding warrants and options. These shares are freely tradable, without restrictions imposed by applicable securities laws.

We intend to register the shares of our common stock issuable pursuant to our stock option plan. At December 31, 2002 there were outstanding under the plan options to purchase 871,703 shares, all of which would be eligible for immediate resale in Canada, and in the United States by persons who are not affiliates of Enterra.

Our affiliates may reoffer and resell shares of our common stock in Canada, in accordance with the foregoing, provided that such shares are offered and sold by them pursuant to Rule 903 of Regulation S under the Securities Act and that at the time the TSX Venture continues to be the principal market for our common stock.

Memorandum and Articles of Association

Enterra is incorporated in Canada (corporation number 207913385). The Articles of Amalgamation and by-laws provide no restrictions as to the nature of the business operations of Enterra.

The governing legislation requires a director to inform the Company, at a meeting of the Board of Directors, of any interest in a material contract or proposed material contract with the Company. No director may vote in respect of any such contract made by them with the Company or in any such contract in which they are interested, and such director shall not be counted for purposes of determining a quorum. However, these provisions do not apply to (i) an arrangement by way of security for money lent to or obligations undertaken by them: (ii) a contract relating primarily to their remuneration as a director, officer, employee or agent of the Company or an affiliate: (iii) a contract for indemnity or insurance of the director as allowed under the governing legislation: or (iv) a contract with an affiliate.

The Board of Directors may exercise all powers of the Company to borrow or raise money, and to give guarantees, and to mortgage or charge its properties and assets, and to issue debentures, debenture stock and other securities, outright or as security for any debt, liability or obligation of the Company or any third party.

There are no age limit requirements regarding retirement of directors and there is no minimum share ownership required for a director s election to the board.

Enterra is authorized to issue an unlimited number of common and preferred shares. See "Item 10 A Share Capital." The shareholders have no rights to share in Enterra s profits, are subject to no redemption or sinking fund provisions, have no liability for further capital calls and are not subject to any discrimination due to number of shares owned.

By not more than 50 days or less than seven days in advance of a dividend, the board may establish a record date for the determination of the persons entitled to such dividend. Any dividend unclaimed after a period of six years from the record date shall be forfeited and revert to Enterra.

All directors are elected at each annual meeting of Enterra and cumulative voting is not permitted.

The rights of common shareholders can be changed at any time in a shareholder meeting where the modifications are approved by 66 2/3% of the shareholders represented by proxy or in person at the meeting.

All common shareholders are entitled to vote at annual or special meetings of shareholders, provided that they were shareholders as of the record date. The record date for shareholder meetings may precede the meeting date by no more than 50 days and not less than 21 days, providing that notice by way of advertisement is given to shareholders at least seven days before such record date. Notice of the time and place of meetings of shareholders may not be less than 21 or greater than 50 days prior to the date of the meeting.

There are no:

limitations on share ownership,

provisions of the Articles of Amalgamation or by-laws that would have the effect of delaying, deferring or preventing a change of control of Enterra,

by-law provisions that govern the ownership threshold above which shareholder ownership must be disclosed, and conditions imposed by the Articles of Amalgamation or by-laws governing changes in capital, but the governing legislation requires any changes to the terms of share capital be approved at a meeting of the shareholders affected by the change by 66 2/3% of the shareholders represented by proxy or in person at such meeting.

Item 6. Management's Discussion and Analysis or Plan of Operation

SUMMARY CONSOLIDATED FINANCIAL DATA

The following table presents a summary of our consolidated statement of operations derived from our financial statements for 2002, 2001, 2000 and 1999. The monetary amounts in the table are based on Canadian general accounting principles ("Canadian GAAP"). The 2000 and 1999 results have been restated to reflect the change in its method of accounting for petroleum and natural gas properties from the "successful efforts" method to the "full costs" method. 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 10-KSB .

Consolidated statements of operations data:

(In thousand s, except per share data)

	2002	2001	2000	1999
	C$	C$	C$	C$
Net revenue	$ 25,746	$ 20,264	$ 16,700	$ 2,515
Royalties, net of ARTC	4,203	3,182	3,310	442
Production expenses	6,018	5,830	4,030	782
General and administrative expenses	1,683	565	1,391	863
Interest	1,236	589	833	132
Amortization of deferred charges	391	-	-	-
Depreciation and depletion	9,306	6,870	2,960	705
	22,837	17,036	12,524	2,924
Earnings (loss) from operations	$ 2,909	$ 3,228	$ 4,175	($ 408)
Net earnings (loss) for the year	$ 4,977	$ 1,617	$ 2,453	($ 249)

Basic earnings (loss) per share	$ 0.54	$ 0.23	$ 0.55	($ 0.10)

The following table indicates a summary of our consolidated balance sheets as of December 31, 2002, 2001 and 2000. The monetary amounts in the table are based on Canadian GAAP. The 2000 results have been restated to reflect the change in its method of accounting for petroleum and natural gas properties from the "successful efforts" method to the "full costs" method.

Consolidated balance sheet data:

(In thousand s)

	2002	2001	2000
	C$	C$	C$
Cash and short term investments	$ 108	$ 43	$ 1
Accounts receivable and prepaids	7,971	6,880	2,505
Capital assets	94,354	73,139	18,335
Total assets	102,717	80,063	22,101
Total stockholders equity	38,663	33,524	7,371

Quarterly information:

(In thousand s, except per share data)

	Q1	Q2	Q3	Q4
	March 31	June 30	September 30	December 31
	C$	C$	C$	C$
Year 2002				
Revenue	$ 5,598	$ 5,051	$ 5,036	$ 10,060
Income from operations	$ 326	$ 620	$ 854	$ 1, 109
Per share, basic	$ 0.04	$ 0.07	$ 0.09	$ 0.12
Per share, diluted	$ 0.04	$ 0.07	$ 0.09	$ 0.11
Net earnings	$ 3,150	$ 398	$ 714	$ 715

Per share, basic	$ 0.34	$ 0.04	$ 0.08	$ 0.08
Per share, diluted	$ 0.34	$ 0.04	$ 0.08	$ 0.07
Year 2001				
Revenue	$ 4,288	$ 4,670	$ 6,326	$ 4,980
Income from operations	$ 946	$ 1,497	$ 991	($206)
Per share, basic	$ 0.17	$ 0.26	$ 0.13	($ 0.21)
Per share, diluted	$ 0.17	$ 0.26	$ 0.13	($ 0.21)
Net earnings	$ 610	$ 470	$ 648	($ 111)
Per share, basic	$ 0.11	$ 0.08	$ 0.09	($ 0.05)
Per share, diluted	$ 0.11	$ 0.08	$ 0.09	($ 0.05)

Cautionary Note Regarding Forward-Looking Statements

The following discussion of our results of operations and financial condition should be read in conjunction with the consolidated financial statements and other financial information included in this annual report. The statements that relate to matters that are not historical facts are "forward-looking statements" within the meaning of Section 27A of the Securities Exchange Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "project", "will", "should" "could", "may", "predict" and similar expressions are intended to identify forward-looking statements. Future events and actual results may differ materially from the results set forth in or implied in the forward-looking statements. Factors that might cause such a difference such as those discussed under "Risk factors" and elsewhere, include:

fluctuations in worldwide prices of oil and natural gas and demand for oil and natural gas;

fluctuations in levels of oil and gas exploration and development activities;

the existence of competitors, technological changes and developments in the industry;

the existence of operating risks and hazards inherent in the industry, such as blowouts, oil spills, fires, adverse weather, natural disasters, injury to third parties, oil spills and other environmental damages;

the existence of regulatory uncertainties;

possible insufficient liquidity to meet the Company s expansion plans; and

general economic conditions.

The following discussion is to inform you about our financial conditions, liquidity and capital resources as of December 31, 2002 and 2001 and the results of operations for the years ended December 31, 2002 and 2001. The information is expressed in Canadian dollars.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Financial Condition, Liquidity and Capital Resources

At December 31, 2002 Enterra s working capital was a deficit of $37.98 million (2001 - $2.2 million). Included as part of current liabilities at December 31, 2002 is bank debt of $24.3 million (2001 - NIL). The Company s bank debt now appears on our balance sheets as a current liability. This same bank debt was classified as a long-term liability at December 31, 2001. Nothing has changed with the nature or the terms of our banking arrangement with our lender. The reclassification of our bank debt from long-term liability to current liability is the result of new Canadian accounting rules which came into effect January 1, 2002. These rules specify that all borrowings where, among other things, the lender has a right to demand repayment within 12 months (which is the case with our revolving production facility) are to be classified as current liabilities. We are not subject to principal repayments under our banking arrangement. Other than in the event of a default or a breach of covenants, our lender has advised us that no principal payments are required in 2002.

Cash flow from operations was $11.95 million in 2002 (2001 - $9.81 million) . The increase was largely due to the added production as a result of the Clair project, which came on near the end of the year, and to a slightly better pricing environment in 2002. Average commodity prices during 2002 were $30.41 per boe compared to $29.14 per boe in 2001.

During the year ended December 31, 2002 there was an increase in non-cash working capital of $10.57 million compared to a decrease in non-cash working capital of $0.48 million in 2001. The 2002 increase was the direct result of the accelerated drilling activity in November and December of 2002, which resulted in higher accounts payables and accrued liabilities at the end of 2002.

Financing Activities

Enterra s ability to maintain and grow its operating income and cash flow is dependent upon continued capital spending to replace depleting assets. Enterra believes its future cash flow from operations, borrowing capacity and future equity issues should be sufficient to fund capital expenditures and to service debt. However, our ability to raise additional funds at all, or to do so on acceptable terms, depends largely on factors beyond our control, such as world prices for oil and gas, prevailing interest rates and general economic conditions.

Enterra s bank debt at December 31, 2002 was $24.3 million (2001 - $18.4 million). In both periods the funds were used to acquire capital assets and support ongoing operations. At December 31, 2002 Enterra s bank facility consisted of a line of credit of $26.7 million (of which $24.4 was drawn). Interest on amounts drawn is based on the bank s prime rate plus 0.25%.

Security is provided by a first charge over all of the Company s assets. While the loan is repayable on demand, Enterra is not subject to scheduled repayments. The lender has advised the Company that, subject to annual review of the borrowing base and the Company continuing to comply with the terms of the loan agreement, no payments will be required in 2002.

In the second quarter of 2002, the Company sold its Grand Forks property for $5.3 million. Proceeds from this sale were used to reduce our bank debt and to repurchase some of the preferred shares. The preferred shares were redeemed for $2.3 million, paid for with cash of $1.75 million and a note of $550,000. On August 15, 2002 the note was settled for $325,000, resulting in a gain of $206,181 net of related legal costs.

The Company has in excess of $60 million in tax pools available at December 31, 2002.

On October 1, 2002 the Company 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.

The Company completed a secondary public offering in the United States in January of 2001, consisting of 1,000,000 units of one common share and one share purchase warrant for US$4.55 per unit. The share purchase warrants have an expiry date of April 17, 2002 and are exercisable at US$3.50 per share. The proceeds from this offering were used to purchase the Grand Forks oil and gas assets for $5.5 million in March of 2001.

- 22 -

Effective August 1, 2001, Enterra acquired 100% of Big Horn for cash of $2.2 million (not including acquisition costs) and the issuance of 3,496,436 common shares and 7,418,336 preferred shares. Enterra has also repurchased, through its previously announced share buyback program, 232,500 of its common shares during 2001.

The Company s total debt, including working capital deficiency and preferred shares, at December 31, 2002 was $42.7 million (December 31, 2001 - $26.9 million).

Investing Activities

The timing of most of Enterra s capital expenditures is discretionary. Enterra has no material long-term commitments associated with its capital expenditure plans or operating agreements. Consequently, the Company has a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The level of capital expenditures will vary in future periods depending on the success we experience on planned drilling activities, oil and gas price conditions and other related economic factors.

Capital expenditures for the year ended December 31, 2002 were $35.88 million (2001 - $14.96 million). Drilling activity was minimal in the first ten months of 2002 but increased substantially in November and December. Almost $20 million was spent in the fourth quarter of 2002, representing over 50% of the entire 2002 capital expenditures.

The Company drilled 62 (57.7 net) wells in 2002, resulting in 25 (23.7 net) oil wells and 37 (34.0 net) gas wells. Only 8 wells were drilled in the first nine months of 2002. The remaining 54 wells (87% of total wells drilled in 2002) were all drilled in the fourth quarter of 2002.

Proceeds on disposal of oil and gas properties were $5.8 million in 2002 (2001 - $1.7 million). These proceeds 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.

Results of Operations

Gross revenue for the year ended December 31, 2002 was $25.7 million (2001 - $20.3 million) for a 27% increase. Production volumes for the year ended December 31, 2002 averaged 2,320 boe/day (2001 1,906 boe/day) for a 22%

increase. The increases in revenue and production volumes are consistent given that commodity prices, on average, were only 4% higher in 2002 than 2001 ($30.41 per boe in 2002 compared with $29.14 per boe in 2001).

The Company received an average of $33.86 per barrel for its oil production in 2002 compared with $30.53 in 2001. The Company received an average of $4.08 per mcf for its natural gas production during 2002 compared with $3.66 in 2001.

Royalties for year ended December 31, 2002 were $4.2 million (2001 - $3.2 million) for a 32% increase. As a percentage of oil and gas revenues, royalties were 16% for both 2002 and 2001.

Operating expenses for the year ended December 31, 2002 were $6.0 million (2001 - $5.8 million). Operating costs increased by only 3% in 2002 despite a 27% increase in revenue. This is the result of the Company s commitment to reducing operating expenses since the Westlinks/Big Horn merger in August 2001. On a barrel of oil equivalent basis operating costs for the year ended December 31, 2002 were $7.11 per boe (2001 - $8.38 per boe) for a 15% decrease. The reduction in operating costs on a per boe basis should continue over the next quarters as the Company focuses its drilling on a few selected areas, which makes it easier to manage and control costs.

General and administrative expenses for the year ended December 31, 2002 were $1.7 million (2001 - $0.6 million) for a 198% increase. On a barrel of oil equivalent basis administrative costs were $1.99 per boe in 2002 (2001 - $0.81 per boe). The 2001 general and administrative expenses only reflected the combined entities (Big Horn and Westlinks) for five months of the year, from August to December. There were additional costs in 2002 related to staffing levels and also increased marketing and travel costs as the Company focused its attention on its larger U.S. shareholder base. Overhead recoveries also decreased in 2002 as the Company maintained a much larger working interest than it did in 2001. The Company s two largest projects in 2002, Clair and Bindloss, were drilled with a 100% working interest. As the Company s production continue to increase in 2003 the general and administrative expenses should settle to a level between $1.00 and $2.00 per boe.

- 23 -

Interest expense for the year ended December 31, 2002 was $1.2 million (2001 - $0.6 million). The increase in interest expense is due to higher debt levels in 2002. Included in interest expense in 2002 is $22,549 of dividends paid to the preferred shareholders. There were no dividends paid to preferred shareholders in 2001.

Depletion and depreciation for the year ended December 31, 2002 was $9.3 million (2001 - $6.9 million). The increase reflects the higher cost base in our capital assets in 2002. As a percentage of revenue, the depletion and depreciation expense were 36% in 2002 and 34% in 2001.

The Company began amortizing its deferred financing charges in 2002. The provision was $390,800. The balance remaining on the balance sheet at December 31, 2002 was $284,040.

Enterra incurred $0.9 million of one-time restructuring charges (mainly severance and termination payments) in 2001 as a result of the Big Horn acquisition. There were no such costs in 2002.

Current and future income tax expense for the year ended December 31, 2002 were $132,000 and $911,000 respectively (2001 $120,000 and $562,000). The future income tax expense is calculated based on the timing of deductions for accounting purposes and tax on the Company s assets.

The Company s earnings for the year ended December 31, 2002 were $4.98 million (2001 - $$1.62 million). This large increase was caused mainly by a $3.1 million gain on redemption of preferred shares which occurred in the first quarter of 2002. Enterra redeemed 6,123,870 of its Series 1 preferred shares with a face redemption price of $5,205,290 for $2.1 million, resulting in a gain of $3.1 million. Without this gain, earnings would have been $1.86

million, an increase of 15%.

Earnings per share for the year ended December 31, 2002 were $0.54 (2001 - $0.23). The weighted average number of shares outstanding in 2002 was 9,154,491 (2001 6,992,393).

The Company had 9,176,325 common shares outstanding at December 31, 2002 (December 31, 2001 - 9,150,622)

Subsequent Event Sale of Non-Core Properties

Subsequent to December 31, 2002 the Company sold some non-core oil and gas properties for proceeds of $4.3 million.

Subsequent Event Hedging Contracts

Subsequent to December 31, the Company entered into several contracts to deliver 2,000 barrels of oil per day for the period April 1, 2003 and December 31, 2003. The prices and volumes are as follows:

Volumes (in barrels per day)	Price (in US dollars)
1,000	US$29.60
250	US$29.71
250	US$29.50
500	US$29.80

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. The Company 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 Company 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 the Company s consolidated financial condition and results of operations would be affected. For example, the Company 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, the Company 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) The Company 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 the Company s management to use differing assumptions, estimates and judgments, then the Company s consolidated financial condition and results of operations would be affected. For example, the Company would have lower net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in increased impairment expense.

Qualitative and Quantitative Disclosures about Market and Credit Risk

We are exposed to all of the normal market risks inherent within the oil and gas, 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, which is incorporated by reference here.

Sensitivities

(Cdn$)	Cash Flow	Net Income
Estimated 2003 impact:		
Crude Oil - US $1.00/bbl change in WTI	$936,000	$378,000
Natural Gas - US $0.50/mcf change	$817,000	$330,000
Foreign Exchange - $0.01 change in US to Cdn Dollar	$233,000	$69,000
Interest Rates - 1% change	$250,000	$145,000

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 customer and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance.

Market Risk

We are exposed to market risk from changes in currency exchange rates and interest rates. As a Canadian oil and gas company, we may be adversely affected by changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and gas production is expressed in U.S. dollars, which is the standard for the oil and gas industry world-wide. 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.

- 25 -

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2002, we had $24,436,640 of indebtedness bearing interest at floating rates and $4,921,598 of long-term debt bearing interest at fixed rates.

Enterra regularly assess its exposure and monitor opportunities to manage these risks, as follows:

(a) Effective January 31, 2001, the Company settled a fixed price contract eliminating the requirement to deliver set physical quantities of oil at fixed prices. Upon the cancellation of the contract the Company received approximately $1,680,000, which is being recognized into income over the term of the contract. At December 31, 2002 the remaining deferred gain related to this settlement was $237,463 (December 31, 2001 - $761,302).

(b) During 2002 and 2001, the Company entered into costless collars and forward contracts to establish a minimum price for the Company s future sales of crude oil and gas. The contracts are as follows:

(i) The Company entered into a zero cost collar arrangement during 2001 which provides a floor price of US$20 per barrel and a ceiling price of US$24 per barrel for 500 barrels of oil per day. The contract is effective from November 1, 2001 through April 30, 2002.

(ii) In July 2002, the Company entered into a zero cost collar arrangement with a floor price of US$22 per barrel and a ceiling price of US$28 per barrel for 500 barrels of oil per day. The contract is effective from October 1, 2002 through March 31, 2003. At December 31, 2002 this contract had an estimated negative market value of $216,000.

(iii) In July 2002, the Company entered into two contracts to deliver natural gas. One is for 1,500 mcf per day, priced at CDN$4.60 per mcf. The other is for 1,500 mcf per day, priced at CDN$4.45 per mcf. Both contracts are effective from November 1, 2002 through March 31, 2003. At December 31, 2002 these contracts had an estimated negative market value of $369,000.

Contractual Obligations and Commitments

The Company has assumed various contractual obligations and commercial commitments in the normal course of its operations and financing activities. Contractual obligations are financial in nature and are considered to represent known future cash payments that we are required to make under existing contractual arrangements, such as debt and lease arrangements.

The Company has commitments for the following payments over the next five years:

	2003	2004	2005	2006	Thereafter 2007
Capital lease obligations	$1,118,994	$1,118,994	$1,070,068	$1,065,620	$1,799,215
Note payable	86,284				
Rental payments re-office space	447,357	429,854	165,121	114,894	
	$1,652,635	$1,548,848	$1,235,189	$1,180,514	$1,799,215

New Accounting 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 fiscal years beginning on or after July 1, 2003. Adoption of AcG-13 is not expected to have a material impact on the Company s financial position or results of operations.

In September 2002, the CICA approved Section 3063, "Impairment of Long-Lived Assets" (S.3063). S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The Company is currently assessing the impact that adoption of this standard would have on its consolidated financial position and results of operation.

- 26 -

In December 2002, the CICA approved Section 3110, "Asset Retirement Obligations" (S.3110). S.3110 requires liability recognition for retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. S.3110 is effective for fiscal years beginning on or after January 1, 2004. The total impact on our financial statements has not yet been determined.

The following standards and revisions issued by the CICA do not impact us:

(i) Amendments to S.3025 - "Impaired Loans", effective for asset foreclosures on or after May 1, 2003.

(ii) Section 3475 - "Disposal of Long-Lived Assets and Discontinued Operations", effective for disposal activities initiated by commitments to plans on or after May 1, 2003.

In June 2001, the US Financial Accounting Standards Board (FASB) issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires liability recognition for retirement obligations associated with the Company s property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. The Company is currently assessing the impact that adoption of this standard would have on its consolidated financial position and results of operation.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures the Company must make about our obligations under certain guarantees that we have issued. It also requires us to recognize, at the inception of a guarantee, a liability for the fair value of the obligations the Company has undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied only to guarantees issued or modified after December 31, 2002. Adoption of these provisions will not have a material impact on the Company s financial position or results of operations. The disclosure requirements are effective for annual or interim periods ending after December 15, 2002.

In January 2003, the FASB issued Statement No. 148 "Accounting for Stock-Based Compensation - Transition and Disclosure, an Amendment of FASB Statement No. 123" (FAS 148). FAS 148 amends FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair-value based method of accounting for stock-based employee compensation. In addition, FAS 148 amends the disclosure requirements of FAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. FAS 148 has no material impact on the Company as the Company does not plan to adopt the fair-value method of accounting for stock options at the current time.

The following standards issued by the FASB do not impact the Company:

(i) Statement No. 145 "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" effective for financial statements issued on or after May 15, 2002;

(ii) Statement No. 146 "Accounting for Costs Associated with Exit or Disposal Activities" effective for exit or disposal activities initiated after December 31, 2002;

(iii) Statement No. 147 "Acquisitions of Certain Financial Institutions - an Amendment of FASB Statements No. 72 and 144 and FASB Interpretation No. 9" effective for acquisitions on or after October 1, 2002; and

(iv) Interpretation No. 46 "Consolidation of Variable Interest Entities" effective for financial statements issued after January 31, 2003.

<u>Factors That May Affect Future Results</u>

This report, including Management s Discussion and Analysis or Plan of Operation, contains forward-looking statements and other prospective information relating to future events. These forward-looking statements and other information are subject to certain risks and uncertainties that could cause results to differ materially from historical or anticipated results, including the following:

Risks related to our industry and business

We have a working capital deficiency at December 31, 2002; our Credit facilities can be called at any time.

At December 31, 2002, we had a working capital deficiency of $37,983,234, which means our current liabilities exceeded our current assets by that amount. Our bank debt is classified as a current liability as it is a facility based on a demand basis and could be called for repayment at any time.

Our assets are highly leveraged.

We have incurred 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 loan or may cause the bank that issued our loan to determine that our assets are insufficient security for our bank debt.

There is uncertainty about estimates used in this annual report and they may prove to be inaccurate, resulting in a reduction of our working capital.

This annual report contains estimates of future net cash flows from our oil and gas reserves, prepared by independent engineers, which are based upon the estimates of oil and gas reserves in the ground and the percentage of those reserves which can be recovered and produced with current technology. These estimates include assumptions as to the prices received for the sale of oil and gas. Any one or all of those estimates may be inaccurate, which could materially affect our estimate of future net cash flows. In addition, the cost of capital and operating expenses could be higher than estimated, resulting in a reduction in working capital and the need to raise additional capital.

Our operations are subject to numerous risks of crude oil and natural gas drilling and production activities.

Crude oil and natural gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the following:

- that no commercially productive crude oil or natural gas reservoirs will be found;
- that crude oil and natural gas drilling and production activities may be shortened, delayed or canceled; and
- that our ability to develop, produce and market our reserves may be limited by:
    - title problems,
    - weather conditions,
    - compliance with governmental requirements, and

mechanical difficulties or shortages or delays in the delivery of drilling rigs and other equipment.

In the past, we have had difficulty securing drilling equipment in certain of our core areas. We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for crude oil and natural gas may be unprofitable. Dry wells and wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. In addition, our properties may be susceptible to hydrocarbon draining from production by other operations on adjacent properties.

Our industry also experiences numerous operating risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, ruptures or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses also may result from injury or loss of life, severe damage to or destruction of property, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We operate in a highly competitive industry that may adversely affect our operations.

We operate in a highly competitive environment. Competition is particularly intense with respect to the acquisition of desirable undeveloped crude oil and natural gas properties. The principal competitive factors in the acquisition of such undeveloped crude oil and natural gas properties include the staff and data necessary to identify, investigate and purchase such properties, and the financial resources necessary to acquire and develop such properties. We compete with major and independent crude oil and natural gas companies for properties and the equipment and labor required to develop and operate such properties. Many of these competitors have financial and other resources substantially greater than ours.

The principal resources necessary for the exploration and production of crude oil and natural gas are leasehold prospects under which crude oil and natural gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of crude oil and natural gas operations. We must compete for such resources with both major crude oil and natural gas companies and independent operators. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations in the immediate future we cannot assure you that such materials and resources will be available to us.

Our ability to replace production with new reserves is highly dependent on acquisitions or successful development and exploration activities.

The rate of production from crude oil and natural gas properties declines as reserves are depleted. Our proved reserves will decline as reserves are produced unless we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. Our future crude oil and natural gas production is therefore highly dependent upon our level of success in acquiring or finding additional reserves. We cannot assure you that our exploration and development activities will result in increases in reserves. Our operations may be curtailed, delayed or cancelled if we lack necessary capital and by other factors, such as title problems, weather, compliance with governmental regulations, mechanical problems or shortages or delays in the delivery of equipment. Our ability to continue to acquire producing properties or companies that own such properties assumes that major integrated oil companies and independent oil companies will continue to divest many of their crude oil and natural gas properties. We cannot assure you that such divestitures will continue or that we will be able to acquire such properties at acceptable prices or develop additional reserves in the future.

Crude oil and natural gas price declines and volatility could adversely affect our revenue, cash flows and profitability.

Our revenue, profitability and future rate of growth depend substantially upon prevailing prices for crude oil and natural gas. Crude oil and natural gas prices fluctuate and until recently have declined significantly. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. In 1998 and 1999, we reduced our capital expenditures budget because of lower crude oil and natural gas prices. In addition, we may have ceiling test write-downs when prices decline. At December 31, 2001 the Company realized a U.S. GAAP ceiling test write-down of C$17.5 million (after tax). Lower prices may also reduce the amount of crude oil and natural gas that we can produce economically.

We may enter into hedge agreements and other financial arrangements at various times to attempt to minimize the effect of crude oil and natural gas price fluctuations. We cannot assure you that such transactions will reduce risk or minimize the effect of any decline in crude oil or natural gas prices. Any substantial or extended decline in crude oil or natural gas prices would have a material adverse effect on our business and financial results. Hedging activities may limit the risk of declines in prices, but such arrangements may also limit additional revenues from price increases.

Lower crude oil and natural gas prices increase the risk of ceiling limitation write-downs.

The Company changed its 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 the Company 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. 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.

- 29 -

The Company performs 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 the Company realized a U.S. GAAP ceiling test write-down of $17.5 million (after tax). There were no such write-down required at December 31, 2002.

The risk that the Company 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. The Company may experience additional ceiling test write-downs in the future.

Prior to 2001, the Company followed the "successful efforts" method of accounting for our oil and gas exploration and development costs. The initial acquisition costs of oil and gas properties and the costs of drilling and equipping development wells and successful exploratory wells were capitalized. The costs of exploration wells classified as unsuccessful were charged to expense. All other exploration expenditures, including geological and geophysical costs and annual rentals on exploratory acreage, were charged to expense as incurred. Under successful efforts accounting rules, the net capitalized cost of oil and gas properties could not exceed a "ceiling limit" which was based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of crude oil and natural gas properties exceeded the ceiling limit, the amount of the excess was charged to earnings. This is called a "ceiling limitation write-down." This charge did not impact cash flow from operating activities, but did reduce stockholders' equity. In 1997 and 2000, the Company recorded a write-down of $ 3.8 million and $0.5 million respectively, as a result of a downward adjustment to our proved reserves in Canada.

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.

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;
- amortization of substantial goodwill, adversely affecting our reported results of operations;
- 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.

We may be subject to environmental liability claims that could result in significant costs to us.

We may be subject to claims for damages related to any impact that our operations have on the environment. An environmental claim could materially adversely affect our business because of the costs of defending against these types of lawsuits, the impact on senior management's time and the potential damage to our reputation. Our oil and gas operations are subject to government regulations and control. Failure to comply with applicable government rules could restrict our ability to engage in further oil and gas exploration and development opportunities.

Our revenue is subject to volatile oil and gas prices that could reduce our revenue and profitability.

The price we receive for oil and gas production is subject to significant volatility. Our revenue, cash flow and profitability are substantially dependent on prevailing prices for oil and gas. Historically oil and gas prices and markets have been volatile and they are likely to continue to be volatile in the future. Some factors that contribute to volatility include:

political conditions in the Middle East, the former Soviet Union and other regions;

domestic and foreign supplies of oil and gas;

the level of consumer demand;

weather conditions;

domestic and foreign government regulations;

the availability and prices of alternative fuels; and

overall economic conditions.

To counter this volatility from time to time we may enter into agreements to receive fixed prices on its oil and gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, We will not benefit from such increases.

As a Canadian oil and gas company, we may be adversely affected by changes in the exchange rate between U.S. and Canadian dollars.

The price we receive for oil and gas production is expressed in U.S. dollars, which is the standard for the oil and gas industry worldwide. However, we pay 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.

We depend on key personnel for critical management decisions and industry contacts but have no employment contracts or key person insurance.

We are dependent upon the continued services of our management team. We do not have employment contracts with any of these executives and do not carry key person insurance on their lives. The loss of the services of our executive officers, through incapacity or otherwise, could have a material adverse effect on our business and would require us to seek and retain other qualified personnel.

We have not paid dividends, do not intend to pay dividends in the foreseeable future and are currently restricted from paying dividends pursuant to the terms of our credit facility and Alberta corporate law.

We have not paid any cash dividends on our common stock and do not expect to pay any cash or other dividends in the foreseeable future. The terms of our current banking credit facility prohibit us from declaring and paying dividends except from assets that are in excess of the required amount of security under our credit facility, and Alberta corporate law prohibits the payment of dividends unless stated solvency tests are met.

Our stock is thinly traded and is subject to price volatility.

Trading volume in our common stock has historically been limited. Accordingly, the trading price of our common stock could be subject to wide fluctuations in response to quarterly variations in operating results, changes in financial estimates by securities analysts, an imbalance of purchasers and sellers, or other factors.

Item 7.

Financial Statements

The Consolidated Financial Statements of Enterra are attached as follows:

Independent auditors reports to the shareholders F-1 and F-2

Enterra Energy Corp. s Consolidated Financial Statements as of and

for the years ended December 31, 2002 and 2001 F-3 through F-18

Item 8. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure

Previous Independent Auditors:

Enterra Energy Corp. ("Enterra") has used the services of KPMG

LLP since 2001. Effective October 23, 2002 Enterra engaged Deloitte & Touche LLP as its auditors.

KPMG reports on our financial statements for the fiscal years ended December 31, 2001 and December 31, 2002 contain no adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles.

Our Board of Directors approved the change in accountants.

For the two most recent fiscal years and the quarters ended March 31, 2002 and June 30, 2002, there has been no disagreement between us and KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to the satisfaction of KPMG would have caused it to make a reference to the subject matter of the disagreement in connection with its reports.

During the two most recent fiscal years and the quarters ended March 31, 2002 and June 30, 2002, we have not been advised of any matters described in Regulation S-B, Item 304(a)(I)(B).

New Independent Auditors:

We engaged Deloitte & Touche

LLP, Calgary, Canada as our new independent auditors as of October 23, 2002. Prior to such date, we did not consult with Deloitte & Touche LLP regarding (i) the application of accounting principles, (ii) the type of audit opinion that might be rendered by Deloitte & Touche, or (iii) any other matter that was the subject of a disagreement between us and our former auditor as described in Item 304(a)(1)(iv) of Regulation S-B.

PART III

Item 9.

Directors, Executive Officers, Promoters and Control Persons; **Compliance With Section 16(A) of the Exchange Act**

The directors and executive officers of Enterra as of December 31, 2002 were:

Name	Age	Position with Enterra
Walter Dawson	62	Director
Reg J. Greenslade	39	Chairman, Director, President and Chief Executive Officer
H.S. (Scobey) Hartley	70	Director
Doug Paul	54	Director
Norman G Wallace	64	Director
Thomas J. Jacobsen	68	Director, Chief Operating Officer
Albert Johnston	59	Vice President Operations
Luc Chartrand	46	Chief Financial Officer
Rick McHardy	34	Corporate Secretary
Tom Dirks	61	Vice-President Exploration
Trevor Spagrud	34	Vice-President Operations

Walter A. Dawson.

Mr. Dawson was formerly the Executive Chairman of Enserco Energy Services Corp. He resigned in March 2001 after the merger with Tetonka was completed to pursue the creation of Simmons Energy Services. In 1993, Mr. Dawson, through his 100%-owned holding company, Perfco Investments Ltd., purchased control of Bonus Petroleum Corp., a public company that became Enserco. Enserco is now a leader in the Canadian workover and drilling market with 200 service rigs and 30 drilling rigs in Canada and Australia and will achieve revenue of $250 million along with over $80 million cash flow in 2001. Prior to Perfco Investments, Mr. Dawson founded and served 19 years as President, Chief

Executive Officer, and director of Computalog Ltd. In 1972, Mr. Dawson purchased a cased-hole wireline unit from Gearhart Industries and incorporated Perfco Services Ltd., which later formed Computalog Gearhart Ltd. in 1978. He was instrumental in taking the company public on the Toronto Stock Exchange in 1980, negotiating an exclusive technology/supply agreement with Gearhart Industries for Canada. Afterwards, he entered the directional and fishing tool business, along with the incorporation of the company s first research center where he hired 50 research and development experts to design and build state-of-the-art well logging equipment. Mr. Dawson led and completed several financings to achieve this goal. Mr. Dawson is currently a director of Integrated Production Services, a Toronto Stock Exchange listed company, and is a director of Action Energy Inc., a private company. He also held positions on several oil and gas boards over his career for both service and producing companies. Mr. Dawson became a Director of Enterra in August 2001.

Reg J. Greenslade.

Mr. Greenslade became President of Big Horn in April 1995 and President and CEO and a Director of Enterra in August 2001 and Chairman of the Board in December 2002. Prior to joining Big Horn, Mr. Greenslade held senior positions with several medium- and large-sized oil and gas companies. Most recently Mr. Greenslade was with CS Resources Limited in the areas of exploitation engineering and project management from 1993 to 1995. He was previously with Saskatchewan Oil and Gas Corporation in the capacities of project management, production, and reservoir engineering. He has extensive experience with secondary recovery schemes and is recognized for his work in the specialized field of horizontal well technology.

H.S. (Scobey) Hartley.

Mr. Hartley was appointed a director of Enterra in May, 2000. He has been Chairman of Prism Petroleum Ltd. since January, 1997 and was formerly the President of Prism Petroleum Ltd. and a predecessor company from December, 1990 through December, 1996. Mr. Hartley has also served as the President of Faster Oilfield Services since June, 1995, and was the President of Cayenne Energy Corp. from 1990 through 1996. He received a Bachelor of Science degree in Geology from Texas Tech University in 1956.

Thomas J. Jacobsen.

Mr. Jacobsen joined Enterra as a director in February 1999, and was appointed Executive Vice-President, Operations in October 1999. In October 2000 he resigned from this position and was appointed the Vice-Chairman of the Board of Directors. He was also appointed President of a U.S. subsidiary to be created, Westlinks Inc. As President of Westlinks Inc., Mr. Jacobsen will review oil and gas opportunities in the United States. Through his company, Wells Gray Resort & Resources Ltd., Enterra also granted him a consulting contract through April 15, 2001; pursuant to which Mr. Jacobsen was be in charge of Enterra s drilling, completion and equipping projects. His more than 40 years of experience in the oil and gas industry in Alberta and Saskatchewan includes serving as the President and Chief Operating Officer of Americom Resources Corporation since June 2001; President and Chief Executive Officer of Niaski Environmental Inc. from November, 1996 to February, 1999; President and Chief Executive Officer of International Pedco Energy Corporation from September, 1993 to February, 1996, and President of International Colin Energy Corporation from October, 1987 to June, 1993. Mr. Jacobsen currently serves as a director of Niaski Environmental Inc., a company listed on the Canadian Venture Exchange. Niaski has made a proposal to its creditors under the *Bankruptcy and Insolvency Act* (Canada). The proposal has been approved by the creditors but has not yet been funded and completed. Mr., Jacobsen became Enterra s Chief Operating Officer in January 2002.

Luc Chartrand.

Mr. Chartrand worked for KPMG as a Chartered Accountant from 1985 to 1988 when he became a tax manager in their Calgary office. He left shortly thereafter and worked as a consultant to several Calgary companies. He moved to Toronto in 1990 to assist in the relocation and takeover of Financial Trust by Central Capital. He remained in Toronto until 1992 when he returned to Calgary with Morgan Financial Corporation. Shortly thereafter, he joined Bonus Resource Services Corp. as its Chief Financial Officer. Mr. Chartrand joined Big Horn Resources Ltd. in the fall of 1994 and became Chief Financial Officer in 1996. He became Chief Financial Officer of Enterra in August 2001.

Rick McHardy.

Mr. McHardy has been a partner with the law firm of McCarthy Tetrault LLP since July, 2002. Prior to joining McCarthy Tetrault, from August, 1999, Mr. McHardy practised law with the firm of Donahue LLP, an associated firm of Ernst & Young LLP. From July, 1995 to August, 1999, Mr. McHardy practised law with the firm of Code Hunter. Mr. McHardy specializes in mergers and acquisitions matters involving both public and private companies and has experience in a wide variety of corporate finance and securities transactions. Mr. McHardy obtained a Bachelor of Commerce degree from the University of Saskatchewan in 1990 and a Bachelor of Laws degree from the University of Saskatchewan in

1993.

Trevor Spagrud.

Mr. Spagrud started his professional career with Saskatchewan Oil and Gas (SaskOil) in 1990, gaining progressive experience in production, completions, and reservoir engineering. He remained at SaskOil, which became Wascana Energy, until 1996 when he held the position of Senior Development Engineer. In this position, Mr. Spagrud was responsible for all engineering functions in both development and exploration prospects. In 1996, he became the Engineering Manager at Truax Resources and remained there until the company was taken over in June 1997, at which time he moved to Big Horn. He became Big Horn s Vice President of Operations in 1998 and Enterra s Vice President of Operations in August 2001.

- 33 -

Doug Paul.

Mr. Paul had a career spanning over 30 years with the Royal Bank of Canada, during which time he held a number of administrative and lending positions. His assignments with the bank included the position of Senior Auditor, which entailed assessment of the quality of the bank s loan portfolio both domestically and internationally. Most recently Mr. Paul worked in the bank s oil and gas division where he administered a loan portfolio of some $500MM, which included domestic and international exploration and development companies, drilling and service companies. In that capacity, Mr. Paul supported the growth and development of the largest drilling and services companies in Western Canada. Currently as Vice President of Canada West Corporate Finance, where he has been engaged for some two years, Mr. Paul holds associate membership in C.A.O.D.C. and P.S.A.C.

Norman W.G. Wallace.

Mr. Wallace was elected a director of Enterra in May 2000. He has been the owner of Wallace Construction Specialties Ltd. since 1972. Mr. Wallace received a Bachelor of Commerce degree from the University of Saskatchewan in 1968. Mr. Wallace resigned as Director in August 2001 and was re-appointed in June 2002.

Albert Johnston.

Mr. Johnston has been President of AJ Consulting since 1982 and has worked with various drilling contractors in the design and supervision of drilling programs. Mr. Johnston was Operation Manager with Custom Drilling from 1980 to 1982. Mr. Johnston became Enterra s Vice President of Operations in June 2002.

Tom Dirks.

Mr. Dirks has been working as a Geologist in the U.S. and Canada since 1968. From 1968 to 1976 he worked with various companies on both sides of the border. He co-founded Exalta Petroleums Ltd. in 1976. Exalta became a wholly-owned subsidiary of Brinco Limited in 1979. Mr. Dirks was Executive Vice President of Brinco until 1982. Between 1982 and 1992, Mr. Dirks was President of Equine Resources Ltd., Laredo Petroleums Ltd. and Pedco Energy, all Vancouver publicly listed companies. Since 1992 Mr. Dirks has been working as a Geological Consultant for various exploration companies. He became Enterra s Vice President of Exploration in June 2002.

Board of Directors

Enterra is authorized to have a board of at least three directors and no more than ten. We currently have six directors. Our directors are elected for a term of about one year, from annual meeting to annual meeting, or until an earlier resignation, death or removal. Each officer serves at the discretion of the board or until an earlier resignation or death. There are no family relationships among any of our directors or officers. Alberta corporate law requires that we have at least two independent outside directors who are not officers or employees of Enterra.

Currently directors receive an annual retainer of $7,500. In addition, directors receive fees in the amount of $750 for each directors' meeting which they personally attend and $250 for each conference call which they participate in which exceeds 1 hour in duration. Directors are also entitled to be compensated for their out-of-pocket costs, including travel and accommodation, relating to their attendance at any directors' meeting. Finally, the directors are entitled to participate in the Corporation's stock option plan. During the year ended December 31, 2001, options to acquire a total of 240,000 common shares were granted to the current directors of the Corporation (not including options granted to a director who is also a named executive officer). Except as described herein, no compensation by way of annual retainer or meeting fees was paid to directors for acting in such capacity in the year ended December 31, 2002.

Committees of the Board of Directors

Enterra s Board of Directors currently has an audit committee, a compensation committee, a corporate governance committee and a reserves committee.

Audit Committee.

Our audit committee consists of Mr. Dawson (Chairman), Mr. Paul and Mr. Wallace, all three being independent directors. The audit committee reviews in detail and recommends approval of the full board of our annual and quarterly financial statements; recommends approval of the remuneration of our auditors to the full board; reviews the scope of the audit procedures and the final audit report with the auditors, and reviews our overall accounting practices and procedures and internal controls with the auditors.

- 34 -

Compensation Committee.

Our compensation committee consists of Mr. Hartley (Chairman), Mr. Wallace and Mr. Dawson. The compensation committee recommends approval to the full board of the compensation of the Chief Executive Officer, the annual compensation budget for all other employees, bonuses, grants of stock options and any changes to our benefit plans.

Corporate Governance Committee.

Our corporate governance committee consists of Mr. Wallace (Chairman), Mr. Dawson and Mr. Hartley. The corporate governance committee determines the scope and frequency of periodic reports to the board concerning issues relating to overall financial reporting, disclosure and other communications with all stakeholders.

Reserves Committee

. Our reserves committee consists of Mr. Paul (Chairman) and Mr. Hartley. The reserves committee reviews and recommends approval to the full board of Enterra s annual reserve report as prepared by independent reservoir engineers.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires the Company's directors and executive officers, and persons who own more than 10 percent of a registered class of the Company's equity securities, to file with the Securities and Exchange Commission (the "SEC") initial reports of ownership and reports of changes in ownership of Common Stock and other equity securities of the Company. Officers, directors and greater than ten percent stockholders are required by SEC regulation to furnish the Company with copies of all Section 16(a) forms they file.

As a foreign private issuer, Enterra is exempt from the rules under the exchange act prescribing the furnishing and content of proxy statements and our officers, directors and principal shareholders are exempt from the reporting and short-swing profit recovery provisions contained in section 16 of the exchange act.

Item 10. Executive Compensation

Executive Compensation

The following table provides a summary of compensation earned during the last fiscal year ended December 31, 2001 by the Corporation's executive officers during 2002. These officers were appointed to their positions in August 2001. The compensation shown below is based on a calendar 2002 year.

All monetary amounts are in Canadian dollars.

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)	Securities Under Options/ SARs Granted (#)	Restricted Shares or Restricted Share Units ($)	LTIP Payouts ($)	All Other Compensation ($)
Reginald J. Greenslade	2002	157,500	-	11,025	144,000	-	-	-
President and Chief Executive Officer								
Tom Jacobsen	2002	140,000	-	-	60,000	-	-	-
Chief Operating Officer								
Trevor R. Spagrud	2002	196,875	-	9,187	100,000	-	-	-
Vice-President, Engineering								
Luc Chartrand	2002	158,355	-	-	72,500	-	-	-
Chief Financial Officer								

Management Contracts

Enterra has employment contracts with Reginald Greenslade and Trevor Spagrud which provide that the named executive officer will be paid a severance payment if: (a) the named executive officer's employment is terminated; or (b) a change of control occurs in the Corporation and the named executive officer does not continue to be employed by the Corporation at a level of responsibility or a level of base salary and compensation at least commensurate with the named executive officer's level of responsibility, base salary and compensation immediately prior to the change of control and the named executive officer elects to terminate his employment within twelve (12) months of the change of control. The severance payment is based upon the named executive officer's monthly salary. Mr. Greenslade and Mr. Spagrud are entitled up to a maximum of 30 months and 24 months severance payment, respectively. Additionally, both Mr. Greenslade and Mr. Spagrud are entitled to additional allocation of benefits for past bonus amounts paid to each of them.

Stock Options

Enterra grants stock options from time to time to its directors, officers, key employees, and consultants. The terms and conditions of the options, in accordance with resolutions of our board of directors and the policies of the Canadian Venture Exchange, will not exceed a term of five years. The option price may be at a discount to market price, which discount will not, in any event, exceed that permitted by any stock exchange on which our shares are listed for trading.

Ten percent of Enterra s shares of issued and outstanding common stock from time to time are reserved for issuance pursuant to stock options. The aggregate number of shares reserved for issuance under option grants, together with any other employee stock option plans, options for services and employee stock purchase plans, will not exceed ten percent of the issued and outstanding shares of common stock. In addition, the aggregate number of shares so reserved for issuance to any one person shall not exceed five percent of the issued and outstanding shares of common stock.

If an optionee ceases to be eligible due to the loss of corporate office or employment for any reason other than death, the option terminates not later than 30 days after the loss of such corporate office; provided that in the event of termination of employment for cause, the board of directors may resolve that the option shall terminate on the date of such termination. Option agreements also provide that estates of deceased participants can exercise their options for a period not exceeding one year following death.

Stock Options Granted During the Most Recently Completed Financial Year

The following table discloses the grants of options to purchase or acquire shares of common stock to our executive officers during the fiscal year ended December 31, 2002. All monetary amounts are in Canadian dollars.

Option Grants During Fiscal Year Ended December 31, 2002

Name	**Number of Securities Under Options Granted (#)**	**% of Total Options Granted to Employees in FY Ended Dec. 31, 2002**	**Exercise Price ($/share)**	**Unexercised options at December 31, 2002 (#)**	**Expiration Date**
Albert Johnston	20,000	8.6%	$ 4.41	20,000	June 6, 2007
Albert Johnston	5,000	2.2%	$ 6.00	5,000	July 2, 2007
Tom Dirks	25,000	10.8%	$6.00	25,000	July 2, 2007

A total of 232,000 options were granted by Enterra during the fiscal year ended December 31, 2002.

Aggregated Option Exercises During the Most Recently Completed Financial Year and Financial Year End Option Values

The following table sets forth the aggregate of options exercised by our executive officers during the year ended December 31, 2002 and the December 31, 2001 year-end values for options granted to the executive officers. All monetary amounts are in Canadian dollars. Add space below in far right column to improve readability

Name	**Securities Exercised (#)**	**Aggregate Value Realized ($)**	**Unexercised Options at FY-End Exercisable/ Unexercisable (#)**	**Value of Unexercised in-the-Money Options at FY-End Exercisable/ Unexercisable ($) (1)**
Reg J. Greenslade	Nil	Nil	144,000	$695,016/ $360,504
Trevor Spagrud	Nil	Nil	100,000	$414,226/ $318,774
Luc Chartrand	Nil	Nil	72,500	

				$267,948/ $263,477
Tom Jacobsen	Nil	Nil	60,000	$109,950/ $329,850
Albert Johnston	Nil	Nil	25,000	Nil/ $183,250
Tom Dirks	Nil	Nil	25,000	Nil/ $183,250
Rick McHardy	Nil	Nil	15,000	$79,868/ $30,082

(1) The closing price of our shares of common stock on the TSX Venture Exchange on the last trading day in December, 2002 was $11.33.

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Item 11. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information regarding beneficial ownership of our common stock as of December 31, 2002, by:

each person who is known by Enterra to beneficially own more than 5% of our outstanding common stock;

each of our executive officers and directors; and

all executive officers and directors as a group.

Shares of common stock not outstanding but deemed beneficially owned because an individual has the right to acquire the shares of common stock within 60 days are treated as outstanding when determining the amount and percentage of common stock owned by that individual and by all directors and executive officers as a group.

	Number of Shares Beneficially owned	Percentage of shares outstanding
Reg J. Greenslade	322,703	3.21
Trevor Spagrud	124,681	1.24
Luc Chartrand	191,467	1.91
H.S. (Scobey) Hartley	65,000	0.65
Walter Dawson	464,896	4.63

Rick McHardy	16,524	0.16
Thomas J. Jacobsen	314,584	3.13
Albert Johnston	53,200	0.53
Tom Dirks	25,000	0.25
Executive officers and directors as a group	1,638,055	16.30
John P. McGrain (beneficial ownership > 5%)	549,200	5.47
Total	2,187,255	21.77

Notes:

(1) The address of each officer and director is Suite 2600, 500 - 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6. The address of Mr. McGrain is 233 South Orange Grove, Pasadena, California 91105.

- 37 -

(2) In the foregoing table, the common stock beneficially owned by:

Mr. Greenslade includes stock options to purchase 144,000 common shares at an exercise price of $4.00.

Mr. Spagrud includes stock options to purchase 100,000 common shares at an exercise price of $4.00.

Mr. Jacobsen includes stock options to purchase 60,000 common shares at an exercise price of $4.00 and 246,980 shares held by Wells Gray Resort & Resources Ltd.

Mr. Dawson includes stock options to purchase 60,000 common shares at an exercise price of $4.00 and 362,763 shares held by Perfco Investments Ltd.

Mr. Chartrand includes stock options to purchase 72,500 common shares at an exercise price of $4.00 and 32,861 shares held by Chevalier Financial Corporation.

Mr. McHardy includes stock options to purchase 15,000 common shares at an exercise price of $4.00.

Mr. Hartley consists of stock options to purchase 60,000 common shares at an exercise price of $4.00.

Mr. McGrain includes stock options to purchase 60,000 common shares at an exercise price of $4.00.

Mr. Johnston includes options to purchase 20,000 common shares at an exercise price of $4.41 and options to purchase 5,000 common shares at an exercise price of $6.00.

Mr. Dirks includes options to purchase 25,000 common shares at an exercise price of $6.00

Equity Compensation Plan Information

The following table indicates the number of equity securities of Enterra authorized for issuance as of December 31, 2002 with respect to compensation plans, including:

All compensation plans previously approved by security holders; and

All compensation plans not previously approved by security holders.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,071,703	$4.70	200,000
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	1,071,703	$4.70	200,000

Exchange Controls

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to non-resident holders of our subordinate voting shares, other than withholding tax requirements.

There is no limitation imposed by Canadian law or by our articles of incorporation or our other charter documents on the right of a non-resident to hold or vote subordinate voting shares, other than as provided by the "Investment Canada Act", the "North American Free Trade Agreement Implementation Act (Canada)" and the "World Trade Organization Agreement Implementation Act."

The Investment Canada Act requires notification and, in certain cases, advance review and approval by the Government of Canada of the acquisition by a "non-Canadian" of "control" of a "Canadian business", all as defined in the Investment Canada Act. Generally, the threshold for review will be higher in monetary terms for a member of the World Trade Organization or North American Free Trade Agreement.

Taxation

United States Taxation

The information set forth below is a summary of the material U.S. federal income tax consequences of the ownership and disposition of common stock by a U.S. Holder, as defined below. These discussions are not a complete analysis or listing of all of the possible tax consequences of such transactions and do not address all tax considerations that may be relevant to particular holders in light of their personal circumstances or to persons that are subject to special tax rules. In particular, the information set forth deals only with U.S. Holders that will hold common stock as capital assets within the meaning of the Internal Revenue Code of 1986, as amended, and who do not at any time own individually, nor are treated as owning 10% or more of the total combined voting power of all classes of our stock entitled to vote. In addition, this description of U.S. tax consequences does not address the tax treatment of special classes of U.S. Holders, such as banks, tax-exempt entities, insurance companies, persons holding subordinate voting shares as part of a hedging or conversion transaction or as part of a "straddle," U.S. expatriates, persons subject to the alternative minimum tax, dealers or traders in securities or currencies and holders whose "functional currency" is not the U.S. dollar. This summary does not address estate and gift tax consequences or tax consequences under any foreign, state or local laws other than as provided in the section entitled "Canadian Federal Income Tax Considerations" provided below.

As used in this section, the term "U.S. Holder" means:

an individual citizen or resident of the United States;

a corporation created or organized under the laws of the United States or any state thereof including the District of Columbia;

an estate the income of which is subject to United States federal income taxation regardless of its source;

a trust if a court within the United States is able to exercise primary jurisdiction over its administration and one or more U.S. persons have authority to control all substantial decisions of the trust; or

a partnership to the extent the interests therein are owned by any of the persons described in clauses (a), (b), (c) or (d) above.

Holders of common stock who are not U.S. Holders, sometimes referred to as "Non-U.S. Holders", should also consult their own tax advisors, particularly as to the applicability of any tax treaty.

The following discussion is based upon:

the Internal Revenue Code;

U.S. judicial decisions;

administrative pronouncements;

existing and proposed Treasury regulations; and

the Canada/ U.S. Income Tax Treaty.

Any of the above is subject to change, possibly with retroactive effect. We have not requested, and will not request, a ruling from the U.S. Internal Revenue Service with respect to any of the U.S. federal income tax consequences described below, and as a result, there can be no assurance that the U.S. Internal Revenue Service will not disagree with or challenge any of the conclusions we have reached and describe here.

HOLDERS OF COMMON STOCK ARE URGED TO CONSULT THEIR TAX ADVISORS AS TO THE PARTICULAR CONSEQUENCES TO THEM UNDER U.S. FEDERAL, STATE, LOCAL AND APPLICABLE FOREIGN TAX LAWS OF THE ACQUISITION, OWNERSHIP AND DISPOSITION OF COMMON STOCK.

Dividends

Subject to the discussion of passive foreign investment companies below, the gross amount of any distribution paid by us to a U.S. Holder will generally be subject to U.S. federal income tax as foreign source dividend income to the extent paid out of our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. The

amount of any distribution of property other than cash will be the fair market value of such property on the date of the distribution. Dividends received by a U.S. Holder will not be eligible for the dividends received deduction allowed to corporations. To the extent that an amount received by a U.S. Holder exceeds such holder's allocable share of our current and accumulated earnings and profits, such excess will be applied first to reduce such U.S. Holder's tax basis in his subordinate voting shares, thereby increasing the amount of gain or decreasing the amount of loss recognized on a subsequent disposition of the subordinate voting shares. Then, to the extent such distribution exceeds such U.S. Holder's tax basis, it will be treated as capital gain. We do not currently maintain calculations of our earnings and profits for U.S. federal income tax purposes.

The gross amount of distributions paid in Canadian dollars, or any successor or other foreign currency, will be included in the income of such U.S. Holder in a dollar amount calculated by reference to the spot exchange rate in effect on the day the distributions are paid regardless of whether the payment is in fact converted into U.S. dollars. If the Canadian dollars, or any successor or other foreign currency, are converted into U.S. dollars on the date of the payment, the U.S. Holder should not be required to recognize any foreign currency gain or loss with respect to the receipt of Canadian dollars as distributions. If, instead, the Canadian dollars are converted at a later date, any currency gains or losses resulting from the conversion of the Canadian dollars will be treated as U.S. source ordinary income or loss. Any amounts recognized as dividends will generally constitute foreign source "passive income" or, in the case of certain U.S. Holders, "financial services income" for U.S. foreign tax credit purposes. A U.S. Holder will have a basis in any Canadian dollars distributed equal to their dollar value on the payment date.

A Non-U.S. Holder of common stock generally will not be subject to U.S. federal income or withholding tax on dividends received on common stock unless such income is effectively connected with the conduct by such Non-U.S. Holder of a trade or business in the United States.

Sale or Exchange

A U.S. Holder's initial tax basis in the common stock will generally be cost to the holder. A U.S. Holder's adjusted tax basis in the common stock will generally be the same as cost, but may differ for various reasons including the receipt by such holder of a distribution that was not made up wholly of earnings and profits as described above under the heading "Dividends." Subject to the discussion of passive foreign investment companies below, gain or loss realized by a U.S. Holder on the sale or other disposition of common stock will be subject to U.S. federal income taxation as capital gain or loss in an amount equal to the difference between the U.S. Holder's adjusted tax basis in the common stock and the amount realized on the disposition. In the case of a non-corporate U.S. Holder, the federal tax rate applicable to capital gains will depend upon:

the holder's holding period for the common stock, with a preferential rate available for common stock held for more than one year; and

the holder's marginal tax rate for ordinary income.

Any gain realized will generally be treated as U.S. source gain and loss realized by a U.S. Holder generally also will be treated as from sources within the United States.

The ability of a U.S. Holder to utilize foreign taxes as a credit to offset U.S. taxes is subject to complex limitations and conditions. The consequences of the separate limitation calculation will depend upon the nature and sources of each U.S. Holder's income and the deductions allocable thereto. Alternatively, a U.S. Holder may elect to claim all foreign taxes paid as an itemized deduction in lieu of claiming a foreign tax credit. A deduction does not reduce U.S. tax on a dollar-for-dollar basis like a tax credit, but the availability of the deduction is not subject to the same conditions and limitations applicable to foreign tax credits.

If a U.S. Holder receives any foreign currency on the sale of common stock, such U.S. Holder may recognize ordinary income or loss as a result of currency fluctuations between the date of the sale of common stock and the date the sale proceeds are converted into U.S. dollars.

A Non-U.S. Holder of common stock generally will not be subject to U.S. federal income or withholding tax on any gain realized on the sale or exchange of such common stock unless:

such gain is effectively connected with the conduct by such Non-U.S. Holder of a trade or business in the United States; or

in the case of any gain realized by an individual Non-U.S. Holder, such Non-U.S. Holder is present in the United States for 183 days or more in the taxable year of such sale and certain other conditions are met.

Personal Holding Company

We could be classified as a personal holding company for U.S. federal income tax purposes if both of the following tests are satisfied:

if at any time during the last half of our taxable year, five or fewer individuals own or are deemed to own more than 50% of the total value of our shares; and we receive 60% or more of our U.S. related gross income from specified passive sources, such as royalty payments.

A personal holding company is taxed on a portion of its undistributed U.S. source income, including specific types of foreign source income which are connected with the conduct of a U.S. trade or business, to the extent this income is not distributed to shareholders. We do not believe we are a personal holding company presently and we do not expect to become one. However, we cannot assure you that we will not qualify as a personal holding company in the future.

Foreign Personal Holding Company

We could be classified as a foreign personal holding company if in any taxable year both of the following tests are satisfied:

five or fewer individuals who are United States citizens or residents own or are deemed to own more than 50% of the total voting power of all classes of our shares entitled to vote or the total value of our shares; and

at least 60%, 50% in some cases, of our gross income, as adjusted, consists of "foreign personal holding company income", which generally includes passive income such as dividends, interests, gains from the sale or exchange of shares or securities, rent and royalties.

If we are classified as a foreign personal holding company and if you hold shares in us, you may have to include in your gross income as a dividend your pro rata portion of our undistributed foreign personal holding company income. If you dispose of your shares prior to such date, you will not be subject to tax under these rules. We do not believe we are a foreign personal holding company presently and we do not expect to become one. However, we cannot assure you that we will not qualify as a foreign personal holding company in the future.

Passive Foreign Investment Company

We believe that our common stock should not currently be treated as stock of a passive foreign investment company for United States federal income tax purposes, but this conclusion is a factual determination made annually and thus may be subject to change based on future operations and composition and valuation of our assets. In general, we will be a passive foreign investment company with respect to a U.S. Holder if, for any taxable year in which the U.S. Holder holds our subordinate voting shares, either:

at least 75% of our gross income for the taxable year is passive income; or

at least 50% of the average value of our assets is attributable to assets that produce or are held for the production of passive income.

For this purpose, passive income includes income such as:

dividends;

interest;

rents or royalties, other than certain rents or royalties derived from the active conduct of trade or business;

annuities; or

gains from assets that produce passive income.

If a foreign corporation owns at least 25% by value of the stock of another corporation, the foreign corporation is treated for purposes of the passive foreign investment company tests as owning its proportionate share of the assets of the other corporation and as receiving directly its proportionate share of the other corporation's income.

- 41 -

If we are treated as a passive foreign investment company, a U.S. Holder that did not make a qualified electing fund election or, if available, a mark-to-market election, as described below, would be subject to special rules with respect to:

any gain realized on the sale or other disposition of common stock; and

any "excess distribution" by us to the U.S. Holder.

Generally, "excess distributions" are any distributions to the U.S. Holder in respect of the subordinate voting shares during a single taxable year that are greater than 125% of the average annual distributions received by the U.S. Holder in respect of the common stock during the three preceding taxable years or, if shorter, the U.S. Holder's holding period for the common stock.

Under the passive foreign investment company rules,

the gain or excess distribution would be allocated ratably over the U.S. Holder's holding period for the common stock;

the amount allocated to the taxable year in which the gain or excess distribution was realized would be taxable as ordinary income;

the amount allocated to each prior year, with certain exceptions, would be subject to tax at the highest tax rate in effect for that year; and

the interest charge generally applicable to underpayments of tax would be imposed in respect of the tax attributable to each such year.

A U.S. Holder owning actually or constructively "marketable stock" of a passive foreign investment company may be able to avoid the imposition of the passive foreign investment company tax rules described above by making a mark-to-market election. Generally, pursuant to this election, such holder would include in ordinary income, for each taxable year during which such stock is held, an amount equal to the increase in value of the stock, which increase will

be determined by reference to the value of such stock at the end of the current taxable year compared with their value as of the end of the prior taxable year. Holders desiring to make the mark-to-market election should consult their tax advisors with respect to the application and effect of making such election.

In the case of a U.S. Holder who does not make a mark-to-market election, the special passive foreign investment company tax rules described above will not apply to such U.S. Holder if the U.S. Holder makes an election to have us treated as a qualified electing fund and we provide certain required information to holders. For a U.S. Holder to make a qualified electing fund election, we would have to satisfy certain reporting requirements. We have not determined whether we will undertake the necessary measures to be able to satisfy such requirements in the event that we were treated as a passive foreign investment company.

A U.S. Holder that makes a qualified electing fund election will be currently taxable on its pro rata share of our ordinary earnings and net capital gain, at ordinary income and capital gains rates, respectively, for each of our taxable years, regardless of whether or not distributions were received. The U.S. Holder's basis in the common stock will be increased to reflect taxed but undistributed income. Distributions of income that had previously been taxed will result in a corresponding reduction of basis in the common stock and will not be taxed again as a distribution to the U.S. Holder. U.S. Holders desiring to make a qualified electing fund election should consult their tax advisors with respect to the advisability of making such election.

United States Backup Withholding and Information Reporting

A U.S. Holder will generally be subject to information reporting with respect to dividends paid on, or proceeds of the sale or other disposition of, our subordinate voting shares, unless the U.S. Holder is a corporation or comes within certain other categories of exempt recipients. A U.S. Holder that is not an exempt recipient will generally be subject to backup withholding at a rate of 31% with respect to the proceeds from the sale or the disposition of, or with respect to dividends on, common stock unless the U.S. Holder provides a taxpayer identification number and otherwise complies with applicable requirements of the backup withholding rules. Any amount withheld under these rules will be creditable against the U.S. Holder's U.S. federal income tax liability or refundable to the extent that it exceeds such liability. A U.S Holder who does not provide a correct taxpayer identification number may be subject to penalties imposed by the United States Internal Revenue Service.

Non-U.S. Holders will generally be subject to information reporting and possible backup withholding with respect to the proceeds of the sale or other disposition of common stock effected within the United States, unless the holder certifies to its foreign status or otherwise establishes an exemption if the broker does not have actual knowledge that the holder is a U.S. holder. A payor within the United States will be required to withhold 31% of any payments of dividends on or proceeds from the sale of common stock within the United States to a non-exempt U.S. or Non-U.S. Holder if such holder fails to provide appropriate certification. In the case of such payments by a payor within the United States to a foreign partnership other than a foreign partnership that qualifies as a "withholding foreign partnership" within the meaning of such Treasury regulations, the partners of such partnership will be required to provide the certification discussed above in order to establish an exemption from backup withholding tax and information reporting requirements.

- 42 -

Canadian Federal Income Tax Considerations

The following is a summary of the material Canadian federal income tax considerations generally applicable to a U.S. person who holds common stock and who, for the purposes of the Income Tax Act (Canada), or the "ITA", and the Canada-United States Income Tax Convention (1980), or the "Convention," as applicable and at all relevant times:

is resident in the United States and not resident in Canada;

holds the common stock as capital property;

does not have a "permanent establishment" or "fixed base" in Canada, as defined in the Convention; and deals at arm's length with us. Special rules, which are not discussed below, may apply to "financial institutions", as defined in the ITA, and to non-resident insurers carrying on an insurance business in Canada and elsewhere.

This discussion is based on the current provisions of the ITA and the Convention and on the regulations promulgated under the ITA, all specific proposals to amend the ITA or the regulations promulgated under the ITA announced by or on behalf of the Canadian Minister of Finance prior to the date of this Annual Report and the current published administrative practices of the Canada Customs and Revenue Agency, or the Agency. It does not otherwise take into account or anticipate any changes in law or administrative practice nor any income tax laws or considerations of any province or territory of Canada or any jurisdiction other than Canada, which may differ from the Canadian federal income tax consequences described in this document.

Under the ITA and the Convention, dividends paid or credited, or deemed to be paid or credited, on the common stock to a U.S. person who owns less than 10% of the voting shares will be subject to Canadian withholding tax at the rate of 15% of the gross amount of those dividends or deemed dividends. If a U.S. person is a corporation and owns 10% or more of the voting shares, the rate is reduced from 15% to 5%. As described above and subject to specified limitations, a U.S. person may be entitled to credit against U.S. federal income tax liability for the amount of tax withheld by Canada.

Under the Convention, dividends paid to specified religious, scientific, charitable and similar tax exempt organizations and specified organizations that are resident and exempt from tax in the United States and that have complied with specified administrative procedures are exempt from this Canadian withholding tax.

A capital gain realized by a U.S. person on a disposition or deemed disposition of the common stock will not be subject to tax under the ITA unless the common stock constitute taxable Canadian property within the meaning of the ITA at the time of the disposition or deemed disposition. In general, the common stock will not be "taxable Canadian property" to a U.S. person if they are listed on a prescribed stock exchange, which includes The Toronto Stock Exchange, unless, at any time within the five-year period immediately preceding the dispositions, the U.S. person, persons with whom the U.S. person did not deal at arm's length, or the U.S. person together with those persons, owned or had an interest in or a right to acquire more than 25% of any class or series of our shares.

If the common stock are taxable Canadian property to a U.S. person, any capital gain realized on a disposition or deemed disposition of those common stock will generally be exempt from tax under the ITA by virtue of the Convention if the value of the common stock at the time of the disposition or deemed disposition is not derived principally from real property, as defined by the Convention, situated in Canada. The determination as to whether Canadian tax would be applicable on a disposition or deemed disposition of the common stock must be made at the time of the disposition or deemed disposition.

HOLDERS OF COMMON STOCK ARE URGED TO CONSULT THEIR OWN TAX ADVISORS TO DETERMINE THE PARTICULAR TAX CONSEQUENCES TO THEM, INCLUDING THE APPLICATION AND EFFECT OF ANY STATE, LOCAL OR FOREIGN INCOME AND OTHER TAX LAWS, OF THE ACQUISITION, OWNERSHIP AND DISPOSITION OF COMMON STOCK.

- 43 -

Item 12.

Certain Relationships and Related Transactions

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None of Enterra s directors or executive officers, nor any person who beneficially owns directly or indirectly or exercises control or direction over securities carrying more than 5% of the voting rights attaching to our shares of common stock, nor any known associate or affiliate of these persons had any material interest, direct or indirect in any transaction since January 1, 2001 which has materially affected Enterra, or in any proposed transaction which will materially affect Enterra, except as follows:

Consulting Agreement

Westlinks has entered into a Consulting Agreement with Wells Gray Resort & Resources Ltd. in October 2000 that ended in April 2001. Under the contract Thomas J. Jacobsen, the principal of Wells Gray Resort & Resources Ltd., was in charge of Westlinks drilling, completion and equipping projects, for consulting fees of $8,333 per month.

Item 13.

Exhibits And Reports On Form 10-KSB

Exhibits

Financial Statements

Audited Annual Financial Statements:	Page
Reports of Deloitte & Touche LLP and KPMG LLP Independent Accountants	F-1 and F-2
Consolidated Balance Sheets	F-3
Consolidated Statement of Income (Loss) and Retained Earnings	F-4
Consolidated Statement of Cash Flows	F-5
Notes to Consolidated Financial Statements	F-6 to F-18

(b) Exhibit List

Number

Exhibit

1.1	Form of Underwriting Agreement.
2.1	Amalgamation Agreement dated May 27, 1998 between Temba Resources Ltd. and PTR Resources Ltd. pursuant to which the Registrant was amalgamated under the Business Corporations Act (Alberta) on June 30, 1998.
2.2	Letter Agreement dated August 12, 1999 pursuant to which the Registrant acquired all of the issued and outstanding shares of 759795 Alberta Ltd.
2.3	Notice of Intention to File a Normal Course Issuer Bid.

3.1	Certificate of Amalgamation and attached Articles of Amalgamation of the Registrant dated and filed June 30, 1998.
3.2	By-laws of the Registrant.
4.1	Form of Warrant Trust Indenture between the Registrant and Montreal Trust Company of Canada providing for the issuance of the Warrants.
4.2	Form of Warrant Agreement between the Registrant and the Representatives providing for the issuance of the Underwriters' Warrants.
10.1	Credit Facility Letter Agreement between the Alberta Treasury Branches and the Registrant as Borrower dated April 19, 2000.
10.2	Promissory Notes dated June 5, 2000 granted by Westlinks to each of Glenn Russell, Patrick Williams Advisors, William J. Gordica, F. Jack Wright, Lawrence W. Underwood and Sapphire Capital Inc.
10.3	Purchase and Sale Agreement dated April 6, 2000 between Sabre Exploration Ltd. and the Registrant.
10.4	Purchase and Sale Agreement dated October 1, 2000 between the Registrant and Compton Petroleum Corporation.
10.5	Consulting Agreement dated October 13, 2000 between Westlinks Resources Ltd. and Wells Gray Resort & Resources Ltd.

10.6	Arrangement Agreement among Westlinks Resources Ltd. and 3779041Canada Ltd. and Big Horn Resources Ltd.
10.7	Information Circular and Proxy Statement for the Plan of Arrangement between Big Horn Resources Ltd. and Westlinks Resources Ltd.
21.1	Subsidiaries of the Registrant
99.1	Certification of Chief Executive Officer pursuant to 18 U.S.C.ss.1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2	Certification of Chief Financial Officer pursuant to 18 U.S.C.ss.1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K

On October 18, 2002 a Form 8-K was filed concerning the filing of a letter to shareholders.

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Within the 90 days prior to the date of this report, Enterra Energy Corp. carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive

Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures. The Company s disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in its periodic Securities and Exchange Commission ("SEC") filings is recorded, processed and reported within the time periods specified in the SEC s rules and forms. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company s periodic SEC filings.

Changes in Internal Controls

There were no significant changes in the Company s internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

- 45 -

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Enterra Energy Corp.

By: Luc Chartrand

Name: Luc Chartrand

Title: Chief Financial Officer

March 28, 2003

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Walter Dawson	Director	03/28/03
Reg J. Greenslade	Director, President and Chief Executive Officer	03/28/03
H.S. (Scobey) Hartley	Director	03/28/03
Doug Paul	Director	03/28/03
Norman G. Wallace	Director	03/28/03
Thomas J. Jacobsen	Director, Chief Operating Officer	03/28/03
Luc Chartrand	Chief Financial Officer	03/28/03

- 46 -

Consolidated Financial Statements of

ENTERRA ENERGY CORP.

AUDITORS REPORT TO THE SHAREHOLDERS

Year ended December 31, 2002

To the Shareholders of Enterra Energy Corp.:

We have audited the consolidated balance sheet of Enterra Energy Corp. as at December 31, 2002 and the consolidated statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards and auditing standards generally accepted in the United States of America. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2001 and for the year then ended were audited by other auditors who expressed an opinion without reservation on those consolidated financial statements in their report dated March 6, 2002.

(Signed) Deloitte & Touche

LLP

Chartered Accountants

Calgary, Canada

March 12, 2003

F-1

Consolidated Financial Statements of

ENTERRA ENERGY CORP.

AUDITORS REPORT TO THE SHAREHOLDERS

Year ended December 31, 2001

To the Shareholders of Enterra Energy Corp.:

We have audited the consolidated balance sheet of Enterra Energy Corp. as at December 31, 2001 and the consolidated statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards and auditing standards generally accepted in the United States of America. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Canadian generally accepted accounting principles vary in certain significant respects from accounting principles generally accepted in the United States. Application of accounting principles generally accepted in the United States would have affected results of operations for the year ended December 31, 2001 and shareholders equity as at December 31, 2001 to the extent summarized in note 16 to the consolidated financial statements.

(Signed) KPMG

LLP

Chartered Accountants

Calgary, Canada

March 6, 2002

F-2

Enterra Energy Corp.

Consolidated Balance Sheets

As at December 31

(Expressed in Canadian dollars)

	2002	2001
		(Restated note 6)
Assets		
Current assets		
Cash	$108,017	$43,364
Accounts receivable	7,314,050	6,296,639

Prepaid expenses and deposits	656,685	583,058
	8,078,752	6,923,061
Property and equipment (note 5)	94,354,313	73,139,497
Deferred financing charges (note 2)	284,040	-
	$102,717,105	$80,062,558
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$20,661,005	$8,989,389
Income taxes payable	155,424	163,103
Bank indebtedness (note 6)	24,436,640	18,408,904
Current portion of long-term debt (note 7)	808,917	-
	46,061,986	27,561,396
Provision for future abandonment and site restoration costs	934,857	751,088
Future income tax liability (note 8)	12,070,101	11,159,101
Long-term debt (note 7)	4,112,681	-
Deferred gain (note 13)	237,463	761,302
Series 1 preferred shares (note 11)	636,690	6,305,586
	64,053,778	46,538,473
Shareholders Equity		
Share capital (note 9)	29,665,075	29,568,263
Contributed surplus (note 9)	65,029	-
Retained earnings	8,933,223	3,955,822
	38,663,327	33,524,085
Hedging contracts (note 13)		
Commitments (note 14)		
Subsequent events (note 15)		
	$102,717,105	$80,062,558

Approved on behalf of the Board :

Reg Greenslade	Walter Dawson
Director	Director

See accompanying notes to consolidated financial statements

Enterra Energy Corp.

Consolidated Statements of Earnings and Retained Earnings

Years Ended December 31

(Expressed in Canadian dollars)

	2002	2001
Revenue		
Oil and gas	$25,745,676	$20,264,396
Expenses		
Royalties, net of ARTC	4,202,880	3,182,340
Production	6,017,921	5,829,613
General and administrative	1,682,773	565,270
Interest on long-term debt	1,235,872	589,169
Amortization of deferred financing charges (note 2)	390,800	-
Depletion, depreciation and future site restoration	9,306,500	6,869,912
	22,836,746	17,036,304
Earnings before the following	2,908,930	3,228,092
Restructuring charges	-	(929,037)
Gain on redemption of preferred shares (note 11)	3,111,471	-
Earnings before income taxes	6,020,401	2,299,055
Income taxes (note 8)		
Current	132,000	120,000
Future	911,000	562,000
	1,043,000	682,000
Net earnings	4,977,401	1,617,055
Retained earnings, beginning of year	3,955,822	2,338,767

Retained earnings, end of year	$8,933,223	$3,955,822
Earnings per share :		
Basic	$ 0.54	$ 0.23
Diluted	$ 0.53	$ 0.23

See accompanying notes to consolidated financial statements

Enterra Energy Corp.

Consolidated Statements of Cash Flows

Years Ended December 31

(Expressed in Canadian dollars)

	2002	2001
Cash provided by (used in) :		
Operations		
Net earnings	**$4,977,401**	$1,617,055
Add non-cash items :		
Depletion, depreciation and future site restoration	**9,306,500**	6,869,912
Future income taxes	**911,000**	562,000
Deferred gain	**-**	1,680,031
Amortization of deferred gain	**(523,839)**	(918,729)
Amortization of deferred financing charges	**390,800**	-
Gain on redemption of preferred shares	**(3,111,471)**	-
Funds from operations	**11,950,391**	9,810,269
Net change in non-cash working capital items:		
Accounts receivable	**(1,017,411)**	(1,371,654)
Prepaid expenses	**(73,627)**	(161,941)
Accounts payable and accrued liabilities	**11,671,616**	2,205,753
Income taxes payable	**(7,679)**	(1,153,068)
	22,523,290	9,329,359

Financing		
Bank indebtedness	**6,027,736**	1,055,904
Long-term debt	**4,704,098**	-
Issue of common shares, net of issue costs	**96,812**	5,457,625
Repurchase of shares	**(59,971)**	(753,300)
Deferred financing charges	**(549,840)**	-
Redemption of preferred shares	**(2,557,425)**	-
	7,661,410	5,760,229
Investing		
Property and equipment additions	**(35,881,256)**	(14,958,086)
Acquisition of Big Horn Resources Ltd.	**-**	(2,190,048)
Proceeds on disposal of property and equipment	**5,809,940**	1,700,500
Investments	**-**	422,000
Future abandonment and site restoration costs	**(48,731)**	(22,033)
	(30,120,047)	(15,047,667)
Increase in cash	**64,653**	41,921
Cash, beginning of year	**43,364**	1,443
Cash, end of year	**$ 108,017**	$ 43,364
Funds from operations per share:		
Basic	**$ 1.31**	$ 1.40
Future	**$ 1.27**	$ 1.40

During 2001, the Company paid $1,235,872 (2001 - $589,169) of interest on long-term debt and $132,000 (2001 - $120,000) of capital taxes.

See accompanying notes to consolidated financial statements

Enterra Energy Corp.

Notes to Consolidated Financial Statements

For the Years Ended December 31, 2002 and 2001

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1. Corporate history

Enterra Energy Corp. (the "Company" or "Enterra") was formed on June 30, 1998 by the amalgamation of Temba Resources Ltd. and PTR Resources Ltd. in a share-for-share exchange. The combination was recorded using the purchase method of accounting with Temba being identified as the acquirer.

Effective August 1, 2001 Enterra acquired 100% of the common shares of Big Horn Resources Ltd. ("Big Horn"), a junior oil and gas company listed on the Toronto Stock Exchange, by the way of a plan of arrangement. Consideration consisted of cash of $2,205,447 (not including acquisition costs) and the issuance of 3,496,436 common shares and 7,418,332 preferred shares. The terms of the Series 1 preferred shares are described in note 11. In addition, 460,915 Enterra options were issued in exchange for Big Horn options.

2. Significant accounting policies

These consolidated financial statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and US GAAP on these consolidated financial statements is disclosed in note 16. These consolidated financial statements include the accounts of Enterra and its subsidiary companies and partnerships in which a controlling interest is retained. All material intercompany accounts and transactions have been eliminated. Substantially all exploration, development and production activities related to our oil and gas business are conducted jointly with others and our accounts reflect only Enterra s proportionate interest.

(a) Petroleum and natural gas properties

The Company follows the "full cost" method of accounting for petroleum and natural gas properties. All costs related to the exploration for and the development of oil and gas reserves are capitalized into a single cost centre representing the Company 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.

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.

F-6

(b) Income taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities) and are measured using the currently enacted, or substantially enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized. Income tax expense or benefit is the sum of the Company s provision for current income taxes and the difference between the opening and ending balances of the future income tax assets and liabilities.

(c) Financial instruments

The estimated fair value of all financial instruments is based on quoted market prices and if not available, on estimates from third-party brokers or dealers. The carrying value cash, accounts receivable, deposit, bank indebtedness, accounts payable, accrued liabilities, long-term and preferred shares approximates their fair value. Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, as described in note 12. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instrument and the item designated as being hedged. The Company recognizes gains and losses in the same period as the hedged item. See note 13 for details about the Company s commodity hedging activities.

(d) Estimates and assumptions

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Actual results could differ from those estimates.

(e) Per share amounts

The Company follows the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

The weighted average number of common shares outstanding during the years ended December 31, 2002 and 2001 were 9,154,491 and 6,992,393, respectively. In computing diluted earnings per share 258,116 shares (2001 5,114 shares) were added to the weighted average number of common shares outstanding during the year as a result of the dilutive effect of stock options. See note 10 for a reconciliation of basic and diluted earnings per share.

(f) Stock-based compensation

Effective January 1, 2002 the Company prospectively adopted the new recommendations of the CICA with respect to the accounting for stock-based compensation and other stock-based payments. In accordance with the new standard, the Company elected to continue its policy that no compensation is recorded on the granting of employee stock options and consideration paid on the exercise of such options is recorded as share capital. In addition, the new standard requires a fair value based method of accounting for other stock-based payments. See notes 9(d) and 9(e) for additional information with regard to the methods and assumptions used in calculating the fair value of stock-based compensation.

F-7

(g) Revenue recognition

Revenue from the sale of oil and gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(h) Deferred financing charges

Deferred financing charges include costs related to the proposed financing mentioned in note 9(f) and costs related to the capital leases described in note 7. These costs include professional and consulting fees, travel costs, legal and accounting, and also include the $125,000 described in note 9(f). These costs are amortized over the remaining life of their related financial instruments.

(i) Comparative figures

The presentation of certain figures of the previous year has been changed to conform with the presentation adopted for the current year.

3. Business combination

Effective August 1, 2001 Enterra acquired 100% of the issued and outstanding shares of Big Horn Resources Ltd. Details of the acquisition are as follows:

Assets acquired:	
Current assets, excluding cash	$2,841,106
Property and equipment	46,874,349
	49,715,455
Liabilities assumed:	
Current liabilities	2,428,687
Bank indebtedness	8,950,000
Provision for future abandonment and site restoration costs	280,274
Future income tax liability	11,309,464
	22,968,425
Net non-cash assets acquired	26,747,030
Cash acquired	37,599

	$26,784,629
Consideration:	
Cash	$2,227,647
Preferred shares (7,418,336 issued)	6,305,586
Common shares (3,496,436 issued)	18,251,396
	$26,784,629

The consideration value attributed to the common shares contemplates an element related to the former stock options of Big Horn that were exchanged for stock options of the Company. However, this element was not considered significant for separate reporting.

4. Investments

Investments in Red Raven Resources Inc. and Raptor Capital Corporation with an amount of $422,000 were disposed of during 2001 as part of the severence amounts paid to former directors and officers of the Company.

F-8

5. Property and equipment

December 31, 2002

	Cost	Accumulated depletion and Depreciation	Net
Petroleum and natural gas properties	$ 112,657,277	$ 18,897,024	$ 93,760,253
Office furniture and equipment	1,077,988	483,928	594,060
	$ 113,735,265	$ 19,380,952	$ 94,354,313

December 31, 2001

	Cost	Accumulated depletion and Depreciation	Net
Petroleum and natural gas properties	$ 82,574,219	$ 9,939,258	$ 72,634,961
Office furniture and equipment	843,464	338,928	504,536

	$ 83,417,683	$ 10,278,186	$ 73,139,497

In conducting its 2001 ceiling test evaluation the Company followed generally accepted accounting principles which provide for a two-year exemption from write-down where the purchase price of reserves had been determined on a basis which provided a higher amount than the ceiling test value, and where the excess was not considered to represent a permanent impairment in the ultimate recoverable amount. If the two-year exemption had not been used, the Company would have taken a write-down of $8.1 million based on prices at December 31, 2001 of $22.05 per bbl of oil and $3.42 per mcf of gas. Enterra qualified for the exemption in connection of its acquisition of Big Horn in August 2001.

In conducting its ceiling test evaluation for 2002 the Company followed generally accepted accounting principles based on prices at December 31, 2002 of $45.89 per bbl of oil and $5.49 per mcf of gas. No write-down was required for 2002.

Included in the cost of the petroleum and natural gas properties are amounts for capitalized general and administrative expenses. These amounts were $1,450,900 in 2002 (2001 - $729,400).

At December 31, 2002 costs of undeveloped land of $3,967,000 (2001 - $8,053,000) were excluded from the calculation of depletion expense.

The Company estimates future abandonment and site restoration costs to be $4,114,000 at December 31, 2002 (2001 - $3,083,000) of which $232,500 (2001 - $242,000) has been accrued as a liability.

6. Bank indebtedness

Bank indebtedness represents the outstanding balance under a line of credit of $26,700,000 with the Alberta Treasury Branches. Drawings bear interest at 0.25% above the bank s prime lending rate. Security is provided by a first charge over all of the Company s assets. The balance is repayable on demand. While the loan is due on demand, the Company is not subject to scheduled repayments. This loan was classified as a long-term liability in the December 31, 2001 financial statements and has been restated into current liabilities in 2002. Effective for fiscal periods commencing January 1, 2002, the Company adopted the new CICA recommendation regarding Balance Sheet Classification of Callable Debt Obligations and Debt Obligations Expected to be Refinanced. All borrowings where the lender has a right to demand repayment within twelve months are required to be classified as current liabilities. The impact of this change has been to increase current liabilities by the amount of any such borrowings then in place. At December 31, 2002 this change has increased current liabilities by $24,436,640 (December 31, 2001 - $18,408,904).

F-9

7. Long-term debt

Assets secured with long-term debt are tangible oil and gas equipment with a cost of $5,217,500. These assets are subject to the depletion provisions described in note 2(a).

Balances as at December 31, 2002

Description	**Principal**	**Less**	**Net**

	outstanding	current portion	Balance
Capital lease bearing interest at 8.605%, repayable monthly at $88,802 plus applicable taxes. The lease term is for 60 months, due October 1, 2007, with a purchase option of $1,000,000	$ 4,747,775	$ 678,636	$ 4,069,139
Capital lease bearing interest at 12.15%, repayable monthly at $4,448 plus applicable taxes. The lease term is 24 months due December 19, 2004 with a purchase option of $100	91,042	47,500	43,542
Note payable bearing interest at 8%, repayable monthly at $7,190. The lease term is 15 months due December 20, 2003.	82,781	82,781	-
	$ 4,921,598	$ 808,917	$ 4,112,681

8. Income taxes

The income tax provision is calculated by applying Canadian federal and provincial statutory tax rates to pre-tax income with adjustments as set out in the following table:

	2002	2001
Earnings before income taxes	$6,020,401	$2,299,055
Combined federal and provincial income tax rate	42.12%	42.60%
Computed income tax provision	2,535,793	979,397
Increase (decrease) resulting from:		
Resource allowance	(1,627,200)	(1,211,828)
Non-deductible Crown royalties, net of ARTC	1,313,089	781,332
Non-taxable portion of capital gain	(1,310,552)	-
Capital taxes	132,000	120,000
Other	(130)	13,099
	$1,043,000	$682,000

The components of the net future income tax liability at December 31 were as follows:

	2002	2001
Future income tax assets:		
Share issue costs	$ 647,597	$ 916,709
Future abandonment and site restoration	295,321	239,973

Deferred gain	75,015	243,236
	1,017,933	1,399,918
Future income tax liabilities:		
Property, plant and equipment	13,088,034	12,559,019
Net future income tax liability	$ 12,070,101	$ 11,159,101

F-10

At December 31, 2002 the Company had approximately $62,629,000 (2001 - $43,152,000) of tax pools available to reduce future taxable income.

9. Share capital

(a) Authorized:

Unlimited number of voting common shares without nominal or par value.

Unlimited number of preferred shares issuable in one or more series

(b) Issued:

	Number of common shares	Amount
Balance, December 31, 2000	4,595,139	5,031,846
Issued for cash on exercise of options	43,500	99,450
Issued for cash pursuant to public offerings	1,035,000	7,081,024
Issued on acquisition of property and equipment	213,047	1,300,000
Issued on acquisition of Big Horn Resources Ltd.	3,496,436	18,251,396
Shares repurchased	(232,500)	(753,300)
Issue costs incurred, net of income tax benefit of $1,118,251	-	(1,442,153)
Balance, December 31, 2001	9,150,622	$ 29,568,263
Issued for cash on exercise of options	44,511	171,127
Shares repurchased	(18,808)	(74,315)
Balance, December 31, 2002	9,176,325	$29,665,075

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Contributed surplus is made up of the following amounts:

Balance at January 1, 2002	$ -
Value assigned to 100,000 warrants described in note 9(f)	125,000
Loss related to shares repurchased during year	(59,971)
Balance at December 31, 2002	$ 65,029

(c) Options:

The Company granted options to purchase common shares to directors, officers, employees and consultants. Each option permits the holder to purchase one common share of Enterra at the stated exercise price. All options vest over 4 years and are exercisable on a cumulative basis over 5 years. At the time of grant, the exercise price is equal to the market price. The following options have been granted:

	Number of Options	**Weighted-average exercise price**
Outstanding at December 31, 2000	430,500	$5.76
Options granted	990,000	$4.41
Options exercised	(43,500)	$2.29
Options cancelled	(577,000)	$6.15
Outstanding at December 31, 2001	800,000	$4.00
Options granted	232,000	$5.30
Options exercised	(44,511)	$3.84
Options cancelled	(115,786)	$4.03
Options outstanding at December 31, 2002	871,703	$4.35

Of the 232,000 options granted during 2002, 55,000 were granted to non-employees (2001 119,500). There were 871,703 options outstanding at December 31, 2002. Compensation expense related to these options amounted to $18,000 for 2002. These options are exercisable at prices ranging from $4.00 to $8.85 and expire on dates ranging from November 1, 2006 to December 9, 2007, as follows:

Outstanding Options			**Exercisable Options**	
	Weighted	**Weighted**		**Weighted**
Number of Options	**Average**	**Average**	**Number of Options**	**Average**

	(thousands)	Exercise Price ($/option)	Years to Expiry (years)	(thousands)	Exercise Price ($/option)
$4.00 to $5.99	811	$ 4.11	4.0	327	$ 4.00
$6.00 to $8.85	61	$ 7.31	4.7	-	-
	872			327	

(d) Estimated fair value of stock options

We determine the estimated fair value of stock options issued in 2002 and 2001 using the Generalized Black-Scholes model under the following assumptions:

	2002	2001
Weighted-average fair value ($/option)	$ 2.83	$ 0.76
Risk-free interest rate (%)	5.0	5.0
Estimated hold period prior to exercise (years)	5	5
Volatility in the price of Enterra s common shares (%)	55	30

(e) Pro forma net income fair value based method of accounting for stock options

The following shows pro forma net income and earnings per common share had we applied the fair-value

based method of accounting to stock options issued in 2002 and 2001:

	2002	2001
Net earnings (in 000 s)		
As reported	$ 4,977	$ 1,617
Less fair value of stock options to employees	(47)	(27)
Pro Forma	$ 4,930	$ 1,590
Earnings Per Common Share ($/share)		
Basic as Reported	$ 0.54	$ 0.23
Pro Forma	$ 0.54	$ 0.23
Diluted as Reported	$ 0.53	$ 0.23
Pro Forma	$ 0.52	$ 0.23

(f) Warrants:

	Number of Warrants	Weighted average price
Balance, December 31, 2000	-	-
Issued pursuant to public offering	1,000,000	US$ 3.50
Issued pursuant to underwriters agreement	100,000	US$ 5.40
Balance, December 31, 2001	1,100,000	US$ 3.67
Expired	(1,000,000)	US$ 3.50
Issued pursuant to debt financing	100,000	US$ 2.60
Balance, December 31, 2002	200,000	US$ 4.00

F-12

On January 17, 2001, the Company completed a secondary public offering in the United States. The offering consisted of 1,000,000 units of one common share and one share purchase warrant for U.S. $4.55 per unit. The share purchase warrants were exercisable at US$ 3.50 per share. They expired on May 17, 2002. The 100,000 share purchase warrants related to the underwriters agreement are exercisable at U.S. $5.40 per share starting January 16, 2002 and may be exercised for a four year period thereafter. On March 28, 2002 the Company agreed to issue 300,000 share purchase warrants to an arm s length U.S.-based consulting firm in connection with a potential debt financing in the United States. The warrants are to have a two-year term and are subject to different pricing (100,000 warrants at US$2.60, 100,000 at US$3.30 and 100,000 at US$4.00). The US$2.60 warrants have vested since the execution in May 2002 of a non-binding letter of intent relating to the proposed financing. The US$3.30 and US$4.00 warrants are to vest only on the successful closing and funding of the proposed financing. A value of $125,000 was assigned to the 100,000 warrants at US$2.60. This value was determined using the Black Scholes Option Pricing model using an interest rate of 5% and a volatility factor of 50%. The $125,000 was credited to the Company s contributed surplus account.

10. Reconciliation of Earnings per Share Calculations:

For the year ended December 31, 2002

	Net Earnings	Weighted Average Shares Outstanding	Per Share
Basic	$4,977,401	9,154,491	$0.54
Options and warrants assumed exercised		803,999	
Shares assumed purchased		(545,883)	

Diluted	$4,977,401	9,412,607	$0.53

Excluded from the above calculation are 61,000 options which were "out-of-the-money" in 2002.

For the year ended December 31, 2001

	Net Earnings	Weighted Average Shares Outstanding	Per Share
Basic	$1,617,055	6,992,393	$0.23
Options and warrants assumed exercised		46,027	
Shares assumed purchased		(40,913)	
Diluted	$1,617,055	6,997,507	$0.23

11. **Series 1 preferred shares:**

At December 31, 2002 there were 749,047 Series 1 preferred shares outstanding (December 31, 2001 7,418,336). These shares are non-voting. They are transferable. Subsequent to August 16, 2002 holders of these shares are entitled to receive a fixed cumulative dividend of $0.085 per share per annum, payable quarterly. These shares are redeemable at any time by the Company for $0.85 per share. Holders of these shares may require the Company to redeem all or any of these shares, at $0.85 per share. There is no market for these shares and none is expected to develop. On March 26, 2002 the Company purchased 6,123,870 of its Series 1 preferred shares for $2.3 million, resulting in a gain on redemption of $2,905,290. The purchase was paid for with cash of $1,750,000 and a note payable of $550,000. This note was repaid for $325,000 on August 15, 2002 resulting in an additional gain, net of legal costs, of $206,181. A dividend of $22,549 was paid on the preferred shares in 2002. This amount is included in interest expense.

F-13

12. Financial instruments

Due to the nature of its operation, the Company is exposed to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. The Company recognizes these risks and manages its operations to minimize the exposure to the extent practical and, to a lesser extent, using derivative instruments. The company uses non-exchange traded forwards, swaps and options, which may be settled in cash or by delivery of the physical commodity. Management monitors the Company s exposure to the above risks and regularly reviews its derivative activities and all outstanding positions.

(i) Commodity prices risks

The Company s most significant market risk exposure relates to crude oil prices fluctuation. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent the Company is also exposed to natural gas price movements. Natural gas prices are generally influenced by North American supply and demand, and to a lesser extent local market conditions.

(ii) Foreign currency exchange risk:

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices.

(iii) Credit risk:

A substantial portion of the Company s accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company s natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

(iv) Interest rate risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2002, we had $24,436,640 of indebtedness bearing interest at floating rates and $4,921,598 of long-term debt bearing interest at fixed rates.

13.

Hedging contracts

During 2002 and 2001, the Company entered into the following hedges to minimize its exposure to fluctuations in commodity prices relating to its future sales of crude oil and gas. The contracts are as follows:

(a) The Company entered into a physical zero cost collar arrangement during 2001 which provides a floor price of US$20 per barrel and a ceiling price of US$24 per barrel for 500 barrels of oil per day. The contract is effective from November 1, 2001 through April 30, 2002.

(b) In July 2002, the Company entered into a physical zero cost collar arrangement with a floor price of US$22 per barrel and a ceiling price of US$28 per barrel for 500 barrels of oil per day. The contract is effective from October 1, 2002 through March 31, 2003. At December 31, 2002 this contract had an estimated negative market value of $216,000.

F-14

(c) In July 2002, the Company entered into two contracts to deliver natural gas. One is for 1,500 mcf per day, priced at CA$4.60 per mcf. The other is for 1,500 mcf per day, priced at CA$4.45 per mcf. Both contracts are effective from November 1, 2002 through March 31, 2003. At December 31, 2002 these contracts had an estimated negative market value of $369,000.

Effective January 31, 2001, the Company settled a fixed price contract eliminating the requirement to deliver set physical quantities of oil at fixed prices. Upon the cancellation of the contract the Company received approximately $1,680,000, which will be recognized over the term of the contract. At December 31, 2002 the remaining deferred gain related to this settlement was $237,463 (2001 - $761,302).

14. Commitments

The Company has commitments for the following payments over the next five years:

	2003	2004	2005	2006	Thereafter 2007
Capital lease obligations	$1,118,994	$1,118,994	$1,070,068	$1,065,620	$1,799,215
Note payable	86,284				
Rental payments re-office space	447,357	429,854	165,121	114,894	
	$1,652,635	$1,548,848	$1,235,189	$1,180,514	$1,799,215

15. Subsequent events

(a) Subsequent to December 31, 2002 the Company sold some non-core oil and gas properties for proceeds of $4.3 million.

(b) Subsequent to December 31, the Company entered into several contracts to deliver 2,000 barrels of oil per day for the period April 1, 2003 and December 31, 2003. The prices and volumes are as follows:

Volumes (in barrels per day)	**Price (in US dollars)**
1,000	US$29.60
250	US$29.71
250	US$29.50
500	US$29.80

F-15

16. United States accounting principles and reporting

The Company s consolidated financial statements have been prepared in Canadian Dollars and in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"), which differ in some respects from those in the United States ("U.S. GAAP"). Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

(a) Property and equipment:

The Company performs 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 the Company realized a U.S. GAAP ceiling test write-down of $17.5 million (after tax). There was no such write-down at December 31, 2002. As a result of the 2001 write-down, the 2002 depletion expense under U.S. GAAP was lower by $2.1 million (after tax).

(b) Provision for future abandonment and site restoration:

Under U.S. GAAP, the provision for future abandonment and site restoration costs is recorded as a reduction of property and equipment.

(c) Financial instruments:

FAS 133 requires the company to recognize all derivative instruments on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met.

The Company routinely enters into physical commodity contracts to minimize its exposure to fluctuations in commodity prices relating to its future sales of crude oil. Such contracts often meet the criteria of FAS 133 as derivatives but are generally eligible for the normal purchase and sale exception under FAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities An Amendment of FAS 133". Contracts that meet the criteria of this exception are not recognized on the balance sheet as either an asset or a liability measured at fair value.

At December 31, 2002 and 2001, under Canadian GAAP, the Company had a deferred gain resulting from the settlement of a fixed price contract, which is being amortized over the term of the contract. Under U.S. GAAP, this gain, net of related income taxes, would be included in income as it did not qualify for hedge accounting under SFAS 133.

(d) Stock-based compensation:

Under U.S. GAAP, SFAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. During 2001, the Company granted 119,500 stock options to non-employees. Had compensation cost for these stock options been determined based on their fair market value at the grant dates of the awards, the Company s pre-tax income for the year would have decreased by $90,294. The weighted average fair market value of options granted to non-employees in 2002 was $0.76 per option. The fair value of each option granted was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: risk-free interest rate of 5%, volatility of 30% and expected life of five years. After January 1, 2002, stock option issued to non-employee resulted in the same accounting treatment under both Canadian and US GAAP.

F-16

(e) Cash flows

Under Canadian GAAP, companies are permitted to present a sub-total prior to changes in non-cash working capital within operating activities. This information is perceived to be useful information for various users of the financial statements and is commonly presented by Canadian public companies. Under U.S. GAAP, this sub-total is not permitted to be shown and would be removed in the statements of cash flows for all periods presented. In addition, cash flow from operations per share figures would not be presented under U.S. GAAP.

(f) Balance sheets:

The adjustments using U.S. GAAP would result in the following changes to the consolidated balance sheets of the Company:

	2002		**2001**	
	Canadian GAAP	**U.S. GAAP**	**Canadian GAAP**	**U.S. GAAP (restated)**
Assets				
Current assets	$ 8,078,752	$ 8,078,752	$ 6,923,061	$ 6,923,061
Capital assets (a)(b)	94,354,313	68,307,526	73,139,497	43,692,704
Deferred financing charges	284,040	284,040	-	-
	$ 102,717,105	$ 76,670,318	$ 80,062,558	$ 50,615,765
Liabilities				
Current liabilities	46,061,986	46,061,986	$ 9,152,492	$ 27,651,690
Long-term debt (c)	4,112,681	4,112,681	18,408,904	-
Future income taxes (a)(d)	12,070,101	2,485,695	11,159,101	285,850

Provision for future site restoration (b)	934,857	-	751,088	-
Deferred gain (d)	237,463	-	761,302	-
Series 1 preferred shares	636,690	636,690	6,305,586	6,305,586
	64,053,778	53,297,052	46,538,473	34,243,126
Shareholders equity				
Share capital	29,665,075	29,665,075	29,568,263	29,568,263
Contributed surplus	65,029	155,323	-	-
Retained earnings (deficit)	8,933,223	(6,447,132)	3,955,822	(13,195,624)
	$ 38,663,327	23,373,266	33,524,085	16,372,639
	$ 102,717,105	$ 76,670,318	$ 80,062,558	$ 50,615,765

F-17

(g) Income statements:

The adjustments using U.S. GAAP would result in the following changes to the consolidated financial statements of the Company:

	2002	**2001**
Net earnings (loss) under Canadian GAAP	$ 4,977,401	$ 1,617,055
Less gain on redemption of preferred shares, net of income tax	(3,111,471)	-
Net earnings before extraordinary items	1,865,930	1,617,055
Adjustments:		
Full cost accounting (a)	-	(28,695,705)
Related income taxes	-	11,159,101
Hedging gain (c)	(523,839)	761,302
Related income taxes	220,641	(324,315)
Depletion expense (a)	3,583,775	-
Related income taxes	(1,509,486)	-
Stock-based compensation (d)	-	(90,294)
Related income taxes	-	38,465

Net earnings (loss) before extraordinary items under U.S. GAAP	3,637,021	(15,534,391)
Extraordinary items:		
Gain on redemption of preferred shares, net of income tax	3,111,471	-
Net earnings under U.S. GAAP	$ 6,748,492	($ 15,534,391)
Net earnings (loss) per share:		
Basic	$ 0.74	($ 2.22)
Diluted	$ 0.72	($ 2.22)
Net impact per share relating to extraordinary items:		
Basic	$ 0.34	-
Diluted	$ 0.33	-