ABRAXAS PETROLEUM CORP
Form 10-K/A
July 22, 2003

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A
AMENDMENT NO. 1

(Mark One)

[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

[ ]TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 0-19118

ABRAXAS PETROLEUM CORPORATION

(Exact name of Registrant as specified in its charter)

Nevada	74-2584033
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

500 N. Loop 1604 East, Suite 100
San Antonio, Texas 78232
(Address of principal executive offices)

Registrant's telephone number, including area code (210) 490-4788

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:
Common Stock, par value $.01 per share

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or 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__

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not 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-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act) [ ] Yes [X] No

The aggregate market value of the voting stock (which consists solely of shares of common stock) held by nonaffiliates of the registrant as of June 30, 2002, based upon the closing per share price of $0.75, was approximately $17,414,180 on such date.

The number of shares of the issuer's common stock, par value $.01 per share, outstanding as of March 5, 2003 was 35,622,096 shares of which 28,328,651 shares were held by non-affiliates.

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Documents Incorporated by Reference: Portions of the registrant's Proxy Statement relating to the 2003 Annual Meeting of Shareholders to be held on May 29, 2003 have been incorporated by reference herein (Part III).

2

Explanatory Note

This amendment is being filed to reflect the restatement of the Company's consolidated financial statements, as discussed in Note 20 thereto, and other information related to such restated financial statements. Except for Items 1 and 2 of Part I, Items 6, 7 and 8 of Part II and Item 15 of Part IV, no other information included in the original report on Form 10-K is amended by this Form 10-K/A.

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ABRAXAS PETROLEUM CORPORATION

FORM 10-K/A
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FORWARD-LOOKING INFORMATION

We make forward-looking statements throughout this document. Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we "believe," "expect" or "anticipate" will occur or what we "intend" to do, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this document is generally located in the material set forth under the headings "Risk Factors," "Business," and "Management's Discussion and Analysis of Financial Condition and Results of Operations" but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- our high debt level;
- our ability to raise capital;
- our limited liquidity;
- economic and business conditions;
- price and availability of alternative fuels;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- our success in development, exploitation and exploration activities;
- planned capital expenditures;
- prices for crude oil and natural gas;
- declines in our production of crude oil and natural gas;
- our acquisition and divestiture activities;
- results of our hedging activities; and
- other factors discussed elsewhere in this document.

PART I

Item 1. Business

General

Abraxas Petroleum Corporation is an independent energy company engaged primarily in the acquisition, exploration, exploitation and production of crude oil and natural gas. Our principal means of growth has been through the acquisition and subsequent development and exploitation of producing properties. As a result of our historical acquisition activities, we believe that we have a

substantial inventory of low risk exploration and development opportunities, the development of which is critical to the maintenance and growth of our current production levels. We seek to complement our acquisition and development activities by selectively participating in exploration projects with experienced industry partners.

In January 2003, we completed the following transactions:

- The closing of the sale of the capital stock of our wholly owned subsidiaries Canadian Abraxas Petroleum Limited, referred to herein as Canadian Abraxas, and Grey Wolf Exploration Inc., referred to herein as Old Grey Wolf, to a Canadian royalty trust for approximately $138 million.

- The closing of a new senior secured credit agreement consisting of a term loan facility of $4.2 million and a revolving credit facility of

up to $50 million with an initial borrowing base of $49.9 million, of which $42.5 million was used to fund the exchange offer described below and the remaining availability will fund the continued development of our existing crude oil and natural gas properties.

- The closing of an exchange offer, pursuant to which Abraxas paid $264 in cash and issued $610 principal amount of new 11 1/2 % Secured Notes due 2007, Series A, referred to herein as New Notes, and 31.36 shares of Abraxas common stock for each $1,000 in principal amount of the outstanding 11 1/2 % Senior Secured Notes due 2004, Series A, and 11 1/2 % Senior Notes due 2004, Series D, issued by Abraxas and Canadian Abraxas, which were tendered and accepted in the exchange offer. An aggregate of approximately $179.9 million in principal amount of the notes were tendered in the exchange offer and the remaining $11.1 million of notes not tendered were redeemed.

- The repayment of Abraxas' 12 7/8% Senior Secured Notes due 2003, principal amount of $63.5 million, plus accrued interest.

- The repayment of Old Grey Wolf's senior secured credit facility with Mirant Canada Energy Capital Ltd. (Mirant Canada Facility) in the amount of approximately $46.3 million.

These transactions are more fully described below under the caption "Recent Events."

Our principal areas of operation are Texas and western Canada. At December 31, 2002, we owned interests in 548,819 gross acres (422,874 net acres), and operated properties accounting for approximately 88% of our PV-10, affording us substantial control over the timing and incurrence of operating and capital expenditures. At December 31, 2002 estimated total proved reserves were 166.5 Bcfe with an aggregate PV-10 of $254.9 million. Subsequent to the transactions described in "Recent Events" our reserves were reduced by 54.0 Bcfe with an aggregate PV-10 of $118.3 million.

PV-10 means estimated future net revenue discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the Securities and Exchange

Commission. A Mcf is one thousand cubic feet of natural gas. MMcf is used to designate one million cubic feet of natural gas and Bcf refers to one billion cubic feet of natural gas. Mcfe means thousands of cubic feet of natural gas equivalents, using a conversion ratio of one barrel of crude oil to six Mcf of natural gas. MMcfe means millions of cubic feet of natural gas equivalents and Bcfe means billions of cubic feet of natural gas equivalents. MMBtu means million British Thermal Units. The term Bbl means one barrel of crude oil and MBbls is used to designate one thousand barrels of crude oil or natural gas liquids.

Recent Events

We recently completed a series of transactions designed to reduce our indebtedness, improve our ability to meet our debt service obligations and provide us with working capital necessary to develop our existing crude oil and natural gas properties. As a result of these transactions, which we sometimes refer to in this document as the financial restructuring, we have reduced the principal amount of our overall outstanding long-term debt from approximately $300 million at December 31, 2002 to approximately $156.4 million in principal amount at January 23, 2003, and have reduced our annual cash interest payments from approximately $34 million to approximately $4 million, assuming that, as required under the new senior secured credit agreement, Abraxas issues additional New Notes in lieu of cash interest payments. After giving effect to the financial restructurings on January 23, 2003, the principal amount of our outstanding New Notes and new senior secured credit agreement was approximately $156.4 million ($109.7 million in New Notes and $46.7 related to the new senior secured credit agreement). Due to the accounting treatment under accounting principles generally accepted in the United States of America for financial restructurings, the reported carrying value of the New Notes and new senior secured credit agreement will be approximately $175 million ($128.6 million related to the New Notes). The transactions comprising the financial restructuring are summarized below.

See Notes 2 and 3 of Notes to Consolidated Financial Statements in Item 8 for further information regarding the sale of Canadian Abraxas and Old Grey Wolf and the impact of the exchange offer on our outstanding notes at year end 2002.

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Sale of Stock of Canadian Abraxas and Old Grey Wolf

On January 23, 2003, Abraxas completed the sale to a wholly owned subsidiary of PrimeWest Energy Inc. of all of the outstanding capital stock of two of Abraxas' former wholly-owned subsidiaries, Canadian Abraxas and Old Grey Wolf, for approximately $138 million before net adjustments of $3.4 million. Under the terms of the agreement with PrimeWest, we have retained certain oil and gas properties formerly held by Canadian Abraxas and Old Grey Wolf, including all of Canadian Abraxas' and Old Grey Wolf's undeveloped acreage existing at the time of the sale, which includes all of our interests in producing and undeveloped acreage in the Ladyfern area. These assets have been contributed to a new wholly-owned subsidiary, Grey Wolf Exploration, Inc., which we refer to herein as New Grey Wolf. Portions of this undeveloped acreage will be developed by PrimeWest and New Grey Wolf under a farmout arrangement.

Abraxas used the proceeds from the sale of the capital stock of Canadian Abraxas and Old Grey Wolf for the following purposes:

- to pay fees and expenses of the sale of Canadian Abraxas and Old Grey Wolf of approximately $2.5 million;

- to redeem our 12 7/8% Senior Secured Notes, Series A, referred to herein as first lien notes, at 100% of their principal amount, plus accrued and unpaid interest, for approximately $66.4 million; and

- to pay approximately $19.4 million of the cash portion of the exchange offer described below.

In addition, upon the closing of the sale, Old Grey Wolf repaid all of its outstanding indebtedness of approximately $46.3 million, under the Mirant Canada facility.

Exchange Offer

Contemporaneously with the closing of the sale of Canadian Abraxas and Old Grey Wolf, Abraxas completed an exchange offer, pursuant to which it offered to exchange cash and securities for all of the then outstanding 11 1/2% Senior Secured Notes due 2004, Series A, referred to herein as second lien notes, and 11 1/2% Senior Notes due 2004, Series D, referred to herein as old notes, issued by Abraxas and Canadian Abraxas ($52.6 million is carried on Canadian Abraxas). In exchange for each $1,000 principal amount of notes tendered in the exchange offer, tendering note holders received:

- cash in the amount of $264;

- an 11 1/2% Secured Note due 2007, Series A, with a principal amount equal to $610; and

- 31.36 shares of Abraxas common stock.

At the time the exchange offer was made, there were approximately $190.2 million of the second lien notes and $801,000 of the old notes outstanding. Holders of approximately 94% of the aggregate outstanding principal amount of the second lien notes and old notes tendered their notes for exchange in the offer. Pursuant to the procedures for redemption under the applicable historical indenture provisions, the remaining 6% of the aggregate outstanding principal amount of the second lien notes and old notes were redeemed at 100% of the principal amount plus accrued and unpaid interest, for approximately $11.5 million ($11.1 million in principal and $0.4 million in interest) and the indentures for the second lien notes and old notes were duly discharged. In connection with the exchange offer, Abraxas made cash payments of approximately $47.5 million and issued approximately $109.7 million in principal amount of New Notes and 5,642,699 shares of Abraxas common stock. Fees and expenses incurred in connection with the exchange offer were approximately $3.8 million, of which $967,000 was charged to expense in 2002 and is included in financing cost in the statement of operations and the balance will be charged to expense in 2003 as the cost are incurred.

New Notes

The New Notes will accrue interest from the date of issuance, at a fixed annual rate of 11 1/2%, payable in cash semi-annually on each May 1 and November 1, commencing May 1, 2003, provided that, if we fail, or are not permitted pursuant to our new senior secured credit agreement or the intercreditor agreement between the trustee under the indenture for the New Notes and the lenders under the new senior secured credit agreement, to make such cash

interest payments in full, we will pay such unpaid interest in kind by the issuance of additional notes with a principal amount equal to the amount of accrued and unpaid cash interest on the notes plus an additional 1% accrued interest for the applicable period. Upon an event of default, interest will accrue at an annual rate of 16.5%. The New Notes are guaranteed by all of Abraxas' current subsidiaries, Sandia Oil & Gas Corp., Sandia Operating Corp., Wamsutter Holdings, Inc., Western Associated Energy Corporation, Eastside Coal Company, Inc., and New Grey Wolf, and will be guaranteed by all of Abraxas' future subsidiaries. The New Notes are secured by a second lien or charge on all of the Company's current and future assets, including, but not limited to, its crude oil and natural gas properties. Under the terms of the New Notes, we are required, to the extent permitted, to pay down debt under the new senior secured credit agreement and, if permitted, the New Notes, with our cash flow which is not required to pay our capital expenditures or make cash interest and tax payments.

Redemption of First Lien Notes

On January 24, 2003, we completed the redemption of 100% of our outstanding 12 7/8% Senior Secured Notes, Series A, or first lien notes, with approximately $66.4 million of the proceeds from the sale of Canadian Abraxas and Old Grey Wolf utilized to retire $63.5 million of our first lien notes outstanding, plus accrued interest of $2.9 million. Under the terms of the indenture for the first lien notes, we had the right to redeem the first lien notes at 100% of the outstanding principal amount of the notes, plus accrued and unpaid interest to the date of redemption, and to discharge the indenture upon call of the first lien notes for redemption and deposit of the redemption funds with the trustee. We exercised these rights on January 23, 2003 and upon the discharge of the indenture, the trustee released the collateral securing our obligations under the first lien notes.

New Senior Secured Credit Agreement

Contemporaneously with the closing of the exchange offer and the sale of Canadian Abraxas and Old Grey Wolf, Abraxas entered into a new senior secured credit agreement providing a term loan facility and a revolving credit facility as described below. Subject to earlier termination on the occurrence of events of default or other events, the stated maturity date for both the term loan facility and the revolving credit facility is January 22, 2006. Outstanding amounts under both facilities bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 4.5%. Any amounts in default under the term loan facility will accrue interest at an additional 4%. At no time will the amounts outstanding under the new senior secured credit agreement bear interest at a rate less than 9%.

Term Loan Facility. Upon closing of the new senior secured credit agreement, Abraxas borrowed $4.2 million pursuant to a term loan facility, all of which was used to make cash payments in connection with the financial restructuring. Accrued interest under the term loan facility will be capitalized and added to the outstanding principal amount of the term loan facility until maturity. As of March 5, 2003, Abraxas owed $4.2 million under the term loan facility.

Revolving Credit Facility. Lenders under the new senior secured credit agreement have provided a revolving credit facility to Abraxas with a maximum borrowing base of up to $50 million. Our current borrowing base under the revolving credit facility is $49.9 million, subject to adjustments based on periodic calculations and mandatory prepayments under the senior secured credit agreement. Portions of accrued interest under the revolving credit facility may be capitalized and added to the principal amount of the revolving credit facility. As of March 5, 2003, we had borrowed $42.5 million under the revolving

credit facility.

Business Strategy

Our primary business objectives are to increase reserves, production and cash flow through the following:

- Low Cost Operations. We seek to maintain low lease operating and general and administrative expenses ("G&A expenses") per Mcfe by operating a majority of our producing properties and by maintaining a high rate of production on a per well basis. As a result of this strategy, we have achieved per unit lease operating and G&A expenses that compare favorably with our peer companies.

- Exploitation of Existing Properties. We will continue to allocate a portion of our operating cash flow to the exploitation of our proved oil and natural gas properties. We believe that the proximity of our undeveloped reserves to existing production makes development of these properties less risky and more cost-effective than other drilling opportunities available to us. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion. Abraxas' inventory of development opportunities is considerable and growing, our ability to exploit that inventory will depend on our ability to raise additional capital and on our discretionary cash flow, which in turn is highly dependent on future crude oil and natural gas prices.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of, and demand for, crude oil and natural gas. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our crude oil and natural gas production and the level of such production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other crude oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices of crude oil and natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenue, profitability and cash flow from operations. You should read the discussion under "Risk Factors - Crude oil and natural gas prices and their volatility could adversely our revenues, cash flows and profitability" and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies" for more information relating to the effects on us of decreases in crude oil and natural gas prices.

In order to manage our exposure to price risks in the marketing of our crude oil and natural gas, from time to time we have entered into fixed price delivery contracts, financial swaps and crude oil and natural gas futures contracts as hedging devices. To ensure a fixed price for future production, we may sell a futures contract and thereafter either (i) make physical delivery of crude oil or natural gas to comply with such contract or (ii) buy a matching futures contract to unwind our futures position and sell our production to a customer. These contracts may expose us to the risk of financial loss in certain circumstances, including instances where production is less than expected, our customers fail to purchase or deliver the contracted quantities of crude oil or

natural gas, or a sudden, unexpected event materially impacts crude oil or natural gas prices. These contracts may also restrict our ability to benefit from unexpected increases in crude oil and natural gas prices. You should read the discussion under "Management's Discussion and Analysis of Financial Condition And Results of Operations -- Liquidity and Capital Resources," and "Quantitative and Qualitative Disclosures about Market Risk; Commodity Price Risk" for more information regarding our historical hedging activities.

Substantially all of our crude oil and natural gas is sold at current market prices under short-term arrangements , as is customary in the industry. During the year ended December 31, 2002, three purchasers accounted for approximately 77% of our United States crude oil and natural gas sales and one customer accounted for approximately 80% of our crude oil and natural gas sales in Canada. We believe that there are numerous other companies available to purchase our crude oil and natural gas and that the loss of one or more of these purchasers would not materially affect our ability to sell crude oil and natural gas. The prices we realize for the sale of our crude oil and natural gas are subject to our hedging activities. You should read the discussion under "Management's Discussion and Analysis of Financial Condition And Results of Operations -- Liquidity and Capital Resources" and "Quantitative and Qualitative

Disclosures about Market Risk; Commodity Price Risk" for more information regarding our historical hedging activities.

Risk Factors

Our reduced operating cash flow resulting from the sale of Canadian Abraxas and Old Grey Wolf may put significant strain on our liquidity and cash position. Our reduced operating cash flow and resulting limited liquidity has caused us, and the limitations imposed by the new senior secured credit agreement and the New Notes will cause us, to reduce capital expenditures, including exploration, exploitation and development projects. These reductions will limit our ability to replenish our depleting reserves, which could negatively impact our cash flow from operations and results of operations in the future. In addition, under the terms of the New Notes, we are required, to the extent permitted, to pay down debt under the new senior secured credit agreement and, if permitted, the New Notes, with our cash flow which is not required to pay our capital expenditures or make cash interest and tax payments.

The effects of our reduced operating cash flow will be exacerbated by our high level of debt, which will affect our operations in several important ways, including:

- A substantial amount of our cash flow from operations could be required to make principal and interest payments on our outstanding indebtedness and may not be available for other purposes, including developing our properties;

- The covenants contained in the indenture governing the New Notes and in the new senior secured credit agreement will limit our ability to borrow additional funds or to dispose of assets or use the proceeds of any asset sales and may affect our flexibility in planning for, and reacting to, changes in our business; and

- Our debt level may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, interest payments, scheduled principal payments, general corporate purposes or other purposes.

Our limited liquidity and restrictions on uses of cash dictated by both the new senior secured credit agreement and the New Notes, combined with our high debt levels, may hinder our ability to satisfy the substantial capital requirements related to our operations. The success of our future operations will require us to make substantial capital expenditures for the exploitation, development, exploration and production of crude oil and natural gas.

Under the terms of the new senior secured credit agreement and the New Notes, Abraxas is subject to cash and expenditures covenants including limitations on capital expenditures. These limitations imposed on Abraxas by the new senior secured credit agreement and the New Notes will have the effect of limiting our ability to develop our crude oil and natural gas properties because much of our cash flow may be used for debt service. As a result, our ability to replace production may be limited. You should read the discussion under "Our ability to replace production with new reserves is highly dependent on acquisitions or successful development and exploration activities" for more information regarding the risks associated with limitations on our ability to develop our crude oil and natural gas properties.

Hedging transactions may limit our potential gains. Under the terms of the new senior secured credit agreement, we are required to maintain commodity price hedging positions on not less than 25% and not more than 75% of our estimated production for a rolling six-month period. On January 23, 2003, we entered into a collar option agreement with respect to 5,000 MMBtu per day, or approximately 25% of our production, at a call price of $6.25 per MMBtu and a put price of $4.00 per MMBtu, for the calendar months of February through July 2003. In February 2003, we entered into a second hedging agreement related to 5,000 MMBtu which provides for a floor price of $4.50 per MMBtu for the calendar months of March 2003 through February 2004.

We cannot assure you that our hedging 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, and have in the past limited, additional revenues from price increases. In addition, such transactions may expose us to risks of financial loss under certain circumstances, such as:

- production being less than expected; or
- price differences between delivery points for our production and those in our hedging agreements increasing.

In 2000, 2001 and 2002, we experienced hedging losses of $20.2 million, $12.1 million and $3.2 million, respectively.

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, exploitation 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. While we

have had some success in pursuing these activities, we have not been able to fully replace the production volumes lost from natural field declines and property sales. We have implemented a number of measures to conserve our cash resources, including postponement of exploration and development projects. However, while these measures will conserve our cash resources in the near term, they will also limit our ability to replenish our depleting reserves, which could negatively impact our cash flow from operations in the future. The terms of our senior secured credit agreement and new secured notes limit our capital expenditures which will further limit our ability to replenish our reserves and replace production. Further, in addition to the effects of our limited liquidity, our operations may be curtailed, delayed or cancelled by other factors, such as title problems, weather, compliance with governmental regulations, mechanical problems or shortages or delays in the delivery of equipment. We cannot assure you that our exploration and development activities will result in increases in reserves.

Use of our net operating loss carryforwards may be limited. At December 31, 2002, Abraxas had, subject to the limitation discussed below, $166.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2003 through 2022 if not utilized. At December 31, 2002, Abraxas had approximately $1.0 million of net operating loss carryforwards for Canadian tax purposes. These carryforwards will expire from 2003 through 2009 if not utilized. In connection with January 2003 transactions described in Note 2, in Notes to Consolidated Financial Statements, Item 8, certain of the loss carryforwards may be utilized.

As to a portion of the U.S. net operating loss carryforwards, the amount of such carryforwards that we can use annually is limited under U.S. tax law. Additionally, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, Abraxas has established a valuation allowance of $39.7 million and $99.1 million for deferred tax assets at December 31, 2001 and 2002, respectively.

Crude oil and natural gas prices and their volatility could adversely affect our revenue, cash flows, profitability and growth. Our revenue, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for crude oil and natural gas. Natural gas prices affect us more than crude oil prices because most of our production and reserves are natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. In addition, we may have ceiling limitation write-downs when prices decline. During the second quarter of 2002, we had a ceiling limitation write down of approximately $116.0 million. Lower prices may also reduce the amount of crude oil and natural gas that we can produce economically.

We cannot predict future crude oil and natural gas prices. Factors that can cause price fluctuations include:

o changes in supply and demand for crude oil and natural gas;

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o weather conditions;

o the price and availability of alternative fuels;

o political and economic conditions in oil producing countries, especially those in the Middle East; and

- overall economic conditions.

In addition to decreasing our revenue and cash flow from operations, low or declining crude oil and natural gas prices could have additional material adverse effects on us, such as:

- reducing the overall volumes of crude oil and natural gas that we can produce economically;
- causing a ceiling limitation write-down;
- increasing our dependence on external sources of capital to meet our liquidity requirements; and
- impairing our ability to obtain needed equity capital.

Lower crude oil and natural gas prices increase the risk of ceiling limitation write-downs. We use the full cost method to account for our crude oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop crude oil and natural gas properties. Under full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a "ceiling limit" which is 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 exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and earnings. The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher crude oil and natural gas prices may have increased the ceiling applicable to the subsequent period.

At June 30, 2002, our net capitalized costs of crude oil and natural gas properties exceeded the present value of our estimated proved reserves by $138.7 million ($28.2 million on the U.S. properties and $110.5 million on the Canadian properties). These amounts were calculated considering June 30, 2002 prices of $26.12 per Bbl for crude oil and $2.16 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. Subsequent to June 30, 2002, commodity prices increased in Canada and we utilized these increased prices in calculating the ceiling limitation write-down. The total write-down was approximately $116.0 million. At December 31, 2002, our net capitalized cost of crude oil and natural gas properties did not exceed the present value of our estimated reserves, due to increased commodity prices during the fourth quarter and, as such, no further write-down was recorded. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

Estimates of our proved reserves and future net revenue are uncertain and inherently imprecise. This annual report contains estimates of our proved crude oil and natural gas reserves and the estimated future net revenue from such reserves. The process of estimating crude oil and natural gas reserves is complex and involves decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Therefore, these estimates are imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of

recoverable crude oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this annual report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this annual report is the current market value of our estimated crude oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the period of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the end of the year of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the crude oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

The estimates of our reserves are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of crude oil and natural gas reserves, future net revenue from proved reserves and the PV-10 thereof for the crude oil and natural gas properties described in this annual report are based on the assumption that future crude oil and natural gas prices remain the same as crude oil and natural gas prices at December 31, 2002. The sales prices as of such date used for purposes of such estimates were $29.69 per Bbl of crude oil, $18.89 per Bbl of NGLs and $3.79 per Mcf of natural gas. This compares with $18.26 per Bbl of crude oil, $16.29 per Bbl of NGLs and $2.16 per Mcf of natural gas as of December 31, 2001. These estimates also assume that we will make future capital expenditures of approximately $59.5 million in the aggregate, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

We have experienced recurring net losses. The following table shows the losses we had in 1998, 1999, 2001 and 2002:

	Years Ended December 31,			
	1998	1999	2001	2002
Net (loss)	$(84.0)	$(36.7)	$(19.7)	$ (118.5)

While we had net income in 2000 of $8.4 million, if the significant gain on the sale of an interest in a partnership were excluded, we would have experienced a net loss for the year of $(25.5) million. We cannot assure you that we will become profitable in the future.

The marketability of our production depends largely upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. The marketability of our production depends in part upon processing facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by U.S. federal and state and Canadian regulation of crude oil and natural gas production and transportation, general economic conditions, and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on us could be substantial and adversely affect our ability to produce and market crude oil and natural gas.

Our Canadian operations are subject to the risks of currency fluctuations and in some instances economic and political developments. We conduct operations in Canada. The expenses of such operations are payable in Canadian dollars while most of the revenue from crude oil and natural gas sales is based upon U.S. dollar price indices. As a result, Canadian operations are subject to the risk of fluctuations in the relative values of the Canadian and U.S. dollars. We are also required to recognize foreign currency translation gains or losses related to any debt issued by our Canadian subsidiary because the debt is denominated in U.S. dollars and the functional currency of such subsidiary is the Canadian dollar. Our foreign operations may also be adversely affected by local political and economic developments, royalty and tax increases and other foreign laws or policies, as well as U.S. policies affecting trade, taxation and investment in other countries.

We depend on our key personnel. We depend to a large extent on Robert L.G. Watson, our Chairman of the Board, President and Chief Executive Officer, for our management and business and financial contacts. The unavailability of Mr. Watson could have a materially adverse effect on our business. Mr. Watson has a three-year employment contract with Abraxas commencing on December 21, 1999, which automatically renews thereafter for successive one-year periods unless Abraxas gives 120 days notice prior to the expiration of the original term or any extension thereof of its intention not to renew the employment agreement. Our success is also dependent upon our ability to employ and retain skilled technical personnel. While we have not experienced difficulties in employing or retaining such personnel, our failure to do so in the future could adversely affect our business.

Risks Related to Our Industry

Our operations are subject to numerous risks of crude oil and natural gas drilling and production activities. Our 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, work boats 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 holes 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, natural 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 which 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.

We face significant competition for obtaining additional natural gas supplies for gathering and processing operations, for marketing NGLs, residue gas, helium, condensate and sulfur, and for transporting natural gas and liquids. Our principal competitors include major integrated oil companies and their marketing affiliates and national and local gas gatherers, brokers, marketers and distributors of varying sizes, financial resources and experience. Certain competitors, such as major crude oil and natural gas companies, have

capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

Our crude oil and natural gas operations are subject to various U.S. federal, state and local and Canadian federal and provincial governmental regulations that materially affect our operations. Matters regulated include discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of crude oil and natural gas, these agencies have restricted the rates of flow of crude oil and natural gas wells below actual production capacity. Federal, state, provincial and local laws regulate production, handling, storage, transportation and disposal of crude oil and natural gas, by-products from crude oil and natural gas and other substances and materials produced or used in connection with crude oil and natural gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Regulation of Crude Oil and Natural Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our operations are affected from time to time in varying degrees by political developments and federal, state, provincial and local laws and regulations. In particular, crude oil and natural gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental, and other laws relating to the petroleum industry, by changes in such laws and by constantly changing administrative regulations.

Price Regulations

In the past, maximum selling prices for certain categories of crude oil, natural gas, condensate and NGLs in the United States were subject to significant federal regulation. At the present time, however, all sales of our crude oil, natural gas, condensate and NGLs produced in the United States under private contracts may be sold at market prices. Congress could, however, reenact price controls in the future. If controls that limit prices to below market rates are instituted, our revenue would be adversely affected.

Crude oil and natural gas exported from Canada is subject to regulation by the National Energy Board ("NEB") and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. Crude oil and natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB license and Governor in Council approval.

The provincial governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from these provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and marketing considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of the United States, Canada and Mexico became effective. In the context of energy resources, Canada remains free to determine whether exports to the U.S. or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports. The Texas Railroad Commission has recently become the lead agency for Texas for coordinating permits governing Texas to Mexico cross border pipeline projects. The availability of selling natural gas into Mexico may substantially impact the interstate natural gas market on all producers in the coming years.

United States Natural Gas Regulation

Historically, the natural gas industry as a whole has been more heavily regulated than the crude oil or other liquid hydrocarbons market. Most regulations focused on transportation practices. In the recent past interstate pipeline companies in the United States generally acted as wholesale merchants by purchasing natural gas from producers and reselling the natural gas to local distribution companies and large end users. Commencing in late 1985, the Federal Energy Regulatory Commission (the "FERC") issued a series of orders that have had a major impact on interstate natural gas pipeline operations, services, and rates, and thus have significantly altered the marketing and price of natural gas. The FERC's key rule making action, Order No. 636 ("Order 636"), issued in April 1992, required each interstate pipeline to, among other things, "unbundle" its traditional bundled sales services and create and make available on an open and nondiscriminatory basis numerous constituent services (such as gathering services, storage services, firm and interruptible transportation services, and standby sales and natural gas balancing services), and to adopt a new ratemaking methodology to determine appropriate rates for those services. To the extent the pipeline company or its sales affiliate markets natural gas as a merchant, it does so pursuant to private contracts in direct competition with all of the sellers, such as us; however, pipeline companies and their affiliates were not required to remain "merchants" of natural gas, and most of the interstate pipeline companies have become "transporters only," although many have affiliated marketers. Order 636 and related FERC orders have resulted in increased competition within all phases of the natural gas industry. We do not believe that Order 636 and the related restructuring proceedings affect us any differently than other natural gas producers and marketers with which we compete.

Transportation pipeline availability and cost are major factors affecting the production and sale of natural gas. Our physical sales of natural gas are affected by the actual availability, terms and cost of pipeline transportation. The price and terms for access onto the pipeline transportation systems remain subject to extensive Federal regulation. Although Order 636 does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to and use of the necessary transportation facilities and how we and our competitors sell natural gas in the marketplace. The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines, although some appeals remain pending and the FERC continues to review and modify its regulations regarding

the transportation of natural gas. For example, the FERC has recently begun a broad review of its natural gas transportation regulations, including how its regulations operate in conjunction with state proposals for natural gas marketing restructuring and in the increasingly competitive marketplace for all post-wellhead services related to natural gas.

In recent years the FERC also has pursued a number of other important policy initiatives which could significantly affect the marketing of natural gas in the United States. Some of the more notable of these regulatory initiatives include:

(1) a series of orders in individual pipeline proceedings articulating a policy of generally approving the voluntary divestiture of interstate pipeline owned gathering facilities by interstate pipelines to their affiliates (the so-called "spin down" of previously regulated gathering facilities to the pipeline's nonregulated affiliates).

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(2) Order No. 497 involving the regulation of pipelines with marketing affiliates.

(3) various FERC orders adopting rules proposed by the Gas Industry Standards Board which are designed to further standardize pipeline transportation tariffs and business practices.

(4) a notice of proposed rulemaking that, among other things, proposes (a) to eliminate the cost-based price cap currently imposed on natural gas transactions of less than one year in duration, (b) to establish mandatory "transparent" capacity auctions of short-term capacity on a daily basis, and (c) to permit interstate pipelines to negotiate terms and conditions of service with individual customers.

(5) issuance of Policy Statements regarding Alternate Rates and Negotiated Terms and Conditions of Service covering (a) the pricing of long-term pipeline transportation services by alternative rate mechanism options, including the pricing of interstate pipeline capacity utilizing market-based rates, incentive rates, or indexed rates, and (b) investigating of whether FERC should permit pipelines to negotiate the terms and conditions of service, in addition to rates of service.

(6) a notice of proposed rulemaking that proposes generic procedures to expedite the FERC's handling of complaints against interstate pipelines with the goals of encouraging and supporting consensual resolutions of complaints and organizing the complaint procedures so that all complaints are handled in a timely and fair manner.

Several of these initiatives are intended to enhance competition in natural gas markets, although some, such as "spin downs," may have the adverse effect of increasing the cost of doing business on some in the industry, including us, as a result of the geographic monopolization of those facilities by their new, unregulated owners. As to all of these FERC initiatives, the ongoing, or, in some instances, preliminary and evolving nature of these regulatory initiatives makes it impossible at this time to predict their ultimate impact on our business. However, we do not believe that these FERC initiatives will affect us any differently than other natural gas producers and marketers with which we compete.

Since Order 636, FERC decisions involving onshore facilities have been more liberal in their reliance upon traditional tests for determining what facilities are "gathering" and therefore exempt from federal regulatory control. In many

instances, what was once classified as "transmission" may now be classified as "gathering." We ship certain of our natural gas through gathering facilities owned by others, including interstate pipelines, under existing long term contractual arrangements. Although these FERC decisions have created the potential for increasing the cost of shipping our natural gas on third party gathering facilities, our shipping activities have not been materially affected by these decisions.

In summary, all of the FERC activities related to the transportation of natural gas have resulted in improved opportunities to market our physical production to a variety of buyers and market places, while at the same time increasing access to pipeline transportation and delivery services. Additional proposals and proceedings that might affect the natural gas industry in the United States are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The crude oil and natural gas industry historically has been very heavily regulated; thus there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue indefinitely into the future.

State and Other Regulation

All of the jurisdictions in which we own producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units on an acreage basis and the density of wells which may be drilled and the unitization or pooling of crude oil and natural gas properties. In this regard, some states and provinces allow the forced pooling or integration of tracts to facilitate exploration while other states and provinces rely on voluntary pooling of lands and leases. In addition, state and provincial conservation laws establish maximum rates of production from crude oil and natural gas wells, generally

prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. Some states, such as Texas and Oklahoma, have, in recent years, reviewed and substantially revised methods previously used to make monthly determinations of allowable rates of production from fields and individual wells. The effect of all of these conservation regulations is to limit the speed, timing and amounts of crude oil and natural gas we can produce from our wells, and to limit the number of wells or the location at which we can drill.

State and provincial regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements, but does not generally entail rate regulation. In the United States, natural gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under Order 636. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the State's more active review of rates, services and practices associated with the gathering and transportation of natural gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

For those operations on U.S. Federal or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies. In addition, in the United States, the Minerals Management Service ("MMS") has recently issued a final rule to clarify or severely limit the types of costs that are deductible transportation costs for purposes of royalty valuation of production sold off the lease. In particular, MMS will not allow deduction of costs associated with marketer fees, cash out and other pipeline imbalance penalties, or long-term storage fees. Further, the MMS has been engaged in a process of promulgating new rules and procedures for determining the value of crude oil produced from federal lands for purposes of calculating royalties owed to the government. The crude oil and natural gas industry as a whole has resisted the proposed rules under an assumption that royalty burdens will substantially increase. We cannot predict what, if any, effect any new rule will have on our operations.

Canadian Royalty Matters

In addition to Canadian federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil 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. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed preference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced.

From time to time the governments of Alberta and British Columbia, the provinces where almost all of New Grey Wolf's production is located, have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging crude oil and natural gas exploration or enhanced planning projects. All of New Grey Wolf's production is from oil and gas rights which have been granted by the Provinces.

The Province of Alberta requires the payment from lessees of oil and gas rights of annual rental payments as well as royalty payments. Regulations made pursuant to the Mines and Minerals Act (Alberta) provide various incentives for exploring and developing crude oil reserves in Alberta. Crude oil produced from horizontal extensions commenced at least five years after the well was originally spudded may qualify for a royalty reduction. An 8,000 cubic meters exemption is available to production from a well that has not produced for a 12-month period prior to January 31, 1993 or 24 months following such date. In addition, crude oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992, is entitled to a 12-month royalty exemption (to a maximum of CDN $1 million). Crude oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government classifies conventional crude oil into three categories, being Old Oil, New Oil and Third Tier Oil. Each have a base royalty rate of 10%. The rate caps on the categories are 25% for oil from crude oil pools discovered after September 30, 1992, being the Third Tier Oil, 30% for oil

from pools or pool extensions discovered after April 1, 1974, from wells drilled or deepened after October 31, 1991 or from reactivated wells and which are not Third Tier Oil, and 35% for Old Oil.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown, subject to various incentives, is between 15% or 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory gas wells spudded or deepened after July 1, 1985 and before June 1, 1988 are eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of crude oil or natural gas is entitled to credit against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("ARTC") program. The ARTC program is based on a price-sensitive formula, and the ARTC rate currently varies between 75% for prices for crude oil at or below CDN $100 per cubic meter and 35% for prices above CDN $210 per cubic meter. The ARTC rate is currently applied to a maximum of CDN $2.0 million of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Producers of crude oil and natural gas in British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of crude oil and natural gas produced from Crown and freehold lands respectively. British Columbia also classifies conventional crude oil into the three categories of Old Oil, New Oil and Third Tier Oil. The amount payable as a royalty in respect of crude oil depends on the vintage of the crude oil (whether it was produced from a pool discovered before or after October 31, 1975) or a pool in which no well was completed on June 1, 1998), the quantity of crude oil produced in a month and the value of the crude oil. Crude oil produced from a discovery well may be exempt from the payment of a royalty for the first 36 months of production to a maximum production of 11,450 m3. The royalty payable on natural gas is determined by a sliding scale based on a classification of the gas based on whether it is conservation gas (gas associated with marketed oil production) and by drilling and land lease date and on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Conservation gas has a minimum royalty of 8%. The royalty rate ranges from between 9% and 27% for wells drilled on lands issued after May 31, 1998 and before January 1, 2003 and completed within 5 years of the date the lands were issued and between 12% and 27% for wells spudded after May 31, 1998 on lands where rights had been issued as of May 31, 1998.

Environmental Matters

Our operations are subject to numerous federal, state, provincial and local laws and regulations controlling the generation, use, storage, and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment in connection with drilling, production, and natural gas

processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as use of pits and plugging of abandoned wells; restrict injection of liquids into subsurface strata that may contaminate groundwater; and impose substantial liabilities for pollution resulting from our operations. Environmental permits required for our operations may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on us as well as the

crude oil and natural gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

In the United States, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund," and comparable state statutes impose strict, joint, and several liability on certain classes of persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and companies that generated, disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is common for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize imposition of substantial civil and criminal penalties for failing to prevent surface and subsurface pollution, as well as to control the generation, transportation, treatment, storage and disposal of hazardous waste generated by crude oil and natural gas operations. Although CERCLA currently contains a "petroleum exclusion" from the definition of "hazardous substance," state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including crude oil cleanups. In addition, although RCRA regulations currently classify certain oilfield wastes which are uniquely associated with field operations as "non-hazardous," such exploration, development and production wastes could be reclassified by regulation as hazardous wastes thereby administratively making such wastes subject to more stringent handling and disposal requirements.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Our operations are also impacted by

regulations governing the disposal of naturally occurring radioactive materials ("NORM"). We must comply with the Clean Air Act and comparable state statutes which prohibit the emissions of air contaminants, although a majority of our activities are exempted under a standard exemption. Moreover, owners, lessees and operators of crude oil and natural gas properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from, and are usually causes of action based on negligence, trespass, nuisance, strict liability and fraud.

United States federal regulations also require certain owners and operators of facilities that store or otherwise handle crude oil, such as us, to prepare and implement spill prevention, control and countermeasure plans and spill response plans relating to possible discharge of crude oil into surface waters. The federal Oil Pollution Act ("OPA") contains numerous requirements relating to prevention of, reporting of, and response to crude oil spills into waters of the United States. For facilities that may affect state waters, OPA requires an operator to demonstrate $10 million in financial responsibility. State laws mandate crude oil cleanup programs with respect to contaminated soil.

Our Canadian operations are also subject to environmental regulation pursuant to local, provincial and federal legislation which generally require operations to be conducted in a safe and environmentally responsible manner. Canadian environmental legislation provides for restrictions and prohibitions relating to the discharge of air, soil and water pollutants and other substances produced in association with certain crude oil and natural gas industry operations, and environmental protection requirements, including certain conditions of approval and laws relating to storage, handling, transportation and disposal of materials or substances which may have an adverse effect on the environment. Environmental legislation can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders.

Certain federal environmental laws that may affect us include the Canadian Environmental Assessment Act which ensures that the environmental effects of projects receive careful consideration prior to licenses or permits being issued, to ensure that projects that are to be carried out in Canada or on federal lands do not cause significant adverse environmental effects outside the jurisdictions in which they are carried out, and to ensure that there is an opportunity for public participation in the environmental assessment process; the Canadian Environmental Protection Act ("CEPA") which is the most comprehensive federal environmental statute in Canada, and which controls toxic substances (broadly defined), includes standards relating to the discharge of air, soil and water pollutants, provides for broad enforcement powers and remedies and imposes significant penalties for violations; the National Energy Board Act which can impose certain environmental protection conditions on approvals issued under the Act; the Fisheries Act which prohibits the depositing of a deleterious substance of any type in water frequented by fish or in any place under any condition where such deleterious substance may enter any such water and provides for significant penalties; the Navigable Waters Protection Act which requires any work which is built in, on, over, under, through or across any navigable water to be approved by the Minister of Transportation, and which attracts severe penalties and remedies for non-compliance, including removal of the work.

In Alberta, environmental compliance has been governed by the Alberta

Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition to consolidating a variety of environmental statutes, the AEPEA also imposes certain new environmental responsibilities on crude oil and natural gas operators in Alberta. The AEPEA sets out environmental standards and compliance for releases, clean-up and reporting. The Act provides for a broad range of liabilities, enforcement actions and penalties.

We are not currently involved in any administrative, judicial or legal proceedings arising under domestic or foreign federal, state, or local environmental protection laws and regulations, or under federal or state common law, which would have a material adverse effect on our financial position or results of operations. Moreover, we maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

We believe that we have obtained and are in compliance with all material environmental permits, authorizations and approvals.

Title to Properties

As is customary in the crude oil and natural gas industry, we make only a cursory review of title to undeveloped crude oil and natural gas leases at the time we acquire them. However, before drilling commences, we require a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our crude oil and natural gas properties, some of which are subject to immaterial encumbrances, easements and restrictions. The crude oil and natural gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.

Employees

As of March 5, 2003, we had 48 full-time employees in the United States, including 3 executive officers, 3 non-executive officers, 1 petroleum engineer, 1 geologist, 6 managers, 1 landman, 12 secretarial and clerical personnel and 21 field personnel. Additionally, we retain contract pumpers on a month-to-month basis. We retain independent geological and engineering consultants from time to time on a limited basis and expect to continue to do so in the future.

As of March 5, 2003, New Grey Wolf had 13 full-time employees, including 3 executive officers, 1 non-executive officer, 2 petroleum engineers, 2 geologists, 1 geophysicist and, 4 technical and clerical personnel in Canada.

Item 2. Properties

Primary Operating Areas

Texas

Our U.S. operations are concentrated in South and West Texas with over 99%

of the PV-10 of our U.S. crude oil and natural gas properties at December 31, 2002 located in those two regions. We operate 94% of our wells in Texas. Operations in South Texas are concentrated along the Edwards trend in Live Oak and Dewitt Counties, the Frio/Vicksburg trend in San Patricio County and the Wilcox trend in Goliad County. In total in South Texas we own an average 88% working interest in 44 wells with average daily production of 291 net Bbls of crude oil and NGLs and 8,177 net Mcf of natural gas per day for the year ended December 31, 2002. As of December 31, 2002 we had estimated net proved reserves in South Texas of 31,103 Mmcfe (83% natural gas) with a PV-10 of $47.2 million, 70% of which was attributable to proved developed reserves. Our West Texas operations are concentrated along the deep Devonian/Ellenberger formations and shallow Cherry Canyon sandstones in Ward County, the Spraberry trend in Midland County and in the Sharon Ridge Clearfork Field in Scurry County. We have entered into a farmout agreement with EOG Resources Inc. whereby EOG earned a 75% working interest in Abraxas' then existing Montoya acreage by paying Abraxas $2.5 million and paying 100% of the cost of the first five wells, the last of which came on line in December 2002. EOG remains under a continuous development clause, however Abraxas will be responsible for its pro-rata share of the drilling and development costs going forward. Two wells are planned for 2003. In total in West Texas we own an average 75% working interest in 157 wells with average daily production of 389net Bbls of crude oil and NGLs and 6,814 net Mcf of natural gas per day for the year ended December 31, 2002. As of December 31, 2002, we had estimated net proved reserves in West Texas of 65,957 Mmcfe (80% natural gas) with a PV-10 of $62.7 million, 39% of which was attributable to proved developed reserves. During 2002, we drilled a total of 3 new wells (1.06 net) in Texas with a 67% success rate.

Wyoming

We currently hold over 60,000 contiguous acres in the Powder River Basin in east central Wyoming. The Company has drilled and operates 5 wells in Converse and Niobrara counties that were completed in the Turner and Niobrara formations. We own a 100% working interest in these wells that produced an average of 43 net barrels of crude oil per day in 2002. As of December 31, 2002 we had estimated net proved producing reserves in Wyoming of 91,791 barrels of crude oil with a PV-10 of $427,000.

Western Canada

We own properties in western Canada, consisting primarily of natural gas reserves and undeveloped acreage in the provinces of Alberta and British Columbia. Our Alberta properties are in two concentrated areas; the Caroline field, 60 miles northwest of Calgary and the Peace River Arch area in northwestern Alberta. We have entered into a farmout agreement with PrimeWest in connection with the sale of Canadian Abraxas and Old Grey Wolf (See "Recent Events") to jointly develop these areas in the future. Our other Canadian operations are located in the Ladyfern area of northeast British Columbia. In this area we participated in six wells being drilled during 2002 with a 50% success rate. As of December 31, 2002 Canadian Abraxas and Grey Wolf had estimated net proved reserves of 68.8 Bcfe (88% natural gas) with a PV-10 of $144.5 million of which 93% was attributable to proved developed reserves. As of December 31, 2002, giving effect to the transactions which occurred in January 2003, New Grey Wolf had estimated net proved reserves, of 14.9 Bcfe (91% natural gas) with a PV-10 of $26.3 million, 61% of which was attributable to proved developed reserves. For the year ended December 31, 2002, the Canadian properties produced an average of approximately 740.5 net Bbls of crude oil and NGLs per day and 27,345.6 net Mcf of natural gas per day. During 2002, we drilled a total of 20 new wells (15.7 net) in Canada with a 90% success rate.

Exploratory and Developmental Acreage

Our principal crude oil and natural gas properties consist of non-producing and producing crude oil and natural gas leases, including reserves of crude oil and natural gas in place. The following table indicates our interest in developed and undeveloped acreage as of December 31, 2002:

	Developed and Undeveloped Acreage			
	As of December 31, 2002			
	Developed Acreage (1)		Undeveloped Acreage (2)	
	Gross Acres(3)	Net Acres(4)	Gross Acres (3)	Net Acres (4)
Canada (5)	84,335	49,429	367,315	285,827
Texas	24,775	19,911	10,881	10,029
Wyoming	3,200	3,200	58,311	54,478
Total	112,310	72,540	436,507	350,334

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(1) Developed acreage consists of acres spaced or assignable to productive wells.

(2) Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas, regardless of whether or not such acreage contains proved reserves.

(3) Gross acres refers to the number of acres in which we own a working interest.

(4) Net acres represents the number of acres attributable to an owner's proportionate working interest and/or royalty interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).

(5) Includes 73,840 gross (43,997 net) developed acres and 15,097 gross (8,288 net) undeveloped acres that were sold in connection with the sale of Canadian Abraxas and Old Grey Wolf in January 2003, see Item 1. "Business - Recent Events".

Productive Wells

The following table sets forth our total gross and net productive wells expressed separately for crude oil and natural gas, as of December 31, 2002:

	Productive Wells (1)
	As of December 31, 2002

State/Country	Crude Oil		Natural Gas	
	Gross(2)	Net(3)	Gross(2)	Ne
Canada (4)	243.0	5.6	121.0	6
Texas	139.0	111.3	62.0	4
Wyoming	5.0	5.0	-	
Total	387.0	121.9	183.0	11

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(1) Productive wells are producing wells and wells capable of production.
(2) A gross well is a well in which we own an interest. The number of gross wells is the total number of wells in which we own an interest.
(3) A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of our fractional working interest owned in gross wells.

(4) Includes 228.0 gross (4.3 net) crude oil wells and 114.0 gross (65.0 net) natural gas wells that were sold in connection with the sale of Canadian Abraxas and Old Grey Wolf in January 2003, see Item 1. "Business - Recent Events".

Reserves Information

The crude oil and natural gas reserves of the U.S. operations only have been estimated as of January 1, 2003, January 1, 2002, and January 1, 2001, by DeGolyer and MacNaughton, of Dallas, Texas. The reserves of the Canadian operations as of January 1, 2002 and January 1, 2001 have been estimated by McDaniel and Associates Consultants Ltd. of Calgary, Alberta. The January 1, 2003 reserves attributable to the Canadian operations were estimated internally. Crude oil and natural gas reserves, and the estimates of the present value of future net revenues there from, were determined based on then current prices and costs. Reserve calculations involve the estimate of future net recoverable reserves of crude oil and natural gas and the timing and amount of future net revenues to be received there from. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain.

The following table sets forth certain information regarding estimates of our crude oil, natural gas liquids and natural gas reserves as of January 1, 2001, January 1, 2002 and January 1, 2003:

	Estimated Proved Reserves		
	Proved Developed	Proved Undeveloped	Total Proved
As of January 1, 2001			
Crude oil (MBbls)	3,866	1,407	5,273
NGLs (MBbls)	3,135	436	3,571

Natural gas (MMcf)	119,737	71,590	191,327
As of January 1, 2002			
Crude oil (MBbls)	1,980	1,170	3,150
NGLs (MBbls)	3,067	585	3,652
Natural gas (MMcf)	111,243	77,514	188,757
As of January 1, 2003 (1)			
Crude oil (MBbls)	1,782	1,317	3,099
NGLs (MBbls)	1,222	284	1,506
Natural gas (MMcf)	90,374	48,458	138,832

Reserves on a Mcf equivalent at December 31, 2002 were 146.5 Bcfe. Crude oil and natural gas liquids are converted to a Mcf equivalent (Mcfe) on the basis of 1 Bbl of crude oil and natural gas liquid equals 6 Mcf of natural gas.

1. Reserves as of January 1, 2003 include 67 MBbls of crude oil, 1,079 MBbls of NGLs, and 47,066 MMcf of natural gas that were sold in connection with the sale of Canadian Abraxas and Old Grey Wolf in January 2003, see "Business - Recent Events".

The process of estimating crude oil and natural gas reserves is complex and involves decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Therefore, these estimates are imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this annual report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this annual statement is the current market value of our estimated crude oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the year of the estimate, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the Company's financial statements. As of December 31, 2001, the Company's net capitalized costs of crude oil and natural gas properties exceeded the present value of its estimated proved reserves by $38.9 million on U.S. properties. This amount was calculated considering 2001 year-end prices of $19.84 per Bbl for crude oil and $2.57 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. The Company did not adjust its capitalized costs for its U.S. properties because subsequent to December 31, 2001, crude oil and natural gas prices increased such that capitalized costs for its U.S. properties did not exceed the present value of the estimated proved crude oil and natural gas

reserves for its U.S. properties as determined using increased realized prices on March 22, 2002 of $24.16 per Bbl for crude oil and $2.89 per Mcf for natural

gas.

At June 30, 2002, our net capitalized costs of crude oil and natural gas properties exceeded the present value of our estimated proved reserves by $138.7 million ($28.2 million on the U.S. properties and $110.5 million on the Canadian properties). These amounts were calculated considering June 30, 2002 prices of $26.12 per Bbl for crude oil and $2.16 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. Subsequent to June 30, 2002, commodity prices increased in Canada and we utilized these increased prices in calculating the ceiling limitation write-down. The total write-down was approximately $116.0 million. At December 31, 2002, our net capitalized cost of crude oil and natural gas properties did not exceed the present value of our estimated reserves, due to increased commodity prices during the fourth quarter and, as such, no further write-down was recorded. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

Actual future prices and costs may be materially higher or lower than the prices and costs as of the end of the year of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the crude oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

The estimates of our reserves are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of crude oil and natural gas reserves, future net revenue from proved reserves and the PV-10 thereof for the crude oil and natural gas properties described in this report are based on the assumption that future crude oil and natural gas prices remain the same as crude oil and natural gas prices at December 31, 2002. The average sales prices as of such date used for purposes of such estimates were $29.69 per Bbl of crude oil, $18.89 per Bbl of NGLs and $3.79 per Mcf of natural gas. It is also assumed that we will make future capital expenditures of approximately $59.5 million in the aggregate, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

We file reports of our estimated crude oil and natural gas reserves with the Department of Energy and the Bureau of the Census. The reserves reported to these agencies are required to be reported on a gross operated basis and therefore are not comparable to the reserve data reported herein.

Crude Oil, Natural Gas Liquids, and Natural Gas Production and Sales Prices

The following table presents our net crude oil, net natural gas liquids and net natural gas production, the average sales price per Bbl of crude oil and natural gas liquids and per Mcf of natural gas produced and the average cost of production per BOE of production sold, for the three years ended December 31, 2002.

	2000	2001	2002

Crude oil production (Bbls).......	636,734	454,063	292,264
Natural gas production (Mcf)......	19,962,470	17,495,598	15,452,721
Natural gas liquids production (Bbls)......................	314,897	277,969	242,032
MMcfe............................	25,672	21,888	18,658
Average sales price per Bbl of crude oil....................	$ 18.69	$ 24.6	$ 24.34
Average sales price per MCF of natural gas (1)..............	$ 2.71	$ 3.20	$ 2.55
Average sales price per Bbl of natural gas liquids..........	$ 22.42	$ 21.51	$ 17.94
Average sales price per Mcfe......	$ 2.82	$ 3.35	$ 2.72
Average cost of production per Mcfe produced (2)............	$ 0.74	$ 0.85	$ 0.82

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(1) Average sales prices are net of hedging activity.
(2) Crude oil and natural gas were combined by converting crude oil and natural gas liquids to a Mcf equivalent ("Mcfe") on the basis of 1 Bbl of crude oil and natural gas liquid equals 6 Mcf of natural gas. Production costs include direct operating costs, ad valorem taxes and gross production taxes.

Drilling Activities

The following table sets forth our gross and net working interests in exploratory and development wells drilled during the three years ended December 31 2002.

	2000		2001	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Exploratory(3)				
Productive(4)				
Crude oil	-	-	-	-
Natural gas	3.0	2.5	2.0	1.0
Dry holes(5)	9.0	5.6	1.0	.5
Total	12.0	8.1	3.0	1.5
Development(6)				
Productive (4)				
Crude oil	9.0	9.0	2.0	2.0
Natural gas	16.0	12.2	13.0	11.0

Dry holes (5)	3.0	3.0	-	-
Total	28.0	24.2	15.0	13.0

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(1) A gross well is a well in which we own an interest.
(2) The number of net wells represents the total percentage of working interests held in all wells (e.g., total working interest of 50% is equivalent to 0.5 net well. A total working interest of 100% is equivalent to 1.0 net well).
(3) An exploratory well is a well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil or natural gas in another reservoir, or to extend a known reservoir.
(4) A productive well is an exploratory or a development well that is not a dry hole.
(5) A dry hole is an exploratory or development well found to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion as a crude oil or natural gas well.
(6) A development well is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved crude oil or natural gas reserves.

As of March 5, 2003, we had 6 wells in process of drilling and completing, 1 in the U.S. and 5 in Canada.

Office Facilities

Our executive and administrative offices are located at 500 North Loop 1604 East, Suite 100, San Antonio, Texas 78232. We also have an office in Midland, Texas. These offices, consisting of approximately 12,650 square feet in San Antonio and 570 square feet in Midland, are leased until March 2006 at an aggregate base rate of $19,500 per month.

New Grey Wolf leases 17,522 square feet of office space in Calgary, Alberta pursuant to a lease, which expires in April 2003.

Other Properties

We own 10 acres of land, an office building, workshop, warehouse and house in Sinton, Texas, 2.8 acres of land, an office building in Scurry County, Texas, 600 acres of fee land in Scurry County, Texas and 160 acres of land in Coke County, Texas. All three properties are used for the storage of tubulars and production equipment. We also own 19 vehicles which are used in the field by employees. We own 2 workover rigs, which are used for servicing our wells.

Item 3. Legal Proceedings

In 2001, Abraxas and Abraxas Wamsutter L.P. were named as defendants in a lawsuit filed in U.S. District Court in the District of Wyoming. The claim asserts breach of contract, fraud and negligent misrepresentation by Abraxas and Abraxas Wamsutter, L.P. related to the responsibility for year 2000 ad valorem taxes on crude oil and natural gas properties sold by Abraxas and Abraxas

Wamsutter, L.P. In February 2002, a summary judgment was granted to the plaintiff in this matter and a final judgment in the amount of $1.3 million was entered. Abraxas has filed an appeal. We believe these charges are without merit. We have established a reserve in the amount of $845,000, which represents our estimated share of the judgment.

In late 2000, Abraxas received a Final De Minimis Settlement Offer from the United States Environmental Protection Agency concerning the Casmalia Disposal Site, Santa Barbara County, California. Abraxas' liability for the cleanup at the Superfund site is based on a 1992 acquisition, which is alleged to have transported or arranged for the transportation of oil field waste and drilling muds to the Superfund site. Abraxas has engaged California counsel to evaluate the notice of proposed de minimis settlement and its notice of potential strict liability under the Comprehensive Environmental Response, Compensation and Liability Act. Defense of the action is handled through a joint group of crude oil companies, all of which are claiming a petroleum exclusion that limits Abraxas' liability. The potential financial exposure and any settlement posture has yet not been developed, but is considered by Abraxas to be immaterial.

Additionally, from time to time, we are involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2002, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our operations.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2002.

Item 4a. Executive Officers of Abraxas

Certain information is set forth below concerning our executive officers, each of whom has been selected to serve until the 2003 annual meeting of shareholders and until his successor is duly elected and qualified.

Robert L. G. Watson, age 52, has served as Chairman of the Board, President, Chief Executive Officer and a director of Abraxas since 1977. Since May 1996, Mr. Watson has also served as Chairman of the Board and a director of Grey Wolf. In November 1996, Mr. Watson was elected Chairman of the Board,

President and as a director of Canadian Abraxas. Prior to joining Abraxas, Mr. Watson was employed in various petroleum engineering positions with Tesoro Petroleum Corporation, a crude oil and natural gas exploration and production company, from 1972 through 1977, and DeGolyer and McNaughton, an independent petroleum engineering firm, from 1970 to 1972. Mr. Watson received a Bachelor of Science degree in Mechanical Engineering from Southern Methodist University in 1972 and a Master of Business Administration degree from the University of Texas at San Antonio in 1974.

Chris E. Williford, age 51, was elected Vice President, Treasurer and Chief Financial Officer of Abraxas in January 1993, and as Executive Vice President and a director of Abraxas in May 1993. In November 1996, Mr. Williford was elected Vice President and Assistant Secretary of Canadian Abraxas. In December 1999, Mr. Williford resigned as a director of Abraxas. Prior to joining Abraxas, Mr. Williford was Chief Financial Officer of American Natural Energy Corporation, a crude oil and natural gas exploration and production company, from July 1989 to December 1992 and President of Clark Resources Corp., a crude

oil and natural gas exploration and production company, from January 1987 to May 1989. Mr. Williford received a Bachelor of Science degree in Business Administration from Pittsburgh State University in 1973.

Robert W. Carington, Jr., age 41, was elected Executive Vice President and a director of the Company in July 1998. In December 1999, Mr. Carington resigned as a director of Abraxas. Prior to joining the Company, Mr. Carington was a Managing Director with Jefferies & Company, Inc. Prior to joining Jefferies & Company, Inc. in January 1993, Mr. Carington was a Vice President at Howard, Weil, Labouisse, Friedrichs, Inc. Prior to joining Howard, Weil, Labouisse, Friedrichs, Inc., Mr. Carington was a petroleum engineer with Unocal Corporation from 1983 to 1990. Mr. Carington received a degree of Bachelor of Science in Mechanical Engineering from Rice University in 1983 and a Masters of Business Administration from the University of Houston in 1990.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Market Information

Abraxas common stock began trading on the American Stock Exchange on August 18, 2000, under the symbol "ABP." The following table sets forth certain information as to the high and low bid quotations quoted for Abraxas' common stock on the American Stock Exchange.

	Period	High	Low
2001	First Quarter	$5.32	$3.69
	Second Quarter	4.98	3.10
	Third Quarter	3.65	1.70
	Fourth Quarter	1.85	0.88
2002			
	First Quarter	$1.70	$0.89
	Second Quarter	1.41	0.52
	Third Quarter	0.98	0.42
	Fourth Quarter	0.80	0.52
2003	First Quarter (Through March 5, 2003)	$0.99	$0.55

Holders

As of March 5, 2003, we had 35,622,096 shares of common stock outstanding and had approximately 1,606 stockholders of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, the indenture governing the New Notes and Senior Secured Credit Agreement prohibits the payment of cash dividends and stock dividends on our common stock. You should read the discussion under "Management's Discussion and

Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for more information regarding the restrictions on our ability to pay dividends.

Recent Sales of Unregistered Securities

On January 23, 2003, we issued approximately $109.7 million in principal amount of New Notes and 5,642,699 shares of Abraxas common stock in connection with the exchange offer. These securities were issued pursuant to the exemption from the registration requirements of the Securities Act of 1933, as amended, under Regulation D. The securities were offered and sold only to accredited investors and to no more than 35 non-accredited investors each of whom Abraxas believed had such knowledge and experience in financial and business matters that he or she was capable of evaluation of the merits and risks on the investment in the New Notes and shares of Abraxas common stock.

Securities Authorized for Issuance Under Equity Compensation Plans

Equity Compensation Plan Information

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 remaining future i equity com (excludi reflected
Equity compensation plan approved by security holders	3,003,340	$1.94	2,
Equity compensation plans not approved by security holders	1,252,000	$2.89	

Item 6. Selected Financial Data

The following selected financial data are derived from our Consolidated Financial Statements. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto, and other financial information included herein. See "Financial Statements" in Item 8.

	Year Ended December		
	1998	1999	2000
	(Dollars in thousands except per		

Total revenue (4)	$	60,084	$	66,770	$	76,600	$
Net income (loss) (4)	$	(83,960) (3)	$	(36,680) (3)	$	8,449 (2)	$
Net income (loss) per common share - diluted (4)	$	(13.26)	$	(5.41)	$	0.26	$
Weighted average shares outstanding - diluted (in thousands)		6,331		6,784		22,616	
Total assets	$	291,498	$	322,284	$	335,560	$
Long-term debt, excluding current maturities (4)	$	299,698	$	273,421	$	266,441	$
Total stockholders' equity (deficit)	$	(63,522)	$	(9,505)	$	(6,503)	$

(1) Includes ceiling limitation write-down of $116.0 million.

(2) Includes gain on sale of partnership interest of $34 million in 2000 and the reclassification of an extraordinary gain on debt extinguishment in 2000 to other income (see Note 20 to the consolidated financial statements).

(3) Includes ceiling limitation write-down of $61.2 million and $19.1 million for 1998 and 1999, respectively. (4) These amounts have been restated (see Note 20 to the consolidated financial statements). (5) Includes ceiling test write-down of $2.6 million in 2001, based on subsequent (March 22, 2002) realized prices, related to our Canadian operations.

Item 7. Management's Discussion And Analysis Of Financial Condition And Results Of Operations

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See "Financial Statements" in Item 8.

As discussed in Note 20 to the consolidated financial statements, the Company's financial statements have been restated. The accompanying management's discussion and analysis gives effect to that restatement.

General

We have incurred net losses in five of the last six years, and there can be no assurance that operating income and net earnings will be achieved in future periods. Our revenues, profitability and future rate of growth are substantially dependent upon prevailing prices for crude oil and natural gas and the volumes of crude oil, natural gas and natural gas liquids we produce. Crude oil and natural gas prices increased substantially in 2000. During 2001, crude oil and natural gas prices weakened substantially from the 2000 levels. During 2002, prices began to increase. In addition, because our proved reserves will decline as crude oil, natural gas and natural gas liquids are produced, unless we acquire additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Our ability to acquire or find additional reserves in the near future will be dependent, in part, upon the amount of available funds for acquisition, exploitation, exploration and development projects. In order to provide us with liquidity and capital resources, we have sold certain of our producing properties. However, our production levels have declined as we have been unable to replace the production represented by the properties we have sold with new

production from the producing properties we have invested in with the proceeds of our property sales. In addition, under the terms of our new senior secured credit agreement and our New Notes, we are subject to limitations on capital expenditures. As a result, we will be limited in our ability to replace existing production with new production and might suffer a decrease in the volume of crude oil and natural gas we produce. If crude oil and natural gas prices return to depressed levels or if our production levels continue to decrease, our revenues, cash flow from operations and financial condition will be materially adversely affected. For more information, see "Liquidity and Capital Resources - Current Liquidity Requirements" and "Future Capital Resources."

Results of Operations

General. Our financial results depend upon many factors, particularly the following factors which most significantly affect our results of operations:

- the sales prices of crude oil, natural gas liquids and natural gas;
- the level of total sales volumes of crude oil, natural gas liquids and natural gas;
- the ability to raise capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices. Our results of operations are significantly affected by fluctuations in commodity prices. Price volatility in the natural gas market has remained prevalent in the last few years. In the first quarter of 2002, we experienced a decline in energy commodity prices from the prices that we received in the first quarter of 2001. During the first quarter of 2001, we had certain crude oil and natural gas hedges in place that prevented us from realizing the full impact of a favorable price environment. In January 2001, the market price of natural gas was at its highest level in our operating history and the price of crude oil was also at a high level. However, over the course of 2001 and the beginning of the first quarter of 2002, prices again became depressed, primarily due to the economic downturn. Beginning in March 2002, commodity prices began to increase and continued higher through December 2002. Prices have continued to increase during the first part of 2003. As of March 5, 2003, the NYMEX price for natural gas was $7.02 per Mcf and $36.69 per Bbl for crude oil.

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The table below illustrates how natural gas prices fluctuated over the course of 2001 and 2002. The table below contains the last three day average of NYMEX traded contracts price and the prices we realized during each quarter for 2001 and 2002, including the impact of our hedging activities.

Natural Gas Prices by Quarter
(in $ per Mcf)

Quarter Ended						
March 31, 2001	June 30, 2001	Sept. 30, 2001	Dec. 31, 2001	March 31, 2002	June 30, 2002	Sept. 3 2002

Index	$7.27	$4.82	$2.98	$2.47	$2.38	$3.36	$3.28
Realized	4.85	3.41	2.26	2.09	2.21	2.44	2.08

The NYMEX natural gas price on March 5, 2003 was $7.02 per Mcf.

Prices for crude oil have followed a similar path as the commodity market fell throughout 2001 and the first quarter of 2002. The table below contains the last three day average of NYMEX traded contracts price and the prices we realized during each quarter for 2001 and 2002.

Crude Oil Prices by Quarter
(in $ per Bbl)

	Quarter Ended						
	March 31, 2001	June 30, 2001	Sept. 30, 2001	Dec. 31, 2001	March 31, 2002	June 30, 2002	Sept. 20
Index	$ 29.86	$ 27.94	$ 26.50	$ 22.12	$ 19.48	$ 26.40	$ 2
Realized	27.22	25.32	25.06	18.72	16.64	23.47	2

The NYMEX crude oil price on March 5, 2003 was $ 36.69 per Bbl.

Hedging Activities. We seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. In 2000, 2001 and 2002, we experienced hedging losses of $20.2 million, $12.1 million and $3.2 million, respectively. In October 2002, all of these hedge agreements expired. Under the expired hedge agreements, we made total payments over the term of these arrangements to various counterparties in the amount of $35.1 million.

Under the terms of our new senior secured credit agreement, we are required to maintain hedging positions with respect to not less than 25% nor more than 75% of our crude oil and natural gas production for a rolling six month period. On January 23, 2003, we entered into a collar option agreement with respect to 5,000 MMBtu per day, or approximately 25% of our production, at a call price of $6.25 per MMBtu and a put price of $4.00 per MMBtu agreement, for the calendar months of February through July 2003. In February 2003, we entered into a second hedge agreement for the calendar months of March 2003 through February 2004, related to 5,000 MMBtu which provides for a floor price of $4.50 per MMBtu.

Selected Operating Data. The following table sets forth certain of our operating data for the periods presented.

	Years Ended December 31,		
	(dollars in thousands, except per unit data)		
	2000	2001	2002

Operating revenue:*

Crude oil sales*...........................	$ 11,899	$ 11,184	$ 7,114
NGLs sales	7,061	5,979	4,343

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Natural gas sales*.........................	54,013	56,038	39,405
Gas processing revenue.....................	2,717	2,438	2,420
Rig and other..............................	910	1,604	1,038
Total operating revenues	$ 76,600	$ 77,243	$ 54,320
Operating income (loss)....................	$ 11,943	$ 19,125	$ (110,903)
Crude oil production (MBbls)...............	636.7	454.1	292.3
NGLs production (MBbls)....................	314.9	278.0	242.0
Natural gas production (MMcf)..............	19,962.5	17,495.6	15,452.7
Average crude oil sales price (per Bbl)*	$ 18.69	$ 24.63	$ 24.34
Average NGLs sales price (per Bbl)	$ 22.42	$ 21.51	$ 17.94
Average natural gas sales price (per Mcf)*	$ 2.71	$ 3.20	$ 2.55

*Revenue and average sales prices are net of hedging activities.

Comparison of Year Ended December 31, 2002 to Year Ended December 31, 2001:

Operating Revenue. During the year ended December 31, 2002, operating revenue from crude oil, natural gas and natural gas liquids sales decreased by $22.3 million from $73.2 million in 2001 to $50.9 million in 2002. This decrease was primarily attributable to a decrease in production volumes and lower commodity prices in 2002 as compared to 2001. Crude oil and natural gas revenue was impacted by $11.5 million from a decline in commodity prices and $10.8 million from reduced production. The decline in production was due to the disposition of certain properties in south Texas and natural field declines.

Natural gas liquids volumes declined from 278.0 MBbls in 2001 to 242.0 MBbls in 2002. Crude oil sales volumes declined from 454.1 MBbls in 2001 to 292.3 MBbls during 2002. Natural gas sales volumes decreased from 17.5 Bcf in 2001 to 15.5 Bcf in 2002. Production declines were primarily attributable to our disposition of assets during 2002 and natural field declines.

Average sales prices in 2002 net of hedging losses were:

- $ 24.34 per Bbl of crude oil,
- $ 17.94 per Bbl of natural gas liquids, and
- $ 2.55 per Mcf of natural gas.

Average sales prices in 2001 net of hedging losses were:

- $24.63 per Bbl of crude oil,
- $21.51 per Bbl of natural gas liquids, and
- $ 3.20 per Mcf of natural gas.

Lease Operating Expense. Lease operating expense ("LOE") decreased from $18.6 million in 2001 to $15.2 million in 2002. LOE on a per Mcfe basis for 2002 was $0.82 per Mcfe as compared to $0.83 per Mcfe in 2001. The decrease in the per Mcfe cost is due to a reduced operating cost offset by the decline in

production volumes.

G&A Expense. General and administrative ("G&A") expense increased slightly from $6.4 million in 2001 to $6.9 million in 2002. This increase was due primarily to increased legal expenses related to ongoing litigation in 2002. Our G&A expense on a per Mcfe basis increased from $0.30 in 2001 to $0.37 in 2002. The increase in the per Mcfe cost was due primarily to lower production volumes in 2002 as compared to 2001.

G&A - Stock-based Compensation Expense. Effective July 1, 2000, the Financial Accounting Standards Board ("FASB") issued FIN 44, "Accounting for Certain Transactions Involving Stock Compensation", an interpretation of

Accounting Principles Board Opinion No. ("APB") 25. Under the interpretation, certain modifications to fixed stock option awards which were made subsequent to December 15, 1998, and not exercised prior to July 1, 2000, require that the awards be subject to variable accounting until they are exercised, forfeited, or expired. In March 1999, we amended the exercise price to $2.06 on all options with an existing exercise price greater than $2.06. We charged approximately $2.8 million to stock-based compensation expense in 2000 compared to crediting approximately $2.8 million in 2001. This was due to the decline in the market price of our Common stock during 2001. During 2002, we did not recognize any stock-based compensation due to the decline in the price of our common stock.

DD&A Expense. Depreciation, depletion and amortization ("DD&A") expense decreased by $5.9 million from $32.4 million in 2001 to $26.5 million in 2002. The decline in DD&A is due to reductions in our full cost pool resulting from ceiling test write-downs, as well as lower production volumes. Our DD&A expense on a per Mcfe basis for 2002 was $1.42 per Mcfe as compared to $1.74 per Mcfe in 2001.

Interest Expense. Interest expense increased from $31.5 million to $34.1 million for 2002 compared to 2001. The increase was the result of additional sales pursuant to our production payment arrangement with Mirant Americas as well as increased borrowings under Old Grey Wolf's credit facility in 2002. The production payment was reacquired in June 2002 for approximately $6.8 million.

Ceiling Limitation Write-down. We record the carrying value of our crude oil and natural gas properties using the full cost method of accounting. For more information on the full cost method of accounting, you should read the description under "Critical Accounting Policies-- Full Cost Method of Accounting for Crude Oil and Natural Gas Activities". As of December 31, 2001, the Company's net capitalized costs of crude oil and natural gas properties exceeded the present value of its estimated proved reserves by $71.3 million. These amounts were calculated considering 2001 year-end prices of $19.84 per Bbl for crude oil and $2.57 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. The Company did not adjust its capitalized costs for its U.S. properties because subsequent to December 31, 2001, crude oil and natural gas prices increased such that capitalized costs for its U.S. properties did not exceed the present value of the estimated proved crude oil and natural gas reserves for its U.S. properties as determined using increased realized prices on March 22, 2002 of $24.16 per Bbl for crude oil and $2.89 per Mcf for natural gas.

At June 30, 2002, our net capitalized costs of crude oil and natural gas properties exceeded the present value of our estimated proved reserves by $138.7 million ($28.2 million on the U.S. properties and $110.5 million on the Canadian properties). These amounts were calculated considering June 30, 2002 prices of

$26.12 per Bbl for crude oil and $2.16 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. Subsequent to June 30, 2002, commodity prices increased in Canada and we utilized these increased prices in calculating the ceiling limitation write-down. The total write-down was approximately $116.0 million. At December 31, 2002 our net capitalized cost of crude oil and natural gas properties did not exceed the present value of our estimated reserves, due to increased commodity prices during the fourth quarter and, as such, no further write-down was recorded. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

The risk that we will be required to write-down the carrying value of our crude oil and natural gas assets increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves or if purchasers or governmental action cause an abrogation of, or if we voluntarily cancel, long-term contracts for our natural gas. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved resources are revised downward, a further write-down of the carrying value of our crude oil and natural gas properties may be required. See Note 18 of Notes to Consolidated Financial Statements.

Income taxes. Income tax expense decreased from an expense of $2.4 million for the year ended December 31, 2001 to a benefit of $29.7 million for the year ended December 31, 2002. The decrease was primarily due to the tax benefit relating to the ceiling limitation write-down related to our Canadian properties.

Comparison of Year Ended December 31, 2001 to Year Ended December 31, 2000:

Operating Revenue. During the year ended December 31, 2001, operating revenue from crude oil, natural gas and natural gas liquids sales, increased by $200,000 from $73.0 million in 2000 to $73.2 million in 2001. This increase was primarily attributable to an increase in commodity prices offset by a decline in production volumes. Increased prices contributed $12.9 million in additional revenue, which was offset by $12.7 million due to a decrease in production volumes. The decline in production was due to the disposition of certain properties and natural field declines.

Natural gas liquids volumes declined from 314.9 MBbls in 2000 to 278.0 MBbls in 2001. Crude oil sales volumes declined from 636.7 MBbls in 2000 to 454.1 MBbls during 2001. Natural gas sales volumes decreased from 20.0 Bcf in 2000 to 17.5 Bcf in 2001. Production declines were primarily attributable to our property disposition and natural field declines.

Average sales prices in 2001 net of hedging losses were:

- $ 24.63 per Bbl of crude oil,
- $ 21.51 per Bbl of natural gas liquids, and
- $ 3.20 per Mcf of natural gas.

Average sales prices in 2000 net of hedging losses were:

- $18.69 per Bbl of crude oil,
- $22.42 per Bbl of natural gas liquids, and
- $ 2.71 per Mcf of natural gas.

Lease Operating Expense. Lease operating expense decreased from $18.8 million in 2000 to $18.6 million in 2001. LOE on a per Mcfe basis for 2001 was $0.85 per Mcfe as compared to $0.73 per Mcfe in 2000. The increase in the per Mcfe cost is due to a decline in production volumes.

G&A Expense. General and administrative expense decreased from $6.5 million in 2000 to $6.4 million in 2001. Our G&A expense on a per Mcfe basis increased from $0.27 in 2000 to $0.29 in 2001. The increase in the per Mcfe cost was due primarily to lower production volumes in 2001 as compared to 2000.

G&A - Stock-based Compensation Expense. Effective July 1, 2000, the Financial Accounting Standards Board ("FASB") issued FIN 44, "Accounting for Certain Transactions Involving Stock Compensation", an interpretation of Accounting Principles Board Opinion No. ("APB") 25. Under the interpretation, certain modifications to fixed stock option awards which were made subsequent to December 15, 1998, and not exercised prior to July 1, 2000, require that the awards be subject to variable accounting until they are exercised, forfeited, or expired. In March 1999, we amended the exercise price to $2.06 on all options with an existing exercise price greater than $2.06. We charged approximately $2.8 million to stock-based compensation expense in 2000 compared to crediting approximately $2.8 million in 2001. This was due to the decline in the market price of our common stock during 2001.

DD&A Expense. Depreciation, depletion and amortization expense decreased by $3.4 million from $35.9 million in 2000 to $32.5 million in 2001. Our DD&A expense on a per Mcfe basis for 2001 was $1.48 per Mcfe as compared to $1.40 per Mcfe in 2000. The decline in DD&A is due to reductions in our full cost pool resulting from ceiling test write-downs in prior years, as well as lower production volumes.

Interest Expense. Interest expense increased by $400,000 from $31.1 million to $31.5 million for 2001 compared to 2000. This increase resulted from an increase in debt levels during 2001 compared to 2000. The increase in our debt level was the result of additional sales pursuant to our production payment arrangement with Mirant Americas.

Ceiling Limitation Write-down. We record the carrying value of our crude oil and natural gas properties using the full cost method of accounting for crude oil and natural gas properties. As of December 31, 2001, the Company's net capitalized costs of crude oil and natural gas properties exceeded the present value of its estimated proved reserves by $71.3, ($38.9 million on the U.S. properties and $32.4 million on the Canadian properties) million. These amounts were calculated considering 2001 year-end prices of $19.84 per Bbl for crude oil and $2.57 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. The Company did not adjust its capitalized costs for its U.S. properties because subsequent to December 31, 2001, crude oil and natural gas prices increased such that capitalized costs for its U.S. properties did not exceed the present value of the estimated proved crude oil and natural gas reserves for its U.S. properties as determined using increased realized prices on March 22, 2002 of $24.16 per Bbl for crude oil and $2.89 per Mcf for natural gas.

Income taxes. Income tax expense decreased from $3.7 million for the year ended December 31, 2000 to $2.4 million for the year ended December 31, 2001. Income taxes for the year ended December 31, 2000 related to deferred taxes on the sale of the Wamsutter partnership.

Other. In March 2000, Abraxas Wamsutter L.P. ("Partnership") sold all of its interest in its crude oil and natural gas properties to a third party. Prior

to the sale of these properties, effective January 1, 2000, the Company's equity investee share of crude oil and natural gas property cost, results of operations and amortization were not material to consolidated operations or financial position. As a result of the sale, the Company received approximately $34 million, which represented a proportional interest in the Partnership's proved properties.

In June 2000, we retired $3.5 million of the Old Notes and $3.6 million of the Second Lien Notes at a discount of $1.8 million.

Liquidity and Capital Resources

General. The crude oil and natural gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following costs:

- the development of existing properties, including drilling and completion costs of wells;
- acquisition of interests in crude oil and natural gas properties; and
- production and transportation facilities.

The amount of capital available to us will affect our ability to service our existing debt obligations and to continue to grow the business through the development of existing properties and the acquisition of new properties.

Our sources of capital are primarily cash on hand, cash from operating activities, funding under the new senior secured credit agreement and the sale of properties. Our overall liquidity depends heavily on the prevailing prices of crude oil and natural gas and our production volumes of crude oil and natural gas. Significant downturns in commodity prices, such as that experienced in the last nine months of 2001 and the first quarter of 2002, can reduce our cash from operating activities. Although we have hedged a portion of our natural gas and crude oil production and will continue this practice as required pursuant to the new senior secured credit agreement, future crude oil and natural gas price declines would have a material adverse effect on our overall results, and therefore, our liquidity. Low crude oil and natural gas prices could also negatively affect our ability to raise capital on terms favorable to us.

If the volume of crude oil and natural gas we produce decreases, our cash flow from operations will decrease. Our production volumes will decline as reserves are produced. In addition, due to sales of properties in 2002 and January 2003, we now have significantly reduced reserves and production levels. In the future we may sell additional properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration, exploitation and development activities, acquire additional producing properties or identify additional behind-pipe zones or secondary recovery reserves. While we have had some success in pursuing these

activities, historically, we have not been able to fully replace the production volumes lost from natural field declines and property sales.

Working Capital. At December 31, 2002 our current liabilities of approximately $82.8 million exceeded our current assets of $17.2 million. However, as a result of the financial restructuring completed in January 2003

our current liabilities were reduced by $75.7 million to $7.1 million as of January 23, 2003, which includes trade payables of $4.1 million and $1.6 million of revenues due third parties. After giving effect to the scheduled principal reductions required during 2003 under our senior secured credit agreement, we will have cash interest expense of approximately $4.0 million. We do not expect to make cash interest payments with respect to the outstanding New Notes, and the issuance of additional New Notes in lieu of cash interest payments thereon will not affect our working capital balance.

Capital Expenditures. Capital expenditures in 2000, 2001 and 2002 were $74.4 million, $57.1 million and $38.7 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2000, 2001 and 2002.

	Year Ended December 31,		
	2000	2001	2002
	(dollars in thousands)		
Expenditure category:			
Property acquisitions	$ 7,189	$ -	$ -
Development	64,873	56,694	38,560
Facilities and other	2,350	362	154
Total	$ 74,412	$ 57,056	$ 38,714

During 2000, 2001 and 2002, capital expenditures were primarily for the development of existing properties. For 2003, our capital expenditures are subject to limitations imposed under the new senior secured credit agreement and New Notes, including a maximum annual capital expenditure budget of $15 million for 2003, and subject to reduction in the event of a reduction in our net assets. We currently expect to have a capital expenditure budget of up to $8 million for the first quarter of 2003. Our capital expenditures could include expenditures for acquisition of producing properties if such opportunities arise, but we currently have no agreements, arrangements or undertakings regarding any material acquisitions. We have no material long-term capital commitments and are consequently able to adjust the level of our expenditures as circumstances dictate. Additionally, the level of capital expenditures will vary during future periods depending on market conditions and other related economic factors. Should the prices of crude oil and natural gas decline from current levels, our cash flows will decrease which may result in a reduction of the capital expenditures budget. If we decrease our capital expenditures budget, we may not be able to offset crude oil and natural gas production volumes decreases caused by natural field declines and sales of producing properties.

Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	2000	2001	
		(dollars in thousands)	
Net cash (used in) provided by operating activities	$ 21,372	$ 16,263	$

Net cash used in investing activities	(18,773)	(30,797)	
Net cash provided by (used in) financing activities	(3,818)	20,685	
Total	$ (1,219)	$ 6,151	$

Operating activities for the year ended December 31, 2002, used $8.4 million of cash. Investing activities used $5.0 million during 2002. Our investing activities included the sale of properties which provided $33.9 million, and the use of $38.7 million primarily for the development of producing

properties. Financing activities provided us with $10.8 million during 2002, relating primarily to advances on Old Grey Wolf's credit facility.

Operating activities for the year ended December 31, 2001 provided us $16.3 million of cash. Investing activities included the sale of properties which provided $28.9 million, and the use of $57.1 million for the development of producing properties and $2.7 million for the acquisition of the minority interest in Grey Wolf. Financing activities provided $20.7 million during 2001, including the provision of additional funding of $11.7 million under our production payment arrangement with Mirant Americas, and the provision of $18.3 million under Old Grey Wolf's credit facility. Payments on long-term debt used $9.3 million.

Future Capital Resources. We will have four principal sources of liquidity going forward: (i) cash on hand, (ii) cash from operating activities, (iii) funding under the revolving credit facility, and (iv) sales of producing properties. However, covenants under the indenture for the outstanding New Notes and the new senior secured credit agreement restrict our use of cash on hand, cash from operating activities and any proceeds from asset sales. We may attempt to raise additional capital through the issuance of additional debt or equity securities, though the terms of the new note indenture and the new senior secured credit agreement substantially restrict our ability to:

- incur additional indebtedness;
- incur liens;
- pay dividends or make certain other restricted payments;
- consummate certain asset sales;
- enter into certain transactions with affiliates;
- merge or consolidate with any other person; or
- sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of our assets.

Our best opportunity for additional sources of liquidity and capital will be through the issuance of equity securities or through the disposition of assets, as allowed under the various financing arrangements.

Contractual Obligations

We are committed to making cash payments in the future on the following types of agreements:

- o Long-term debt
- o Operating leases for office facilities

We have no off-balance sheet debt or unrecorded obligations and we have not guaranteed the debt of any other party. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2002.

Contractual Obligations (dollars in thousands)	Payments due in:				
	Total	2003	2004	2005	2006
Long-Term Debt (1)	$300,443	$ 63,500	$ 190,979	$ -	$ -
Operating Leases (2)	985	336	236	236	177

(1) After the transactions described in Item 1 - "Recent Events," the amounts would be $0 in each of the three years 2003, 2004 and 2005, $47,996 in 2006 and $184,000 for 2007. These amounts represent the balances outstanding under the term loan facility, the revolving credit facility and the New Notes. These repayments assume that interest will be capitalized under the term loan facility and that periodic interest on the new senior secured credit agreement will be paid on a monthly basis and that we will not draw down additional funds there under.

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(2) Office lease obligations. Leases for office space for Abraxas and New Grey Wolf expire in April 2006 and April 2003, respectively.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude oil and natural gas. In the past, we have funded our operations and capital expenditures primarily through cash flow from operations, sales of properties, sales of production payments and borrowings under our bank credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

Long-Term Indebtedness. The recently completed financial restructuring resulted in the retirement of our first lien notes, second lien notes and old notes, together with the Old Grey Wolf credit facility. As of March 5, 2003, our long-term indebtedness consists of the senior credit facility and the notes issued in connection with the financial restructuring. The following table sets forth our long-term indebtedness as of December 31, 2002, and proforma information reflecting the consummation of the restructuring transactions.

Long Term Indebtedness

	December 31	
	2001	2
	(In thousan	
12 7/8% Senior Secured Notes due 2003 (first lien notes)..............	$ 63,500	$
11 1/2% Senior Secured Notes due 2004 (second lien notes).............	190,178	1
11 1/2% Senior Notes due 2004 (old lien notes)........................	801	
9 1/2% Senior Credit Facility ("Grey Wolf Facility") providing for borrowings up to approximately US $96 million (CDN $150 million). Secured by the assets of Old Grey Wolf and non-recourse to Abraxas....................................	22,944	
Production Payment	8,176	
11 1/2% Secured Notes due 2007 (New Notes) - January 2003..........	-	
New Senior Secured Credit Agreement - January 2003.................	-	
	285,599	3
Less current maturities	415	
	$ 285,184	$ 2

(a) After the transactions described in Note 2, for financial reporting purposes, the New Notes will be reflected at the carrying value of the Second Lien Notes and Old Notes prior to the exchange of $191.0 million, net of the cash offered in the exchange of $47.5 million and net of the fair market value related to equity of $3.8 million offered in the exchange. In conjunction with the financial restructuring transaction, Abraxas paid cash of $11.5 million ($11.1 in principal and $0.4 million in interest) to redeem certain of the outstanding old debt and accrued interest. The result of all of these items will be a remaining carrying value of the New Notes of $128.6 million. The face amount of the New Notes is $109.7 million. See Note 2 of Notes to Consolidated Financial Statements in Item 8 for terms and conditions of the New Notes and the New Senior Secured Credit Agreement.

New Notes - 11 1/2% Secured Notes. In connection with the financial restructuring, Abraxas issued $109.7 million in principal amount of it's 11 1/2% Secured Notes due 2007, Series A, in exchange for the second lien notes and old notes tendered in the exchange offer. The New Notes were issued under an indenture with U.S. Bank, N. A.

The New Notes accrue interest from the date of issuance, at a fixed annual rate of 11 1/2%, payable in cash semi-annually on each May 1 and November 1, commencing May 1, 2003, provided that, if we fail, or are not permitted pursuant to our new senior secured credit agreement or the intercreditor agreement between the trustee under the indenture for the New Notes and the lenders under the new senior secured credit agreement, to make such cash interest payments in full, we will pay such unpaid interest in kind by the issuance of additional New Notes with a principal amount equal to the amount of accrued and unpaid cash

interest on the New Notes plus an additional 1% accrued interest for the applicable period. Upon an event of default, the New Notes accrue interest at an annual rate of 16.5%.

The New Notes are secured by a second lien or charge on all of our current and future assets, including, but not limited to, all of our crude oil and natural gas properties. All of Abraxas' current subsidiaries, Sandia Oil & Gas, Sandia Operating (a wholly-owned subsidiary of Sandia Oil & Gas), Wamsutter, New Grey Wolf, Western Associated Energy and Eastside Coal, are guarantors of the New Notes, and all of Abraxas' future subsidiaries will guarantee the New Notes. If Abraxas cannot make payments on the New Notes when they are due, the guarantors must make them instead.

The New Notes and related guarantees

- are subordinated to the indebtedness under the new senior secured credit agreement;
- rank equally with all of Abraxas' current and future senior indebtedness; and
- rank senior to all of Abraxas' current and future subordinated indebtedness, in each case, if any.

The New Notes are subordinated to amounts outstanding under the new senior secured credit agreement both in right of payment and with respect to lien priority and are subject to an intercreditor agreement.

Abraxas may redeem the New Notes, at its option, in whole at any time or in part from time to time, at redemption prices expressed as percentages of the principal amount set forth below. If Abraxas redeems all or any New Notes, it must also pay all interest accrued and unpaid to the applicable redemption date. The redemption prices for the New Notes during the indicated time periods are as follows:

Period	Percentage
From January 24, 2003 to June 23, 2003	80.0429%
From June 24, 2003 to January 23, 2004	91.4592%
From January 24, 2004 to June 23, 2004	97.1674%
From June 24, 2004 to January 23, 2005	98.5837%
Thereafter	100.0000%

Under the indenture, we are subject to customary covenants which, among other things, restrict our ability to:

- borrow money or issue preferred stock;
- pay dividends on stock or purchase stock;
- make other asset transfers;
- transact business with affiliates;
- sell stock of subsidiaries;
- engage in any new line of business;
- impair the security interest in any collateral for the notes;

- use assets as security in other transactions; and

- sell certain assets or merge with or into other companies.

In addition, we are subject to certain financial covenants including covenants limiting our selling, general and administrative expenses and capital expenditures, a covenant requiring Abraxas to maintain a specified ratio of consolidated EBITDA, as defined in the agreements, to cash interest and a covenant requiring Abraxas to permanently, to the extent permitted, pay down debt under the new senior secured credit agreement and, to the extent permitted by the new senior secured credit agreement, the New Notes or, if not permitted, paying indebtedness under the new senior secured credit agreement.

The indenture contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

New Senior Secured Credit Agreement. In connection with the financial restructuring, Abraxas entered into a new senior secured credit agreement providing a term loan facility and a revolving credit facility as described below. Subject to earlier termination on the occurrence of events of default or other events, the stated maturity date for both the term loan facility and the revolving credit facility is January 22, 2006. In the event of an early termination, we will be required to pay a prepayment premium, except in the limited circumstances described in the new senior secured credit agreement. Outstanding amounts under both facilities bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 4.5%. Any amounts in default under the term loan facility will accrue interest at an additional 4%. At no time will the amounts outstanding under the new senior secured credit agreement bear interest at a rate less than 9%.

Term Loan Facility. Abraxas has borrowed $4.2 million pursuant to a term loan facility at January 23, 2003, all of which was used to make cash payments in connection with the financial restructuring. Accrued interest under the term loan facility will be capitalized and added to the principal amount of the term loan facility until maturity.

Revolving Credit Facility. Lenders under the new senior secured credit agreement have provided a revolving credit facility to Abraxas with a maximum borrowing base of up to $50 million. Our current borrowing base under the revolving credit facility is $49.9 million, subject to adjustments based on periodic calculations and mandatory prepayments under the senior secured credit agreement. Portions of accrued interest under the revolving credit facility may be capitalized and added to the principal amount of the revolving credit facility. At January 23, 2003, we have borrowed $42.5 million under the revolving credit facility, all of which was used to make cash payments in connection with the financial restructuring. We plan to use the remaining borrowing availability under the new senior secured credit agreement to fund our operations, including capital expenditures.

Covenants. Under the new senior secured credit agreement, Abraxas is subject to customary covenants and reporting requirements. Certain financial covenants require Abraxas to maintain minimum levels of consolidated EBITDA (as defined in the new senior secured credit agreement), minimum ratios of consolidated EBITDA to cash interest expense and a limitation on annual capital expenditures. In addition, at the end of each fiscal quarter, if the aggregate amount of our cash and cash equivalents exceeds $2.0 million, we are required to

repay the loans under the new senior secured credit agreement in an amount equal to such excess. The new senior secured credit agreement also requires us to enter into hedging agreements on not less than 25% or more than 75% of our projected oil and gas production. We are also required to establish deposit accounts at financial institutions acceptable to the lenders and we are required to direct our customers to make all payments into these accounts. The amounts in these accounts will be transferred to the lenders upon the occurrence and during the continuance of an event of default under the new senior secured credit agreement.

In addition to the foregoing and other customary covenants, the new senior secured credit agreement contains a number of covenants that, among other things, restrict our ability to:

- incur additional indebtedness;
- create or permit to be created any liens on any of our properties;
- enter into any change of control transactions;

- dispose of our assets;
- change our name or the nature of our business;
- make any guarantees with respect to the obligations of third parties;
- enter into any forward sales contracts;
- make any payments in connection with distributions, dividends or redemptions relating to our outstanding securities, or
- make investments or incur liabilities.

Guarantees. The obligations of Abraxas under the new senior secured credit agreement are guaranteed by Sandia Oil & Gas, Sandia Operating, Wamsutter, New Grey Wolf, Western Associated Energy and Eastside Coal. Obligations under the new senior secured credit agreement are secured by a first lien security interest in substantially all of Abraxas' and the guarantors' assets, including all crude oil and natural gas properties.

Events of Default. The new senior credit facility contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. Under the new senior secured credit agreement, we are required maintain hedge positions on not less than 25% or more than 75% of our projected oil and gas production for a six month rolling period. On January 23, 2003, we entered into a collar option agreement with respect to 5,000 MMBtu per day, or approximately 25% of our production, at a call price of $6.25 per MMBtu and a put price of $4.00 per MMBtu, for the calendar months of February through July 2003. In February 2003, we entered into a second hedge agreement related to

5,000 MMBtu for the calendar months of March 2003 through February 2004 which provides for a floor price of $4.50 per MMBtu. See "Item 7A--Quantitative and Qualitative Disclosures about Market Risk--Hedging Sensitivity" for further information.

Net Operating Loss Carryforwards

At December 31, 2002, the Company had, subject to the limitation discussed below, $166.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2003 through 2022 if not utilized. At December 31, 2002, the Company had approximately $1.0 million of net operating loss carryforwards for Canadian tax purposes. These carryforwards will expire from 2003 through 2009 if not utilized. In connection with January 2003 transactions described in Note 2, in Notes to Consolidated Financial Statements, Item 8, certain of the loss carryforwards may be utilized.

As a result of the acquisition of certain partnership interests and crude oil and natural gas properties in 1990 and 1991, an ownership change under Section 382 occurred in December 1991. Accordingly, it is expected that the use of the U.S. net operating loss carryforwards generated prior to December 31, 1991 of $3,203,000 will be limited to approximately $235,000 per year.

During 1992, the Company acquired 100% of the common stock of an unrelated corporation. The use of net operating loss carryforwards of the acquired corporation of $257,000 acquired in the acquisition are limited to approximately $115,000 per year.

As a result of the issuance of additional shares of common stock for acquisitions and sales of common stock, an additional ownership change under Section 382 occurred in October 1993. Accordingly, it is expected that the use of all U.S. net operating loss carryforwards generated through October 1993 (including those subject to the 1991 and 1992 ownership changes discussed above) of $6,590,000 will be limited as described above and in the following paragraph.

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An ownership change under Section 382 occurred in December 1999, following the issuance of additional shares, as described in Note 6. It is expected that the annual use of U.S. net operating loss carryforwards subject to this Section 382 limitation will be limited to approximately $363,000, subject to the lower limitations described above. Future changes in ownership may further limit the use of the Company's carryforwards. In 2000 assets with built-in gains were sold, increasing the Section 382 limitation for 2001 by approximately $31,000,000.

The annual Section 382 limitation may be increased during any year, within 5 years of a change in ownership, in which built-in gains that existed on the date of the change in ownership are recognized.

In addition to the Section 382 limitations, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, the Company has established a valuation allowance of $39.7 million and $99.1 million for deferred tax assets at December 31, 2001 and 2002, respectively.

Related Party Transactions

Accounts receivable - Other in the consolidated balances sheets includes approximately $48,365 and $51,211 as of December 31, 2001 and 2002, respectively, representing amounts due from officers and stockholders relating to advances made to employees.

Wind River Resources Corporation ("Wind River"), all of the capital stock of which is owned by the Company's President, owns a twin-engine airplane. The airplane is available for business use by the employees of the Company from time to time. The Company paid Wind River a total of approximately $336,000, $314,000 and $345,000 in 2000, 2001 and 2002 respectively, for Wind River's operating costs associated with the Company's use of the plane.

Critical Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Full Cost Method of Accounting for Crude Oil and Natural Gas Activities. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in crude oil and natural gas activities. Two methods are prescribed: the successful efforts method and the full cost method. Abraxas has chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of crude oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of crude oil and natural gas properties under the successful efforts method. As a result our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization date on our crude oil and natural gas properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not

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recoverable when prices return to higher levels. The Company has experienced this situation several times over the years, most recently in 2002. Our crude oil and natural gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including

impact from the full cost method of accounting.

Under full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a "ceiling limit" which is 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 exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for our natural gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher crude oil and natural gas prices may have increased the ceiling applicable to the subsequent period.

For the year ended December 31, 2002, we recorded a write-down of $116.0 million. The write-down in 2002 was due to low commodity prices. We cannot assure you that we will not experience additional write-downs in the future. Should commodity prices decline, a further write-down of the carrying value of our crude oil and natural gas properties may be required.

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions;
- and the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this Report was based on evaluations prepared by independent petroleum engineers. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, the Company based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which the Company records DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Hedge Accounting. From time to time, we use commodity price hedges to limit our exposure to fluctuations in crude oil and natural gas prices. Results of

those hedging transactions are reflected in crude oil and natural gas sales.

Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," was effective for the Company on January 1, 2001. SFAS 133, as amended and interpreted, establishes

accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Under this statement, all derivatives, whether designated in hedging relationships or not, are required to be recorded at fair value on our balance sheet. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. For derivative instruments designated as fair value hedges, changes in fair value, to the extent the hedge is effective, are recognized as an increase or decrease to the value of the hedged item until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow or fair value hedge are also recognized in earnings through risk management income. All amounts initially recorded in this caption are ultimately reversed within the same caption and included in oil and gas sales or interest expense, as applicable, over the respective contract terms.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated because energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of crude oil and natural gas prices and, to a lesser extent, interest rates, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2001 the net market value of our derivatives was a liability of $658,000. As of December 31, 2002 we did not have any outstanding

derivatives.

New Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS No. 141 and 142 clarify that more assets should be distinguished and classified between tangible and intangible. The Company did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. The Company believes the treatment of such mineral rights as tangible assets under the full cost method of accounting for crude oil and natural gas properties is appropriate. An issue has arisen regarding whether contractual mineral rights should be classified as intangible rather that tangible assets. If it is determined that reclassification is necessary, the Company's oil and gas properties would be reduced by $868,000 million and $3.1 and intangible assets would have increased by a like amount at December 31, 2001 and 2002, respectively, representing cost incurred from the effective date of June 30, 2001. The provisions of SFAS No. 141 and 142 impact only the balance sheet and associated footnote disclosure, and reclassifications necessary would not impact the Company's cash flows or results of operations.

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In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 is effective for us January 1, 2003. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense.

We have completed our assessment of SFAS No. 143 and based on our estimates, we do not expect the statement to have a material effect on our financial position, results of operations and cash flows for future periods. At January 1, 2003, we estimate that the present value of our future Asset Retirement Obligation ("ARO") for natural gas and oil property and related equipment is approximately $657,000. We estimate that the cumulative effect to the adoption of SFAS No. 143 and the change in the accounting principle will be a loss of $285,000, which will be recorded in the first quarter of 2003. The impact on each of the prior years was not material.

Effective January 1, 2002, we adopted SFAS No. 144 " Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 retains the

requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS No. 144, among other things, changes the criteria that have to be met to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. This new standard had no impact on the consolidated financial statements for the year ended December 31, 2002.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB No. 4, 44, and 64, Amendments of FASB Statement No. 13 and Technical Corrections." SFAS No. 145 clarifies guidance related to the reporting of gains and losses from extinguishment of debt and resolves inconsistencies related to the required accounting treatment of certain lease modifications. SFAS No. 145 also amends other existing pronouncements to make various technical corrections, clarify meanings or describe their applicability under changed conditions. The provisions relating to the reporting of gains and losses from extinguishment of debt become effective for us beginning January 1, 2003. All other provisions of this standard were effective for us as of May 15, 2002 and did not have an impact on our financial condition or results of operations. Upon issuance of our restated financial statements included in this Form 10-K/A we have reclassified the gain on the early extinguishment of debt in 2000 from an extraordinary item to other income - see Note 20. This reclassification did not affect net income for the year ended December 31, 2000.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 requires costs associated with exit of disposal activities to be recognized when they are incurred rather than at the date of commitment to an exit or disposal plan. SFAS No. 146 is effective for us beginning January 1, 2003. We are currently evaluating the impact the standard will have on our results of operations and financial condition.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-based Compensation--Transition and Disclosure, an amendment of FASB Statement No. 123," which amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions of SFAS No. 123 to require prominent disclosure 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. The provisions of SFAS No. 148 are effective for annual financial statements for fiscal years ending after December 15, 2002, and for financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. The Company will continue to use APB No. 25 to account for stock based compensation while providing the disclosures required by SFAS No. 123 as amended by SFAS No. 148.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent crude oil and natural gas producer, our revenue, cash flow from operations, other income and equity earnings and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of crude oil, natural gas and natural gas liquids. Declines in commodity prices will materially adversely affect our financial condition, liquidity, ability to obtain financing and operating

results. Lower commodity prices may reduce the amount of crude oil and natural gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global political and economic conditions. Historically, prices received for crude oil and natural gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2002, a 10% decline in crude oil, natural gas and natural gas liquids prices would have reduced our operating revenue, cash flow and net income by approximately $5.1 million for the year.

Hedging Sensitivity

On January 1, 2001, we adopted SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138. Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we use only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in Other Comprehensive Income/Loss, a component of Stockholders' Equity, to the extent that the hedge is effective.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in accumulated Other Comprehensive Income/Loss related to a cash flow hedge that becomes ineffective, remain unchanged until the related production is delivered. If we determine that it is probable that a hedged transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Gains and losses on hedging instruments related to accumulated Other Comprehensive Income and adjustments to carrying amounts on hedged production are included in natural gas or crude oil production revenue in the period that the related production is delivered.

In 2000, 2001 and 2002, we experienced hedging losses of $20.2 million, $12.1 million and $3.2 million, respectively. In October 2002, all of these hedge agreements expired. Under the expired hedge agreements, we made total payments to various counterparties in the amount of $35.1 million.

Under the terms of the new senior secured credit agreement, we are required to maintain hedging positions with respect to not less than 25% nor more than 75% of our crude oil and natural gas production for a rolling six month period. As of January 23, 2003, we have entered into a collar option agreement with respect to 5,000 MMBtu per day, or approximately 25% of our production, at a call price of $6.25 per MMBtu and a put price of $4.00 per MMBtu. In February of 2003 we entered into an additional hedge agreement for 5,000 MMBtu per day with a floor of $4.50 per MMBtu. As of March 5, 2003, the fair market value of our

hedge positions is not material. For Abraxas, the fair value of the hedging instrument was determined based on the base price of the hedged item and NYMEX forward price quotes.

The following table sets forth our hedging position as of March 5, 2003.

Time Period	Notional Quantities	Price
February 1, 2003--July 31, 2003	5,000 MMBtu of production per day	Collar with floor of $4. and ceiling of $6.25
March 1, 2003 - February 29, 2004	5,000 MMBtu of production per day	Floor of $4.50

All hedge transactions are subject to our risk management policy, which has been approved by the Board of Directors. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Interest rate risk

At December 31, 2002, substantially all of Abraxas' long-term debt was at fixed interest rates from 11.5% to 12.875% and not subject to fluctuations in market rates and Old Grey Wolf's long-term debt was at a fixed interest rate of 9.5%.

As a result of the financial restructuring that occurred in January 2003, we will have approximately $46.7 million in outstanding indebtedness under the new senior secured credit agreement, accruing interest at a rate of prime plus 4.5%, subject to a minimum interest rate of 9.0%. In the event that the prime rate (currently 1.5%) rises above 4.5% the interest rate applicable to our outstanding indebtedness under the new senior secured credit agreement will rise accordingly. For every percentage point that the prime rate rises above 4.5%, our interest expense would increase by approximately $467,000 on an annual basis. Our New Notes accrue interest at fixed rates and is accordingly not subject to fluctuations in market rates.

Foreign Currency

Our Canadian operations are measured in the local currency of Canada. As a result, our financial results are affected by changes in foreign currency exchange rates or weak economic conditions in the foreign markets. Canadian operations reported a pre-tax loss of $63.4 million for the year ended December 31, 2002. It is estimated that a 5% change in the value of the U.S. dollar to the Canadian dollar would have changed our net loss by approximately $3.2 million. We do not maintain any derivative instruments to mitigate the exposure to translation risk. However, this does not preclude the adoption of specific hedging strategies in the future.

Item 8. Financial Statements

For the financial statements and supplementary data required by this Item 8, see the Index to Consolidated Financial Statements.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

PART III

Item 10. Directors and Executive Officers of the Registrant

There is incorporated in this Item 10 by reference that portion of our definitive proxy statement for the 2003 Annual Meeting of Stockholders which appears therein under the caption "Election of Directors". See also the information in Item 4a of Part I of this Report.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2003 Annual Meeting of Stockholders which appears therein under the caption "Executive Compensation", except for those parts under the captions "Compensation Committee Report on Executive Compensation," "Performance Graph", "Audit Committee Report" and "Report on Repricing of Options."

Item 12. Security Ownership of Certain Beneficial Owners and Management

There is incorporated in this Item 12 by reference that portion of our definitive proxy statement for the 2003 Annual Meeting of Stockholders which appears therein under the caption "Securities Holdings of Principal Stockholders, Directors and Officers."

Item 13. Certain Relationships and Related Transactions

There is incorporated in this Item 13 by reference that portion of our definitive proxy statement for the 2003 Annual Meeting of Stockholders which appears therein under the caption "Certain Transactions."

Item 14. Controls and Procedures

Within the 90 days prior to the filing date of this report, we carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-14 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required to be included in our periodic filings under the Exchange Act. Subsequent to the date of this evaluation, there have been no significant changes in our internal controls or in other factors that could significantly affect internal controls, nor were any corrective actions required with regard to significant deficiencies or material weaknesses.

Subsequent to the issuance of our consolidated financial statements for the year ended December 31, 2002, our management determined that the wholly owned Canadian subsidiaries should not have been presented as discontinued operations. As a result, the accompanying consolidated balance sheets as of December 31, 2002 and 2001, and the related consolidated statements of operations, and cash flows for each of the three years in the period ended December 31, 2002 have been restated to present the assets and liabilities, results of operations, and cash flows as components of continuing operations. This restatement relates to the inappropriate initial implementation of SFAS No. 144. In the future, we will monitor all new standards to determine the appropriate approach of implementation given our industry's method of accounting.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

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(a)2. Financial Statement Schedules

All schedules have been omitted because they are not applicable, not required under the instructions or the information requested is set forth in the consolidated financial statements or related notes thereto.

(a)3.Exhibits

The following Exhibits have previously been filed by the Registrant or are included following the Index to Exhibits.

Exhibit Number.	Description
3.1	Articles of Incorporation of Abraxas. (Filed as Exhibit 3.1 to Abraxas' Registration Statement on Form S-4, No. 33-36565 (the "S-4 Registration Statement")).
3.2	Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement).
3.3	Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement).

3.4	Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to Abraxas' Registration Statement on Form S-3, No. 333-00398 (the "S-3 Registration Statement")).
3.5	Articles of Amendment to the Articles of Incorporation of Abraxas dated as of August 12, 2000 (Filed as Exhibit 3.5 to Abraxas' Annual Report of Form 10-K filed April 2, 2001).
3.6	Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.6 to Abraxas' Annual Report on Form 10-K filed April 5, 2002).
4.1	Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).
4.2	Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to Abraxas' Annual Report on Form 10-K filed on March 31, 1995).
4.3	Rights Agreement dated as of December 6, 1994 between Abraxas and First Union National Bank of North Carolina ("FUNB"). (Filed as Exhibit 4.1 to Abraxas' Registration Statement on Form 8-A filed on December 6, 1994).
4.4	Amendment to Rights Agreement dated as of July 14, 1997 by and between Abraxas and American Stock Transfer & Trust Company. (Filed as Exhibit 1 to Amendment No. 1 to Abraxas' Registration Statement on Form 8-A filed on August 20, 1997).
4.5	Second Amendment to Rights Agreement as of May 22, 1998, by and between Abraxas and American Stock Transfer & Trust Company. (Filed as Exhibit 1

to Amendment No. 2 to Abraxas' Registration Statement on Form 8-A filed on August 24, 1998).

4.6 Indenture dated January 23, 2003, by and among Abraxas, as Issuer; the subsidiary Guarantors party thereto and U.S. Bank, N.A., as Trustee, relating to Abraxas' 11-1/2 % Secured Notes Due 2007. (filed as Exhibit 4.1 to Abraxas' Current Report on Form 8-K dated February 6, 2003).

4.7 Form of 111/2% Secured Notes due 2007. (Filed as Exhibit A to Exhibit 4.6).

*10.1 Abraxas Petroleum Corporation 1984 Non-Qualified Stock Option Plan, as amended and restated. (Filed as Exhibit 10.7 to Abraxas' Annual Report on Form 10-K filed April 14, 1993).

*10.2 Abraxas Petroleum Corporation 1984 Incentive Stock Option Plan, as amended and restated. (Filed as Exhibit 10.8 to Abraxas' Annual Report on Form 10-K filed April 14, 1993).

*10.3 Abraxas Petroleum Corporation 1993 Key Contributor Stock Option Plan. (Filed as Exhibit 10.9 to Abraxas' Annual Report on Form 10-K filed April 14, 1993).

*10.4 Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to Abraxas' Registration Statement on Form S-4, No. 333-18673, (the "1996 Exchange Offer Registration Statement")).

*10.5 Abraxas Petroleum Corporation Director Stock Option Plan. (Filed as Exhibit 10.5 to the 1996 Exchange Offer Registration Statement).

*10.6 Abraxas Petroleum Corporation Restricted Share Plan for Directors. (Filed as Exhibit 10.20 to Abraxas' Annual Report on Form 10-K filed on April 12, 1994).

*10.7 Abraxas Petroleum Corporation 1994 Long Term Incentive Plan. (Filed as Exhibit 10.21 to Abraxas' Annual Report on Form 10-K filed on April 12, 1994).

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*10.8 Abraxas Petroleum Corporation Incentive Performance Bonus Plan. (Filed as Exhibit 10.24 to Abraxas' Annual Report on Form 10-K filed on April 12, 1994).

10.9 Common Stock Purchase Warrant dated August 11, 1993 between Abraxas and Associated Energy Managers, Inc. (Filed as Exhibit 10.37 to Abraxas' Registration statement on Form S-1, Registration No. 33-66446, (the "1993 S-1 Registration Statement")).

10.10 Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.30 to the 1993 S-1.

10.16 Common Stock Purchase Warrant dated September 1, 2000 between Jessup & Lamont Holdings (Filed as Exhibit 10.16 to Abraxas Annual Report on Form 10-K filed on April 2, 2001).

10.17 Common Stock Purchase Warrant dated August 1, 2000 between Abraxas and TNC, Inc. (Filed as Exhibit 10.17 to Abraxas Annual Report on Form 10-K

filed on April 2, 2001).

10.18 Common Stock Purchase Warrant dated August 1, 2000 between Abraxas and Charles K. Butler (Filed as Exhibit 10.17 to Abraxas Annual Report on Form 10-K filed on April 2, 2001).

10.19 Agreement of Limited Partnership of Abraxas Wamsutter L.P. dated as of November 12, 1999 by and between Wamsutter Holdings, Inc. and TIFD III-X Inc. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed November 30,1999).

10.20 Purchase Agreement for Dollar Denominated Production Payment dated as of October 6, 1999 by and between Abraxas and Southern Producer Services, L.P. (Filed as Exhibit 10.1 to Abraxas' Quarterly Report on Form 10-Q filed November 15, 1999).

10.21 Conveyance of Dollar Denominated Production Payment dated as of October 6, 1999 by and between Abraxas and Southern Producer Services, L.P. (Filed as Exhibit 10.2 to Abraxas' Quarterly Report on Form 10-Q filed November 15, 1999).

10.22 Purchase and Sale Agreement dated November 21, 2002, by and among Abraxas, as Seller, Primewest Gas Inc., as Purchaser, Primewest Energy Inc., as Guarantor, Canadian Abraxas and Grey Wolf Exploration Inc., as the Companies (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K/A filed December 9, 2002).

10.23 Farmout Agreement between Grey Wolf Exploration Limited and PrimeWest Energy, Inc. (Previously filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K/A filed on December 9, 2002).

10.24 Farmout Agreement between Grey Wolf Exploration Limited and PrimeWest Energy, Inc. (Previously filed as Exhibit 10.3 to Abraxas' Current Report on Form 8-K/A filed on December 9, 2002).

10.25 Loan And Security Agreement dated as of January 22, 2003, by and among Abraxas, as Borrower, the Subsidiaries of Abraxas that are Signatories thereto, as Guarantors, the Lenders that are Signatories thereto, as Lenders, and Foothill Capital Corporation, as the Arranger and Administrative Agent (Filed as Exhibit 10.5 to Abraxas' Current Report on Form 8-K filed February 6, 2003).

10.26 Intercreditor and Subordination Agreement dated as of January 23, 2003, by and among Foothill, in its capacity as agent (in such capacity, together with any successor in such capacity, the "Senior Agent") for the lenders who are from time to time parties to the Loan Agreement (the "Senior Lenders"), U.S. Bank, N.A., a national banking association in its capacity as trustee (in such capacity, together with any successor in such capacity, the "Trustee") for the holders of the 11 1/2% Secured Notes Due 2007, issued under the Indenture. (Filed as Exhibit 10.6 to Abraxas' Current Report on Form 8-K filed February 6, 2003).

16.1 Letter addressing change in certifying accountant (Filed on Abraxas' Form 8-K filed on August 22, 2001).

21.1 Subsidiaries of Abraxas. (Filed as Exhibit 21.1 to Abraxas, Grey Wolf Exploration Inc., Sandia Oil & Gas Corporation, Sandia Operating Corp., Wamsutter Holdings, Inc., Western Associated Energy Corporation and Eastside Coal Company, Inc.'s Registration Statement on Form S-1, No.

333-103027).

23.1 Consent of Deloitte & Touche LLP (filed herewith).

23.2 Consent of Deloitte & Touche LLP Chartered Accountants (filed herewith).

23.3 Consent of DeGolyer and MacNaughton. (filed herewith).

23.4 Consent of McDaniel & Associates Consultants, Ltd. (filed herewith).

99.1 Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99.2 Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

* Management Compensatory Plan or Agreement.

(b) Reports on Form 8-K

1. Current Report on Form 8-K on November 26, 2002. Other Events, including a press release relating to Purchase and Sale agreement relating to the sale of Canadian properties.

2. Current Report on Form 8-K/A on December 9, 2002. Other Events, including Purchase and Sale agreement and Farmout agreements relating to the sale of Canadian properties.

3. Current Report on Form 8-K on December 10, 2002. Other Events, including a press release announcing exchange offer.

4. Current Report on Form 8-K on December 10, 2002. Other Events, including a press release announcing commitment for new credit facility.

5. Current Report on Form 8-K on December 12, 2002. Other Events, including an amended press release announcing exchange offer.

6. Current Report on Form 8-K on January 8, 2003. Other Events, including a press release extending exchange offer.

7. Current Report on Form 8-K on January 9, 2003. Other Events, including a press release extending exchange offer.

8. Current Report on Form 8-K on January 10, 2003. Other Events, including a press release extending exchange offer.

9. Current Report on Form 8-K on January 13, 2003. Other Events, including a press release extending exchange offer.

10. Current Report on Form 8-K on January 14, 2003. Other Events, including a press release extending exchange offer.

11. Current Report on Form 8-K on January 15, 2003. Other Events, including a press release extending exchange offer.

12. Current Report on Form 8-K on January 24, 2003. Other Events, including

a press release announcing the closing of Canadian Asset Sale, New Secured Credit Facility and completion of exchange offer and redemption of debt.

13. Current Report on Form 8-K on February 6, 2003, Disposition of Assets announcing the completion of the sale of the common stock of Canadian Abraxas and Grey Wolf Exploration, Inc.; Other Event, completion of exchange offer, new credit facility and redemption of notes; Financial Statements and exhibits, including pro forma financial statements giving effect of the sale of Canadian properties, exchange offer, new credit facility and redemption of notes.

14. Current Report on Form 8-K on February 24, 2003, Regulation FD, including press release announcing 2003 capital budget, hedge agreements and resignation of director.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ABRAXAS PETROLEUM CORPORATION

By:/s/ Robert L.G. Watson	By: /s/ Chris E. Williford
President and Principal Executive Officer	Exec. Vice President and Principal Financial and Accounting Officer

DATED: July 22, 2003

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Signature	Name and Title	Date
/s/ Robert L.G. Watson Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	July 22, 2003
/s/ Chris E. Williford Chris Williford	Exec. Vice President and Treasurer (Principal Financial and Accounting Officer)	July 22, 2003
/s/ Craig S. Bartlett, Jr. Craig S. Bartlett, Jr.	Director	July 22, 2003
/s/ Franklin Burke Franklin Burke	Director	July 22, 2003

/s/ Ralph F. Cox	Director	July 22, 2003
Ralph F. Cox		
/s/ James C. Phelps	Director	July 22, 2003
James C. Phelps		
/s/ Joseph A. Wagda	Director	July 22, 2003
Joseph A. Wagda		

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CERTIFICATIONS

I, Robert L. G. Watson, certify that:

1. I have reviewed this annual report on Form 10-K/A of Abraxas Petroleum Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material

weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date: July 22, 2003

/s/ Robert L.G. Watson
Robert L.G. Watson
Chairman of the Board, President and
Principal Executive Officer

CERTIFICATIONS

I, Chris Williford, certify that:

1. I have reviewed this annual report on Form 10-K/A of Abraxas Petroleum Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date: July 22, 2003

/s/ Chris Williford
Chris Williford
Executive Vice President and
Principal Accounting Officer

Exhibit 23.1

Independent Auditors' Consent

We consent to the incorporation by reference in the Registration Statements No. 33-48932, 33-48934, 33-72268, 33-81416, 33-81418, 333-17375, and 333-17377 of Abraxas Petroleum Corporation on Form S-8 of our report dated March 10, 2003, July 18, 2003, as to Note 20 and the first paragraph of "New Accounting Pronouncements" in Note 1, (which report expresses an unqualified opinion and includes two explanatory paragraphs referring to the subsequent events described in Note 2 and the restatement described in Note 20), appearing in this Annual Report on Form 10-K/A of Abraxas Petroleum Corporation for the year ended December 31, 2002.

/s/ Deloitte & Touche LLP

San Antonio, Texas
July 18, 2003

Exhibit 23.2

Independent Auditors' Consent

We consent to the incorporation by reference in the Registration Statements No. 33-48932, 33-48934, 33-72268, 33-81416, 33-81418, 333-17375, and 333-17377 of Abraxas Petroleum Corporation on Form S-8 of our report dated March 10, 2003 on the financial statements of Grey Wolf Exploration Inc. (which report expresses an unqualified opinion and includes an explanatory paragraph relating to our previously issued report on the financial statements of Grey Wolf Exploration Inc. which excluded differences between Canadian and United States generally accepted accounting principles as set out in Note 12, and for U.S. readers has a Canada-U.S. reporting difference which would require an explanatory paragraph relating to the Company's changes in accounting policies and significant subsequent events that have been disclosed in the financial statements), appearing in this Annual Report on Form 10-K/A of Abraxas Petroleum Corporation for the year ended December 31, 2002.

Calgary, Canada /s/ Deloitte & Touche LLP

July 18, 2003 Chartered Accountants

Exhibit 23.3

Consent of DeGolyer and MacNaughton

We hereby consent to the incorporation in your Annual Report on Form 10-K/A of the references to DeGolyer and MacNaughton in the "Reserves Information" section and to the use by reference of information contained in our "Appraisal Report as of December 31, 2002 on Certain Interests owned by Abraxas Petroleum Corporation," Appraisal Report as of December 31,2001 on Certain Interest owned by Abraxas Petroleum Corporation," and "Appraisal Report as of December 31, 2000, on Certain Interest owned by Abraxas Petroleum Corporation" (our Reports). However, that since the crude oil, condensate, natural gas liquids, and natural gas reserves estimates set forth in our Reports have been combined with reserve estimates of other petroleum consultants, we are necessarily unable to verify the accuracy of the reserves values contained in the aforementioned Annual Report.

DeGolyer and MacNaughton

Dallas, Texas
July 22, 2003

Exhibit 23.4

Consent of McDaniel and Associates Consultants LTD.

We consent to the incorporation in your Annual Report on Form 10-K/A of the references to McDaniel and Associates Consultants Ltd. in the "Reserves Information" section and to the use by reference of information contained in our Evaluation Report "Canadian Abraxas Petroleum Ltd., Evaluation of Oil & Gas Reserves, As of January 1, 2002", dated April 3, 2002.

McDaniel & Associates Consultants LTD

Calgary, Alberta
April 3, 2002

Exhibit 99.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the amendment to the Annual Report of Abraxas Petroleum Corporation (the "Company") on Form 10-K/A for the year ended December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert L.G. Watson, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Act of 1934; and (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert L.G. Watson
Robert L.G. Watson
Chairman of the Board, President
and Chief Executive Officer
July 22, 2003

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of ss.18 of the Securities Exchange Act of 1964, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the amendment to the Annual Report of Abraxas Petroleum Corporation (the "Company") on Form 10-K/A for the year ended December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Chris E, Williford, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Act of 1934; and (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Chris E. Williford
Chris E. Williford
Executive Vice President and
Chief Financial Officer
July 22, 2003

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of ss.18 of the Securities Exchange Act of 1964, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Abraxas Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation and Subsidiaries (the "Company") as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2002. 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 audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about 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 audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, on January 23, 2003, the

Company sold all of the outstanding common stock of two wholly owned subsidiaries, Canadian Abraxas Petroleum Limited and Grey Wolf Exploration, Inc., repaid certain debt, and also entered into an agreement to exchange cash, new debt and common stock of the Company for certain other debt.

As discussed in Note 20 to the financial statements, the accompanying 2000, 2001 and 2002 financial statements have been restated.

/s/DELOITTE & TOUCHE LLP
San Antonio, Texas

March 10, 2003 (July 18, 2003, as to Note 20 and the first paragraph of "New Accounting Pronouncements" in Note 1)

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

	(As Restated, see Note 20	
	December 31	
	2001	2002
	(Dollars in thousands)	
Current assets:		
Cash	$ 7,605	$
Accounts receivable:		
Joint owners	2,785	
Oil and gas production sales	4,758	
Other	504	
	8,047	1
Equipment inventory	1,251	
Other current assets	443	
Total current assets	17,346	1
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	486,098	52
Unproved, not subject to amortization	10,626	
Other property and equipment	67,632	4
Total	564,356	57
Less accumulated depreciation, depletion, and amortization	282,462	42

Total property and equipment - net	281,894	15
Deferred financing fees, net of accumulated amortization of $8,668 and $10,763 at December 31, 2001 and 2002, respectively	3,928	
Deferred income taxes....................................	-	
Other assets	448	
Total assets	$ 303,616	$ 18

See accompanying Notes to Consolidated Financial Statements

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	(As Restated, see Note 20	
	December 31	
	2001	2002
	(Dollars in thousands)	
Current liabilities:		
Accounts payable	$ 10,542	$
Joint interest oil and gas production payable	3,596	
Accrued interest	6,013	
Other accrued expenses	1,116	
Hedge liability...	658	
Current maturities of long-term debt	415	6
Total current liabilities..............................	22,340	8
Long-term debt	285,184	23
Deferred income taxes.......................................	20,621	
Future site restoration	4,056	
Commitments and contingencies		
Stockholders' equity (deficit):		
Common stock, par value $.01 per share - authorized 200,000,000 shares; issued 30,145,280 at December 31, 2001 and 2002	301	

Additional paid-in capital	136,830	13
Receivables from stock sale...............................	(97)	
Accumulated deficit	(151,094)	(26
Treasury stock, at cost, 165,883 shares...................	(964)	
Accumulated other comprehensive income (loss).............	(13,561)	(
Total stockholders' equity (deficit)......................	(28,585)	(14
Total liabilities and stockholders' equity (deficit)......	$ 303,616	$ 18

See accompanying Notes to Consolidated Financial Statements

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	(As Restated, see Note	
	Year Ended December	
	2000	2001
	(In thousands except per s	
Revenues:		
Oil and gas production revenues	$ 72,973	$ 73,201
Gas processing revenues.................................	2,717	2,438
Rig revenues	505	756
Other	405	848
	76,600	77,243
Operating costs and expenses:		
Lease operating and production taxes	18,783	18,616
Depreciation, depletion, and amortization	35,857	32,484
Proved property impairment	-	2,638
Rig operations	717	702
General and administrative	6,533	6,445
General and administrative (Stock-based compensation)....	2,767	(2,767
	64,657	58,118
Operating income (loss)..................................	11,943	19,125
Other (income) expense:		
Interest income	(530)	(78
Amortization of deferred financing fees	2,091	2,268
Interest expense	31,140	31,523
Financing costs...	-	-
(Gain) loss on sale of equity investment	(33,983)	845
Gain on debt extinguishment	(1,773)	-

Other	1,563	207
	(1,492)	34,765
Income (loss) before income tax............................	13,435	(15,640
Income tax expense (benefit):		
Current	(1,233)	505
Deferred	4,938	1,897
Minority interest in income of foreign subsidiary (2001 prior to purchase)..................................	1,281	1,676
Net income (loss)....................................	$ 8,449	$ (19,718
Net income (loss) per common share - basic	$ 0.37	$ (0.76
Net income (loss) per common share - diluted...........	$ 0.26	$ (0.76

See Accompanying Notes to Consolidated Financial Statements

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)
(In thousands except share amounts)

	Common Stock		Treasury Stock		Additional Paid-In	Accumulated	Co
	Shares	Amount	Shares	Amount	Capital	Deficit	In
Balance at January 1, 2000..	22,747,099	$ 227	152,083	$ (1,071)	$ 127,562	$ (139,825)	$
Comprehensive income (loss):							
Net income...............	-	-	-	-	-	8,449	
Other comprehensive income:							
Foreign currency translation adjustment	-	-	-		-	-	
Comprehensive income (loss)	-	-	-	-	-	-	
Stock-based compensation expense..	-	-	-	-	2,767	_	
Issuance of common stock and warrants for compensation	12,753	-	(25,000)	185	80	-	
Purchase of treasury stock	-	-	38,800	(78)	-	-	

	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Accumulated Deficit
Balance at December 31, 2000	22,759,852	$ 227	165,883	$ (964)	$ 130,409	$ (131,376)
Comprehensive income (loss):						
Net loss.................	-	-	-	-	-	(19,718)
Other comprehensive income:						
Hedge loss...........	-	-	-	-	-	-
Foreign currency translation adjustment	-	-	-	-	-	-
Comprehensive income (loss)						
Stock-based compensation expense................	-	-	-	-	(2,767)	-
Issuance of common stock for contingent value rights	3,386,488	34	-	-	(34)	-
Issuance of common stock and stock options for acquisition of minority interest in Old Grey Wolf Exploration, Inc.......	3,990,565	40	-	-	9,206	-
Stock options exercised .	8,375	-	-	-	16	-
Balance at December 31, 2001	30,145,280	$301	165,883	$ (964)	$ 136,830	$ (151,094)

(continued)

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)(continued)
(In thousands except share amounts)

	Common Stock		Treasury Stock		Additional		
	Shares	Amount	Shares	Amount	Paid-In Capital	Accumulated Deficit	Co In
Balance at January 1, 2001..	30,145,280	$301	165,883	$ (964)	$ 136,830	$ (151,094)	
Comprehensive income (loss):							
Net loss.................	-	-	-	-	-	(118,527)	
Other comprehensive income:							
Hedge income.........	-	-	-	-	-	-	
Foreign currency translation adjustment	-	-	-	-	-	-	

Comprehensive income (loss)	-	-	-	-	-	-
Balance at December 31, 2002	30,145,280	$ 301	165,883	$ (964)	$ 136,830	$ (269,621)

See accompanying Notes to Consolidated Financial Statements.

ABRAXAS PETROLEUM CORPORATOIN AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	(As Restated, see Note 20)		
	Year Ended December 31		
	2000	2001	20
	(In thousands)		
Operating Activities			
Net income (loss)	$ 8,449	$ (19,718)	$
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Minority interest in income of foreign subsidiary................	1,281	1,676	
Gain on extinguishment of debt....	(1,773)	-	
(Gain) loss on sale of equity investment........................	(33,983)	845	
Depreciation, depletion, and amortization	35,857	32,484	
Proved property impairment	-	2,638	
Deferred income tax expense..........	4,938	1,897	
Amortization of deferred financing fees..............................	2,091	2,268	
Stock-based compensation	2,767	(2,767)	
Issuance of common stock and warrants for compensation	265	-	
Changes in operating assets and liabilities:			
Accounts receivable	(7,036)	12,693	
Equipment inventory	(538)	(76)	
Other	(1,839)	(106)	
Accounts payable	11,318	(14,848)	
Accrued expenses	(425)	(723)	
Net cash provided by (used) in operations.	21,372	16,263	
Investing Activities			
Capital expenditures, including purchases and development of properties	(74,412)	(57,056)	
Proceeds from sale of oil and gas properties............................	21,157	28,938	
Acquisition of minority interest..........	-	(2,679)	

Proceeds from sale of equity investment ..	34,482	-
Net cash used in investing activities.....	(18,773)	(30,797)

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

	Year Ended December	
	2000	2001
	(In thousands)	
Financing Activities		
Purchase of treasury stock, net	$ (78)	$ -
Proceeds from issuance of common stock.....	-	16
Proceeds from long-term borrowings	6,400	29,995
Payments on long-term borrowings	(10,163)	(9,326)
Deferred financing fees	23	-
Net cash (used) provided by financing activities..............................	(3,818)	20,685
Increase (decrease) in cash	(1,219)	6,151
Effect of exchange rate changes on cash.....	(576)	(550)
Increase (decrease) in cash	(1,795)	5,601
Cash at beginning of year	3,799	2,004
Cash at end of year........................	$ 2,004	$ 7,605
Supplemental Disclosures		
Supplemental disclosures of cash flow information:		
Interest paid	$ 33,004	$ 31,752
Taxes paid...........................	$ -	$ 505

Supplemental schedule of noncash investing and financing activities:

In May 2001 the Company issued 3,386,488 shares of common stock upon the expiration of the CVRs issued in connection with the December 1999 exchange. See Note 6.

In September 2001 the Company issued 3,990,565 shares of

common stock and options and paid $2,679,000 million in cash in connection with the acquisition of the minority interest in Old Grey Wolf. See Note 4.

Decrease in oil and gas properties and other assets...	$	(2,925)
Decrease in deferred income tax liability............	$	1,091
Increase in stockholders equity......................	$	(9,246)
Decrease in minority interest in foreign subsidiary...	$	13,759

See accompanying Notes to Consolidated Financial Statements.

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ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2000, 2001 and 2002

1. Organization and Significant Accounting Policies

Nature of Operations

Abraxas Petroleum Corporation (the "Company" or "Abraxas") is an independent energy company engaged in the exploration for and the acquisition, development, and production of crude oil and natural gas primarily along the Texas Gulf Coast, in the Permian Basin of western Texas and in western Canada. The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

The consolidated financial statements include the accounts of the Company, and its wholly owned foreign subsidiaries Canadian Abraxas Petroleum Limited ("Canadian Abraxas") and Grey Wolf Exploration, Inc. ("Grey Wolf"). Minority interest represents the minority shareholders' proportionate share of the equity and income of Grey Wolf prior to the Company's acquisition of the remaining interest in September 2001.

In January 2003, the Company sold all of the common stock of Canadian Abraxas and Grey Wolf. Certain oil and gas properties were retained and transferred into a new wholly owned subsidiary that retained the name Grey Wolf Exploration, Inc. ("New Grey Wolf").

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and

expenses during the reporting period. Actual results could differ from those estimates. Management believes that it is reasonably possible that estimates of proved crude oil and natural gas revenues could significantly change in the future.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables, interest rate and crude oil and natural gas price swap agreements. Accounts receivable are generally from companies with significant oil and gas marketing activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers.

Equipment Inventory

Equipment inventory principally consists of casing, tubing, and compression equipment and is carried at the lower of cost or market.

Oil and Gas Properties

The Company follows the full cost method of accounting for crude oil and natural gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized crude oil and natural gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of crude oil and natural gas properties, less related deferred taxes, are limited, by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not being amortized, if any, plus the lower

of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Excess costs are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of crude oil and natural gas properties, except in unusual circumstances.

Unproved properties represent costs associated with properties on which the Company is performing exploration activities or intends to commence such activities. These costs are reviewed periodically for possible impairments or reduction in value based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased. The Company believes that the unproved properties will be substantially evaluated in six to thirty-six months and it will begin to amortize these costs at such time. During 2000, 2001 and 2002 the Company capitalized $589,000, $164,000 and $152,000 of interest expense respectively, based on the cost of major development projects in progress.

Other Property and Equipment

Other property and equipment are recorded on the basis of cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and betterments are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Hedging

The Company periodically enters into agreements to hedge the risk of future crude oil and natural gas price fluctuations. Such agreements, primarily in the form of price swaps, may either fix or support crude oil and natural gas prices or limit the impact of price fluctuations with respect to the Company's sale of crude oil and natural gas. Gains and losses on such hedging activities are recognized in oil and gas production revenues when hedged production is sold. The net cash flows related to any recognized gains or losses associated with these hedges are reported as cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production required by the contract is delivered.

Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," is effective for the Company on January 1, 2001. SFAS 133, as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. All derivatives, whether designated in hedging relationships or not, will be required to be recorded on the balance sheet at fair value. If the derivative is designated a fair-value hedge, the changes in the fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated a cash-flow hedge, changes in the fair value of the derivative will be recorded in other comprehensive income (OCI) and will be recognized in the income statement when the hedged item affects earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. For a derivative that does not qualify as a hedge, changes in fair value will be recognized in earnings.

Stock-Based Compensation

The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion ("APB") No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of the Company's stock at the date of the grant over the amount an employee must pay to acquire the stock.

Effective July 1, 2000, the Financial Accounting Standards Board ("FASB") issued FIN 44, "Accounting for Certain Transactions Involving Stock Compensation," an interpretation of APB No. 25. Under the interpretation, certain modifications to fixed stock option awards which were made subsequent to December 15, 1998, and were not exercised prior to July 1, 2000, require that the awards be accounted for as variable until they are exercised, forfeited, or expired. In March 1999, the Company amended the exercise price to $2.06 on all options with an existing exercise price greater than $2.06. See Note 7. The Company recognized approximately $2.8 million in expense during 2000 and a credit of $2.8 million during 2001 as General and Administrative (Stock-based compensation). The credit for the year ended December 31, 2001 was due to a decline in the Company's common stock price.

Pro forma information regarding net income (loss) and earnings (loss) per share is required by SFAS 123, "Accounting for Stock-Based Compensation," which also requires that the information be determined as if the Company has accounted for its employee stock options granted subsequent to December 31, 1995 under the fair value method prescribed by that SFAS. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with

the following weighted-average assumptions for 2000, 2001 and 2002, risk-free interest rates of 6.25%, 3.50% and 1.5%, respectively; dividend yields of -0-%; volatility factors of the expected market price of the Company's common stock of ..916, .35 and .35, respectively; and a weighted-average expected life of the option of ten years.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because the Company's employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its employee stock options.

For purposes of pro forma disclosures, the estimated fair value of the options is amortized to expense over the options' vesting period. The Company's pro forma information follows:

	Year Ended December 31		
	2000	2001	2002
Net income (loss) as reported	$ 8,449	$ (19,718)	$ (118,52
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	2,767	(2,767)	
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,127)	(1,284)	(6
Pro forma net income (loss)	$ 10,089	$ (23,769)	$ (119,1
Earnings (loss) per share:			
Basic - as reported	$ 0.37	$ (0.76)	$ (3.9
Basic - pro forma	$ 0.45	$ (0.92)	$ (3.9
Diluted - as reported	$ 0.26	$ (0.76)	$ (3.9
Diluted - pro forma	$ 0.31	$ (0.92)	$ (3.9

Foreign Currency Translation

The functional currency for Canadian Abraxas and Grey Wolf (Old and New) is the Canadian dollar ($CDN). The Company translates the functional currency into U.S. dollars ($US) based on the current exchange rate at the end of the period for the balance sheet and a weighted average rate for the period on the statement of operations. Translation adjustments are reflected as Accumulated Other Comprehensive Income (Loss) in Stockholders' Equity (Deficit). See Note 2

for Canadian subsidiaries sold in 2003. A portion of the translation account will be eliminated at the closing of the sale in 2003.

Fair Value of Financial Instruments

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the book value. The Company assumes the book value of those financial instruments that are classified as current approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

Restoration, Removal and Environmental Liabilities

The estimated costs of restoration and removal of facilities are accrued on a straight-line basis over the life of the property. The estimated future costs for known environmental remediation requirements are accrued when it is probable that a liability has been incurred and the amount of remediation costs can be reasonably estimated. These amounts are the undiscounted, future estimated costs under existing regulatory requirements and using existing technology.

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Revenue Recognition

The Company recognizes crude oil and natural gas revenue from its interest in producing wells as crude oil and natural gas is sold from those wells, net of royalties. Revenue from the processing of natural gas is recognized in the period the service is performed. The Company utilizes the sales method to account for gas production volume imbalances. Under this method, income is recorded based on the Company's net revenue interest in production taken for delivery. The Company had no material gas imbalances.

Deferred Financing Fees

Deferred financing fees are being amortized on a level yield basis over the term of the related debt arrangements.

Income Taxes

The Company records income taxes using the liability method. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse.

New Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS No. 141 and 142 clarify that more assets should be distinguished and classified between tangible and intangible. The Company did not change or

reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. The Company believes the treatment of such mineral rights as tangible assets under the full cost method of accounting for crude oil and natural gas properties is appropriate. An issue has arisen regarding whether contractual mineral rights should be classified as intangible rather that tangible assets. If it is determined that reclassification is necessary, the Company's oil and gas properties would be reduced by $868,000 and $3.1 million and intangible assets would have increased by a like amount at December 31, 2001 and 2002, respectively, representing cost incurred from the effective date of June 30, 2001. The provisions of SFAS No. 141 and 142 impact only the balance sheet and associated footnote disclosure, and reclassifications necessary would not impact the Company's cash flows or results of operations.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 is effective for us January 1, 2003. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense.

We have completed our assessment of SFAS No. 143 and based on our estimates, we do not expect the statement to have a material effect on our financial position, results of operations and cash flows for future periods. At January 1, 2003 , we estimate that the present value of our future Asset Retirement Obligation ("ARO") for natural gas and oil property and related equipment is approximately $657,000. We estimate that the cumulative effect to the adoption of SFAS No. 143 and the change in the accounting principal will be a loss of $285,000, which will be recorded in the first quarter of 2003. The impact on each of the prior periods was not material.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Asset." Effective January 1, 2002, the Company adopted SFAS No. 144. SFAS No. 144 retains the requirement to recognize

an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS No. 144, among other things, changes the criteria that have to be met to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. This new standard had no impact on the Company's consolidated financial statements for the year ended December 31, 2002.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB No. 4, 44, and 64, Amendments of FASB Statement No. 13 and Technical Corrections." SFAS No. 145 clarifies guidance related to the reporting of gains and losses from extinguishment of debt and resolves inconsistencies related to the required accounting treatment of certain lease modifications. SFAS No. 145 also amends

other existing pronouncements to make various technical corrections, clarify meanings or describe their applicability under changed conditions. The provisions relating to the reporting of gains and losses from extinguishment of debt become effective for us beginning January 1, 2003. All other provisions of this standard were effective for the Company as of May 15, 2002 and did not have an impact on the Company's financial condition or results of operations. Upon issuance of our restated financial statements, see Note 20, the Company has reclassified the gain on the early extinguishment of debt in 2000 from an extraordinary item to other income. This reclassification did not affect net income for the year ended December 31, 2000.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 requires costs associated with exit of disposal activities to be recognized when they are incurred rather than at the date of commitment to an exit or disposal plan. SFAS No. 146 is effective for us beginning January 1, 2003. The Company is currently evaluating the impact the standard will have on its results of operations and financial condition.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-based Compensation--Transition and Disclosure, an amendment of FASB Statement No. 123," which amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions of SFAS No. 123 to require prominent disclosure 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. The provisions of SFAS No. 148 are effective for annual financial statements for fiscal years ending after December 15, 2002, and for financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. The Company will continue to use APB No. 25 to account for stock based compensation, while providing the disclosures required by SFAS 123 as amended by SFAS 148.

Reclassifications

Certain prior years balances have been reclassified for comparative purposes.

2. Recent Events

Exchange Offer. On January 23, 2003, the Company completed an exchange offer, pursuant to which it offered to exchange cash and securities for all of the outstanding 11 1/2% Senior Secured Notes due 2004, Series A ("Second Lien Notes") and 11 1/2% Senior Notes due 2004, Series D, ("Old Notes") issued by Abraxas and Canadian Abraxas. In exchange for each $1,000 principal amount of such notes tendered in the exchange offer, tendering note holders received:

- cash in the amount of $264;
- an 11 1/2% Secured Note due 2007, Series A, ("New Notes") with a principal amount equal to $610; and
- 31.36 shares of Abraxas common stock.

At the time the exchange offer was made, there were approximately $190.2 million of the Second Lien Notes and $801,000 of the Old Notes outstanding - see Note 3. Holders of approximately 94% of the aggregate outstanding principal amount of the Second Lien Notes and Old Notes tendered their notes for exchange in the offer. Pursuant to the procedures for redemption under the applicable indenture provisions, the remaining 6% of the aggregate outstanding principal amount of the Second Lien Notes and Old Notes were redeemed at 100% of the principal amount plus accrued and unpaid interest, for approximately $11.5

million ($11.1 million in principal and $0.4 million in interest). The indentures for the Second Lien Notes and Old Notes have been duly discharged. In connection with the exchange offer, Abraxas made cash payments of approximately $47.5 million and issued approximately $109.7 million in principal amount of New Notes and 5,642,699 shares of Abraxas common stock. Fees and expenses incurred in connection with the exchange offer were approximately $3.8 million ($967,000 was charged to expense in 2002 and is included in financing costs in the accompanying statement of operations). The balance will be charged to expense in 2003 as the cost are incurred.

New Notes. The new notes will accrue interest from the date of issuance, at a fixed annual rate of 11 1/2%, payable in cash semi-annually on each May 1 and November 1, commencing May 1, 2003, provided that, if the Company fails, or are not permitted pursuant to the new senior secured credit agreement or the intercreditor agreement between the trustee under the indenture for the New Notes and the lenders under the new senior secured credit agreement, to make such cash interest payments in full, the Company will pay such unpaid interest in kind by the issuance of additional notes with a principal amount equal to the amount of accrued and unpaid cash interest on the notes plus an additional 1% accrued interest for the applicable period. Upon an event of default, interest will accrue at an annual rate of 16.5%. The New Notes are guaranteed by all of Abraxas' current subsidiaries, Sandia Oil & Gas Corp., Sandia Operating Corp., Wamsutter Holdings, Inc., Western Associated Energy Corporation, Eastside Coal Company, Inc., and New Grey Wolf, and will be guaranteed by all of Abraxas' future subsidiaries. The New Notes are secured by a second lien or charge on all of the Company's current and future assets, including, but not limited to, its crude oil and natural gas properties.

Redemption of First Lien Notes. On January 24, 2003, the Company completed the redemption of 100% of our outstanding 12?% Senior Secured Notes, Series A, ("First Lien Notes") - see Note 4, with approximately $66.4 million of the proceeds from the sale of Canadian Abraxas and Old Grey Wolf. Prior to the redemption, the Company had $63.5 million of its First Lien Notes outstanding. Under the terms of the indenture for the First Lien Notes the Company had the right to redeem the First Lien Notes at 100% of the outstanding principal amount of the notes, plus accrued and unpaid interest to the date of redemption, and to discharge the indenture upon call of the First Lien Notes for redemption and deposit of the redemption funds with the trustee. The Company exercised these rights on January 23, 2003 and upon the discharge of the indenture, the trustee released the collateral securing the Company's obligations under the First Lien Notes.

New Senior Secured Credit Agreement. Contemporaneously with the closing of the exchange offer and the sale of Canadian Abraxas and Old Grey Wolf, on January 23, 2003, Abraxas entered into a new senior secured credit agreement providing a term loan facility of $4.2 million and a revolving credit facility with a maximum borrowing base of up to $50 million. Subject to earlier termination on the occurrence of events of default or other events, the stated maturity date for both the term loan facility and the revolving credit facility is January 22, 2006. In the event of an early termination, we will be required to pay a prepayment premium, except in the limited circumstances described in the new senior secured credit agreement. Outstanding amounts under both facilities bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 4.5%. Any amounts in default under the term loan facility will accrue interest at an additional 4%. At no time will the amounts outstanding under the new senior secured credit agreement bear interest at a rate less than 9%.

Term Loan Facility. Abraxas has borrowed $4.2 million pursuant to a term

loan facility at January 23, 2003, all of which was used to make cash payments in connection with the financial restructuring. Accrued interest under the term loan facility will be capitalized and added to the principal amount of the term loan facility until maturity.

Revolving Credit Facility. Lenders under the new senior secured credit agreement have provided a revolving credit facility to Abraxas with a maximum borrowing base of up to $50 million. Our current borrowing base under the revolving credit facility is $49.9 million, subject to adjustments based on periodic calculations and mandatory prepayments under the senior secured credit agreement. Portions of accrued interest under the revolving credit facility may be capitalized and added to the principal amount of the revolving credit facility. At January 23, 2003, the Company has borrowed $42.5 million under the revolving credit facility, all of which was used to make cash payments in connection with the financial restructuring. The Company plans to use the remaining borrowing availability under the new senior secured credit agreement to fund its operations, including capital expenditures.

Covenants. Under the new senior secured credit agreement, Abraxas is subject to customary covenants and reporting requirements. Certain financial covenants require Abraxas to maintain minimum levels of consolidated EBITDA (as defined in the new senior secured credit agreement), minimum ratios of consolidated EBITDA to cash interest expense and a limitation on annual capital expenditures. In addition, at the end of each fiscal quarter, if the aggregate amount of our cash and cash equivalents exceeds $2.0 million, the Company is required to repay the loans under the new senior secured credit agreement in an amount equal to such excess. The new senior secured credit agreement also requires the Company to enter into hedging agreements on not less than 25% or more than 75% of our projected oil and gas production. We are also required to establish deposit accounts at financial institutions acceptable to the lenders and we are required to direct our customers to make all payments into these accounts. The amounts in these accounts will be transferred to the lenders upon the occurrence and during the continuance of an event of default under the new senior secured credit agreement.

In addition to the foregoing and other customary covenants, the new senior secured credit agreement contains a number of covenants that, among other things, restrict the Company's ability to:

- incur additional indebtedness;
- create or permit to be created any liens on any of our properties;

- enter into any change of control transactions;
- dispose of our assets;
- change our name or the nature of our business;
- make any guarantees with respect to the obligations of third parties;
- enter into any forward sales contracts;
- make any payments in connection with distributions, dividends or redemptions relating to our outstanding securities, or
- make investments or incur liabilities.

Guarantees. The obligations of Abraxas under the new senior secured credit agreement are guaranteed by Sandia Oil & Gas, Sandia Operating, Wamsutter, New Grey Wolf, Western Associated Energy and Eastside Coal. Obligations under the new senior secured credit agreement are secured by a first lien security interest in substantially all of Abraxas' and the guarantors' assets, including all crude oil and natural gas properties.

Events of Default. The new senior credit facility contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

Sale of Stock of Canadian Abraxas and Old Grey Wolf. Contemporaneously with the closing of the exchange offer, on January 23, 2003, Abraxas completed the sale to a wholly owned subsidiary of PrimeWest Energy Inc. of all of the outstanding capital stock of Canadian Abraxas and Old Grey Wolf for approximately $138 million before net adjustments of $3.4 million. The aggregate sales price for the shares was as follows:

	Number of Shares	Sales Price
Canadian Abraxas	5,751 common shares	$68 million
Old Grey Wolf	12,804,628 common shares	$70 million
	Total Sales Price:	$138 million

After sales price adjustments and related costs and expenses of approximately $5.9 million were made, the sales price realized for the sale of Canadian Abraxas and Old Grey Wolf was $132.1 .million. Upon consummation of the sale, Old Grey Wolf repaid the then current outstanding indebtedness under its credit agreement with Mirant Canada Energy Capital, Ltd. ("Grey Wolf Facility") in the amount of $46.3 million - see Note 3, which reduced the net proceeds from the sale by a corresponding amount. The net cash proceeds from the sale were $85.8 million, all of which has been utilized in connection with the financial restructuring. The Company estimates a gain on the sale of Canadian Abraxas and Old Grey Wolf of approximately $69 million at the time of closing in 2003.

Under the terms of the agreement with PrimeWest, Abraxas has retained certain oil and gas properties formerly held by Canadian Abraxas and Old Grey Wolf, including all of Canadian Abraxas' and Old Grey Wolf's undeveloped acreage existing at the time of the sale, which includes all of our interests in the Ladyfern area. These assets have been contributed to New Grey Wolf. Portions of this undeveloped acreage will be developed by PrimeWest and New Grey Wolf under a farmout arrangement. Under the farmout arrangements, PrimeWest has agreed to participate in the development of certain lands of New Grey Wolf in the Caroline and Pouce Coupe areas of Alberta. PrimeWest has the right to earn a 60% interest in certain wells if it bears 100% of the expense of drilling such wells. In addition, New Grey Wolf and PrimeWest will have an area of mutual interest in respect of the lands surrounding the Caroline area where each party will be entitled to participate in the acquisition of the other, with New Grey Wolf participating with a 40% interest and PrimeWest participating with a 60% interest.

The following presents the summarized results of operations for the years ended December 31, 2000, 2001, and 2002, for the Canadian properties which were not retained after the transaction in January 2003.

	Year ended December 31, 2000	2001	2002
Total revenue	$ 43,714	$ 41,468	$ 32,013
Loss from operations before income tax	(1,707)	(102)	(87,378)
Income tax expense (benefit)	272	1,897	(29,697)
Minority interest in income	(1,281)	(1,676)	--
Loss from operations	$ (3,260)	$ (3,675)	$(57,681)

Assets and liabilities related to the Canadian properties which were not retained after the January 2003 transaction:

	December 31, 2002
Assets:	
Cash	$ 4,325
Accounts receivable	4,016
Net property and equipment	54,468
Other	11,438
	$ 74,247
Liabilities:	
Accounts payable and accrued liabilities	$ 7,320
Long-tern debt	45,964
Other	3,413
	$ 56,697

Included in the loss from operations shown above are interest expense of $8.3 million, $7.6 million, and $9.5 million, and general and administrative expense of $1.7 million, $1.5 million, and $1.7 million for the years ended December 31, 2000, 2001 and 2002, respectively. The interest expense represents the amounts relating to an Old Grey Wolf senior credit facility which was repaid in conjunction with the transactions described above and the amounts related to the balance of certain noted (approximately $52.6 million) which had historically been reflected by Canadian Abraxas. At the time of the subsidiary sale, the balance of the outstanding notes were transferred to the parent and subject to the financial restructuring described in Note 3. The general and administrative expense of the Canadian subsidiaries above were determined by considering the on-going general and administrative cost associated with the Canadian properties retained by the Company.

3. Long-Term Debt

As described in Note 2, the First Lien Notes were redeemed in January 2003. The Old Notes and the Second Lien Notes were either redeemed or exchanged for cash, common stock and New Notes in January 2003. Additionally, the 9.5% Mirant Canada Energy Capital, Ltd. credit facility, with a balance outstanding at December 31, 2002 of $45.9 million, was repaid in connection with the sale of the common stock of Old Grey Wolf in January 2003.

The following is a brief description of the Company's debt as of December 31, 2002. The pro forma unaudited information reflects the impact of the financial restructuring transactions - see Note 2.

Long-term debt consists of the following:

	December 31	
	2001	2002
	(In thousa	
11.5% Senior Notes due 2004 ("Old Notes")	$ 801	$
12.875% Senior Secured Notes due 2003 ("First Lien Notes")	63,500	63
11.5% Second Lien Notes due 2004 ("Second Lien Notes").............	190,178	190
9.5% Senior Credit Facility ("Grey Wolf Facility") providing for borrowings up to approximately US $96 million (CDN $150 million). Secured by the assets of Old Grey Wolf and non-recourse to Abraxas.......................................	22,944	45
11.5% Secured Notes due 2007 ("New Notes") - January 2003..........	-	
New Senior Secured Credit Agreement - January 2003.................	-	
Production Payment	8,176	
	285,599	300
Less current maturities	415	63
	$ 285,184	$ 236

(a) After transactions described in Note 2, for financial reporting purposes, the New Notes will be reflected at the carrying value of the Second Lien Notes and Old Notes prior to the exchange of $191.0 million, net of the cash offered in the exchange of $47.5 million and net of the fair market value related to equity of $3.8 million offered in the exchange. In conjunction with the financial restructuring transaction, Abraxas paid cash of $11.5 million ($11.1 million in principal and $0.4 million in interest) to redeem certain of the outstanding old debt and accrued interest. The result of all of these items will be a remaining carrying value of the New Notes of $128.6 million. The face amount of the New Notes is $109.7 million. See Note 2 for terms and conditions of the New Notes and the New Senior Secured Credit Agreement.

Old Notes. Interest on the Old Notes is payable semi-annually in arrears on May 1 and November 1 of each year at the rate of 11.5% per annum. The Old Notes are redeemable, in whole or in part, at the option of the Company.

First Lien Notes. Interest on the First Lien Notes is payable semi-annually in arrears on March 15 and September 15 of each year at the rate of 12.875% per annum.

Second Lien Notes. Interest on the Second Lien Notes is payable semi-annually in arrears on May 1 and November 1, commencing May 1, 2000.

Production Payment

In October 1999, the Company entered into a non-recourse dollar denominated production payment agreement (the "Production Payment") with a third party. The Production Payment had an aggregate total availability of up to $50 million at 15% interest. The Production Payment related to a portion of the production from several natural gas wells in South Texas. The Company reacquired the Production Payment in June 2002, for approximately $6.8 million.

Early Debt Extinguishment

In June 2000, the Company retired $3.5 million of the Old Notes and $3.6 million of the Second Lien Notes at a discount of $1.8 million initially reflected as a gain. Upon reissuance of our financial statements, see Note 20, the Company has reclassified this gain from an extraordinary item to other income. This reclassification did not affect net income for the year ended December 31, 2000.

4. Acquisitions and Divestitures

Abraxas Wamsutter L.P. Divestiture

In November 1998, the Company sold its interest in certain Wyoming properties to Abraxas Wamsutter L.P., a Texas limited partnership (the "Partnership"), for approximately $58.6 million and a minority equity ownership in the Partnership. Wamsutter Holdings, Inc. ("Wamsutter") initially owned a one percent interest and acted as general partner of the Partnership. The investment in the Partnership was accounted for by the equity method. After certain payback requirements were satisfied, the Company's interest would increase to 35% initially and could increase to as high as 65%. The Company also received a management fee and reimbursement of certain overhead costs from the Partnership which amounted to $112,700 for the year ended December 31, 2000.

In March 2000, the Partnership sold all of its interest in its crude oil and natural gas properties to a third party. Prior to the sale of these

properties, effective January 1, 2000, the Company's equity investee share of oil and gas property cost, results of operations and amortization were not material to consolidated operations or financial position. As a result of the sale, the Company received approximately $34 million, which represented a proportional interest in the Partnership's proved properties. See Note 10 regarding a litigation provision in 2001 of $845,000 related to ad valorem taxes.

Acquisition of Minority Interest in Old Grey Wolf

In September 2001, the Company completed a tender offer for the minority interest in Old Grey Wolf, acquiring the approximately 52% of capital stock that was not previously owned by the Company. The Company issued 3,990,565 common shares and 588,916 stock options, valued together at approximately $9.2 million. Additionally, the Company incurred direct costs of approximately $2.7 million related to the acquisition. The elimination of the minority interest through an acquisition at a purchase price less than Old Grey Wolf's book value in the Company's consolidated financial statements had the effect of reducing the property and other assets balances by $2.9 million and deferred income taxes by $1.1 million.

The Company sold all of the common stock in Old Grey Wolf in January 2003 - see Note 2.

5. Property and Equipment

The major components of property and equipment, at cost, are as follows:

	Estimated Useful Life	December 31, 2001	December 31, 2002
	Years	(In thousands)	
Land, buildings, and improvements	15	$ 318	$ 331
Crude oil and natural gas properties	-	496,724	529,047
Natural Gas Processing	18	63,964	38,735
Equipment and other	7	3,350	5,123
		$564,356	$573,236

6. Stockholders' Equity

Common Stock

See Note 2 - Recent Events for common stock issued in January 2003 as part of an exchange offer.

In 1994, the Board of Directors adopted a Stockholders' Rights Plan and declared a dividend of one Common Stock Purchase Right ("Rights") for each share of common stock. The Rights are not initially exercisable. Subject to the Board of Directors' option to extend the period, the Rights will become exercisable and will detach from the common stock ten days after any person has become a beneficial owner of 20% or more of the common stock of the Company or has made a tender offer or Exchange Offer (other than certain qualifying offers) for 20% or more of the common stock of the Company.

Once the Rights become exercisable, each Right entitles the holder, other than the acquiring person, to purchase for $40 a number of shares of the Company's common stock having a market value of two times the purchase price. The Company may redeem the Rights at any time for $.01 per Right prior to a specified period of time after a tender or Exchange Offer. The Rights will expire in November 2004, unless earlier exchanged or redeemed.

Contingent Value Rights ("CVRs")

As part of an exchange offer consummated by the Company in December 1999, Abraxas issued contingent value rights or CVRs, which entitled the holders to receive up to a total of 105,408,978 of Abraxas common stock under certain circumstances, as defined. In May 2001, Abraxas issued 3,386,488 shares upon the expiration of the CVRs.

Treasury Stock

In March 1996, the Board of Directors authorized the purchase in the open market of up to 500,000 shares of the Company's outstanding common stock, the aggregate purchase price not to exceed $3,500,000. During the year ended December 31, 2000, 38,800 shares with an aggregate cost of $78,000 were purchased. During the years ended December 31, 2001 and 2002, the Company did not purchase any shares of its common stock for treasury stock.

7. Stock Option Plans and Warrants

Stock Options

The Company grants options to its officers, directors, and key employees under various stock option and incentive plans.

During 2001, the Company's stockholders approved an amendment to the Abraxas Petroleum Corporation 1994 Long Term Incentive Plan to increase the number of shares of Abraxas common stock reserved for issuance under the plan to 5,000,000. The additional shares were necessary to accommodate the grant of Abraxas options to Old Grey Wolf option holders in connection with the acquisition of the minority interest in Old Grey Wolf in September 2001 (see Note 5), and for the re-issuance of outstanding options granted under the Abraxas Petroleum Corporation 2000 Long Term Incentive Plan, which was terminated in 2001. The options were re-issued at the same exercise price and term as the original issuances.

The Company's various stock option plans have authorized the grant of options to management, employees and directors for up to approximately 5.7 million shares of the Company's common stock. All options granted have ten year terms and vest and become fully exercisable over three to four years of continued service at 25% to 33% on each anniversary date. At December 31, 2002 approximately 2.2 million options remain available for grant.

A summary of the Company's stock option activity, and related information for the years ended December 31, follows:

	Options (000s)	Weighted-Average Exercise Price	Options (000s)	Weighted-Average Exercise Price (1)	Options (000s)
Outstanding-beginning of year	1,890	$ 1.82	4,042	$ 3.37	4,942
Granted	2,240	4.62	918	2.81	521
Exercised	-	-	(8)	1.95	-
Forfeited/Expired	(88)	1.89	(10)	1.79	(2,158
Outstanding-end of year ...	4,042	$ 3.37	4,942	$ 3.28	3,305
Exercisable at end of year	1,067	$ 1.99	2,259	$ 2.65	2,136
Weighted-average fair value of options granted during the year		$ 1.21		$ 1.19	

(1) In September 2001, the Abraxas Petroleum Corporation 2000 Long Term Incentive Plan was terminated, and options granted under the plan were

reissued under the Abraxas Petroleum Corporation 1994 Long Term Incentive Plan at the same option price and term.

The following table represents the range of option prices and the weighted average remaining life of outstanding options as of December 31, 2002:

	Options outstanding			
Exercise price	Number outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable
$0.50 - 0.97	795,000	8.8	$ 0.77	300,000
$1.22 - 1.85	688,996	6.9	1.46	336,895
$2.01 - 2.21	1,507,494	4.5	2.08	1,394,107
$3.00 - 3.71	79,812	6.5	3.11	43,609
$4.13 - 4.83	234,035	8.1	4.82	61,538

Stock Awards

In addition to stock options granted under the plans described above, the 1994 Long-Term Incentive Plan also provides for the right to receive compensation in cash, awards of common stock, or a combination thereof. There were no awards in 2000, 2001 or 2002.

The Company also has adopted the Restricted Share Plan for Directors which provides for awards of common stock to non-employee directors of the Company who did not, within the year immediately preceding the determination of the director's eligibility, receive any award under any other plan of the Company. In 2000, the Company made direct awards of common stock of 12,753 shares, at weighted average fair value $0.94 per share. The Company recorded compensation expense of $11,900 for the year ended December 31, 2000. There were no direct awards of common stock in 2001 or 2002.

Stock Warrants and Other

In 2000, the Company issued 950,000 warrants in conjunction with a consulting agreement. Each is exercisable for one share of common stock at an exercise price of $3.50 per share. These warrants have a four-year term beginning July 1, 2000. The Company recorded approximately $219,000 of compensation expense which is included in other expense in 2000. In addition, the Company paid cash compensation of $360,000 and $191,000 in 2000 and 2001, respectively, under the agreement.

At December 31, 2002, the Company has approximately 6.4 million shares reserved for future issuance for conversion of its stock options, warrants, and incentive plans for the Company's directors, employees and consultants.

8. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of

the Company's deferred tax liabilities and assets are as follows:

	December 3
	2001
	(In thousan
Deferred tax liabilities:	
U.S. full cost pool	$ 2,714
Canadian full cost pool	24,809
Total deferred tax liabilities	27,523
Deferred tax assets:	
U.S. full cost pool	-
Canadian full cost pool	-
Depletion	2,035
Net operating losses ("NOL")	42,264
Investment in foreign subsidiaries	-
Other	2,273
Total deferred tax assets	46,572
Valuation allowance for deferred tax assets	(39,670)
Net deferred tax assets	6,902
Net deferred tax liabilities (assets)	$ 20,621

Significant components of the provision (benefit) for income taxes are as follows:

	2000	2001
Current:		
Federal	$ -	$ 505
Foreign	(1,233)	-
	$ (1,233)	$ 505
Deferred:		
Federal	$ 3,433	$ -
Foreign	1,505	1,897
	$ 4,938	$ 1,897

At December 31, 2002 the Company had, subject to the limitation discussed below, $166.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2003 through 2022 if not utilized. At December 31, 2002, the Company had approximately US $1.0 million of net operating loss carryforwards for Canadian tax purposes. These carryforwards will expire from 2003 through 2009 if not utilized. In connection with the January 2003 transactions described in Note 2, certain of the loss carryforward may be utilized.

At December 31, 2002, the Company was no longer permanently reinvested with respect to its foreign subsidiaries, see Note 2. As a result, the Company recorded net deferred tax assets of $32.0 million related to its investment in foreign subsidiaries, offset by an equivalent valuation allowance due to uncertainties as to the future utilization of these amounts.

As a result of the acquisition of certain partnership interests and crude oil and natural gas properties in 1990 and 1991, an ownership change under Section 382 occurred in December 1991. Accordingly, it is expected that the use of the U.S. net operating loss carryforwards generated prior to December 31, 1991 of $3.2 million will be limited to approximately $235,000 per year.

During 1992, the Company acquired 100% of the common stock of an unrelated corporation. The use of net operating loss carryforwards of the acquired corporation of $257,000 acquired in the acquisition are limited to approximately $115,000 per year.

As a result of the issuance of additional shares of common stock for acquisitions and sales of common stock, an additional ownership change under Section 382 occurred in October 1993. Accordingly, it is expected that the use of all U.S. net operating loss carryforwards generated through October 1993 (including those subject to the 1991 and 1992 ownership changes discussed above) of $6.6 million will be limited as described above and in the following paragraph.

An ownership change under Section 382 occurred in December 1999, following the issuance of additional shares, as described in Note 4. It is expected that the annual use of U.S. net operating loss carryforwards subject to this Section 382 limitation will be limited to approximately $363,000, subject to the lower limitations described above. Future changes in ownership may further limit the use of the Company's carryforwards. In 2000 assets with built in gains were sold, increasing the Section 382 limitation for 2001 by approximately $31.0 million.

The annual Section 382 limitation may be increased during any year, within 5 years of a change in ownership, in which built-in gains that existed on the date of the change in ownership are recognized.

In addition to the Section 382 limitations, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, the Company has established a valuation allowance of $39.7 million and $99.1 million for deferred tax assets at December 31, 2001 and 2002, respectively.

The reconciliation of income tax computed at the U.S. federal statutory tax rates to income tax expense is:

	December 31		
	2000	2001	2002
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	$ (3,965)	$ 5,318	$ 51,878
(Increase) decrease in deferred tax asset valuation allowance	1,371	(4,907)	(59,456)
NOL utilization - gain on debt........	(603)	-	-
Write-down of non-tax basis assets....	-	(2,194)	(7,009)
Higher effective rate of foreign operations.........................	(1,098)	(136)	7,349
Percentage depletion	363	596	683
Investment in foreign subsidiaries ..	-	-	35,604
Other	227	(1,079)	648
	$ (3,705)	$ (2,402)	$ 29,697

9. Related Party Transactions

Accounts receivable - Other includes approximately $48,365 and $51,211 as of December 31, 2001 and 2002, respectively, representing amounts due from officers and stockholders relating to advances made to employees.

Wind River Resources Corporation ("Wind River"), all of the capital stock of which is owned by the Company's President, owns a twin-engine airplane. The airplane is available for business use by the employees of the Company from time to time. The Company paid Wind River a total of $336,000, $314,000 and $345,000 in 2000, 2001 and 2002 respectively, for Wind River's operating cost associated with the Company's use of the plane.

10. Commitments and Contingencies

Operating Leases

During the years ended December 31, 2000, 2001 and 2002, the Company incurred rent expense related to leasing office facilities of approximately $465,000, $519,000 and $236,000, respectively. Future minimum rental payments are as follows at December 31, 2002.

2003	$ 336,000
2004	236,000
2005	236,000
2006	177,000
Thereafter	-

Litigation and Contingencies

In 2001 the Company and the Partnership (see Note 4) were named in a lawsuit filed in U.S. District Court in the District of Wyoming. The claim asserts breach of contract, fraud and negligent misrepresentation by the Company

related to the responsibility for year 2000 ad valorem taxes on crude oil and natural gas properties sold by the Company and the Partnership. In February 2002, a summary judgment was granted to the plaintiff in this matter and a final judgment in the amount of $1.3 million was entered. The Company has filed an appeal. The Company believes these charges are without merit. The Company has established a reserve in the amount of $845,000, which represents the Company's interest in the judgment. In 2002 the Company recorded $201,000 in other expense representing its share of the ongoing legal cost related to this matter.

In late 2000, the Company received a Final De Minimis Settlement Offer from the United States Environmental Protection Agency concerning the Casmalia Disposal Site, Santa Barbara County, California. The Company's liability for the cleanup at the Superfund site is based on a 1992 acquisition, which is alleged to have transported or arranged for the transportation of oil field waste and drilling muds to the Superfund site. The Company has engaged California counsel to evaluate the notice of proposed de minimis settlement and its notice of potential strict liability under the Comprehensive Environmental Response, Compensation and Liability Act. Defense of the action is handled through a joint group of oil companies, all of which are claiming a petroleum exclusion that limits the Company's liability. The potential financial exposure and any settlement posture has yet not been developed, but is considered by the Company to be immaterial.

Additionally, from time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2002, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

11. Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	2000	2001	
Numerator:			
Numerator for basic and diluted earnings per share - net income (loss) available to common stockholders	$ 8,449,000	$ (19,718,000)	$ (
Denominator:			
Denominator for basic earnings per share - weighted-average shares	22,615,777	25,788,571	
Effect of dilutive securities:			
Stock options, warrants and CVRs...............	10,011,987	-	
Dilutive potential common shares Denominator for diluted earnings per share - adjusted weighted-average shares and assumed conversions..................................	32,627,764	25,788,571	

Basic earnings (loss) per share:

Net income (loss) per common share..........	$ 0.37	$ (0.76)	$
Diluted earnings (loss) per share:			
Net income (loss) per common share - diluted.	$ 0.26	$ (0.76)	$

For the year ended December 31, 2000, 2001 and 2002, 3.0 million shares, 4.3 million shares and 5.9 million shares respectively, were excluded from the calculation of diluted earnings per share since their inclusion would have been anti-dilutive.

12 Quarterly Results of Operations (Unaudited)

The operating results for each of the quarters in the two year period ended December 31, 2002 have been restated to give effect to the restatement related to amounts previously reported as discontinued operations being reflected as continuing operations, as discussed in Note 20.

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2001 and 2002 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter
	(In thousands, except per share data)		
Year Ended December 31, 2001			
Net revenue - as reported	$ 13,217	$ 9,818	$ 7,777
Net revenue - as restated...........	29,086	21,116	14,901
Operating income (loss) - as reported.	4,709	5,565	2,284
Operating income (loss) - as restated.	12,112	9,002	2,113
Net income (loss) - as reported......	255	(1,274)	(5,849)
Net income (loss) - as restated......	255	(1,274)	(5,849)
Net income (loss) per common share - basic and diluted - as reported.....	$ 0.01	$ (0.05)	$ (0.22)
Net income (loss) per common share - basic and diluted - as restated.....	$ 0.01	$ (0.05)	$ (0.22)

Year Ended December 31, 2002			
Net revenue - as reported............	$ 4,616	$ 5,759	$ 5,012
Net revenue - as restated...........	11,807	14,235	11,061
Operating income (loss) - as reported.	(741)	(33,282)	(560)
Operating income (loss) - as restated	(735)	(115,879)	490
Net income (loss) - as reported.......	(8,699)	(95,690)	(8,438)
Net income (loss) - as restated.......	(8,699)	(95,690)	(8,438)
Net income (loss) per common share - basic and diluted - as reported.....	$ (0.29)	$ (3.19)	$ (0.28)
Net income (loss) per common share- basic and diluted - as restated.....	$ (0.29)	$ (3.19)	$ (0.28)

During the second quarter of 2002, the Company incurred a ceiling limitation write-down of $116.0 million. During the fourth quarter of 2001, the Company incurred a ceiling limitation write-down of $2.6 million, which was determined using realized prices at March 22, 2002. Had year-end 2001 realized prices been used, the write-down would have been $71.3 million.

13. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees of the Company. The Company did not contribute to the plan in 2001 or 2002. The employee contribution limitations are determined by formulas, which limit the upper one-third of the plan members from contributing amounts that would cause the plan to be top-heavy. The employee contribution is limited to the lesser of 20% of the employee's annual compensation or $11,000.

14. Guarantor Condensed Consolidation Financial Statements

The following table presents condensed consolidating balance sheets of Abraxas, as a parent company, and its significant subsidiaries, Canadian Abraxas and Old Grey Wolf, as of December 31, 2001 and 2002 and the related consolidating statements of operations and cash flows for the years ended December 31, 2000, 2001 and 2002. Canadian Abraxas is a guarantor of the First Lien Notes ($63.5 million) and jointly and severally liable with Abraxas for the Second Lien Notes ($190.2 million) and the Old Notes ($801,000). Old Grey Wolf is a non-guarantor with respect to the First Lien Notes and the Old Notes. The following condensed financial statements have been restated - see Note 20.

Condensed Consolidating Parent Company, Restricted Subsidiaries and Non-Guarantor
December 31, 2002
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	
Assets:				
Current assets:				
Cash	$ 557	$ 2,188	$ 2,137	$
Accounts receivable, less allowance for doubtful accounts......................	4,482	4,782	11,938	
Equipment inventory	860	142	12	
Other current assets	316	682	242	
Total current assets..............	6,215	7,794	14,329	
Property and equipment - net................	74,435	38,858	37,101	
Deferred financing fees, net	2,970	688	2,013	
Deferred income taxes and other assets	108,558		7,820	
Total assets	$ 192,178	$ 47,340	$ 61,263	$

Liabilities and Stockholders' deficit:				
Current liabilities:				
Accounts payable	$ 15,928	$ 766	$ 6,398	$
Accrued interest	5,000	1,009	-	
Other accrued expenses	1,162	-	-	
Current maturities of long-term debt	63,500	-	-	
Total current liabilities..................	85,590	1,775	6,398	
Long-term debt	138,350	52,629	45,964	
Future site restoration	-	3,171	775	
	223,940	57,575	53,137	
Stockholders' equity (deficit)..................	(31,762)	(10,235)	8,126	
Total liabilities and stockholders' equity (deficit).......................................	$ 192,178	$ 47,340	$ 61,263	$

(1) Includes amounts for insignificant U.S. subsidiaries, Sandia and Wamsutter, which are guarantors of the First and Second Lien Notes. Sandia is also a guarantor of the Old Notes. Additionally, these subsidiaries are designated as Restricted Subsidiaries along with Canadian Abraxas.

Condensed Consolidating Parent Company, Restricted Subsidiaries and Non-Guarantor

December 31, 2001

(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	
Assets:				
Current assets:				
Cash	$ 3,593	$ 1,245	$ 2,767	$
Accounts receivable, less allowance for doubtful accounts.....................	17,184	792	6,782	
Equipment inventory	1,061	178	12	
Other current assets	250	99	94	
Total current assets..................	22,088	2,314	9,655	
Property and equipment - net................	116,462	122,486	42,946	
Deferred financing fees - net	2,779	1,042	107	
Other assets	108,801	784	6,281	
Total assets	$ 250,130	$ 126,626	$ 58,989	$

Liabilities and Stockholders' deficit:

Current liabilities:

Accounts payable	$ 10,642	$ 17,009	$ 9,472 $
Accrued interest	5,000	1,009	4
Other accrued expenses	1,052	-	64
Hedge liability	438	220	-
Current maturities of long-term debt	415	-	-
Total current liabilities	17,547	18,238	9,540
Long-term debt	209,611	52,629	22,944
Deferred income taxes	-	17,718	2,903
Future site restoration	-	3,399	657
	227,158	91,984	36,044
Stockholders' equity (deficit)	22,972	34,642	22,945
Total liabilities and stockholders' equity (deficit)	$ 250,130	$ 126,626	$ 58,989

Condensed Consolidating Parent Company, Restricted Subsidiary and Non-Guarantor Statem
For the year ended December 31, 2002
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)
Revenues:			
Oil and gas production revenues	$ 20,835	$ 14,726	$15,301 $
Gas processing revenues	-	1,955	465
Rig revenues	635	-	-
Other	71	152	180
	21,541	16,833	15,946
Operating costs and expenses:			
Lease operating and production taxes	7,639	3,751	3,850
Depreciation, depletion, and amortization	9,194	10,633	6,712
Proved property impairment	28,178	60,501	27,314
Rig operations	567	-	-
General and administrative	4,045	1,312	1,527
	49,623	76,197	39,403
Operating income (loss)	(28,082)	(59,364)	(23,457)
Other (income) expense:			
Interest income	(92)	-	-
Amortization of deferred financing fees	1,325	366	404
Interest expense	24,689	6,665	2,796
Other	1,168	-	-

	27,090	7,031	3,200
Income (loss) before income tax	(55,172)	(66,395)	(26,657)
Income tax expense (benefit).....................	-	(18,522)	(11,175)
Net income (loss)................................	$ (55,172)	$ (47,873)	$(15,482) $

Condensed Consolidating Parent Company, Restricted Subsidiary and Non-Guarantor Statem
For the year ended December 31, 2001
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)
Revenues:			
Oil and gas production revenues	$ 34,934	$ 24,308	$ 13,959
Gas processing revenues	-	2,008	430
Rig revenues	756	-	-
Other	85	471	292
	35,775	26,787	14,681
Operating costs and expenses:			
Lease operating and production taxes	9,302	6,836	2,478
Depreciation, depletion, and amortization	12,336	14,707	5,441
Proved property impairment....................	-	2,638	-
Rig operations	702	-	-
General and administrative	3,742	1,720	983
General and administrative (Stock-based Compensation)..............................	(2,767)	-	-
	23,315	25,901	8,902
Operating income (loss)..........................	12,460	886	5,779

Other (income) expense:			
Interest income	(1,242)	-	-
Amortization of deferred financing fees........	1,907	361	-
Interest expense..............................	25,086	7,117	484
Other	1,052	-	-
	26,803	7,478	484
Income (loss) before income tax	(14,343)	(6,592)	5,295
Income tax expense (benefit).....................	505	(80)	1,977
Minority interest in income of consolidated foreign subsidiary............................	-	-	1,676
Net income (loss)................................	$ (14,848)	$ (6,512)	$ 1,642 $

Condensed Consolidating Parent Company, Restricted Subsidiary and Non-Guarantor Stat
For the year ended December 31, 2000
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)
Revenues:			
Oil and gas production revenues	$ 32,165	$ 27,425	$ 13,383
Gas processing revenues.......................	-	2,271	446
Rig revenues	505	-	-
Other	216	170	19
	32,886	29,866	13,848
Operating costs and expenses:			
Lease operating and production taxes	7,755	8,695	2,333
Depreciation, depletion, and amortization	12,328	18,126	5,403
Rig operations	717	-	-
General and administrative	4,115	1,484	934
General and administrative (Stock-based Compensation).............................	2,767	-	-
	27,682	28,305	8,670
Operating income (loss).........................	5,204	1,561	5,178
Other (income) expense:			
Interest income	(2,277)		-
Amortization of deferred financing fees........	1,660	431	-
Interest expense	24,594	7,582	711
Gain on sale of equity investment	(33,983)	-	-
Gain on debt extinguishment..................	(1,773)	-	-
Other	1,116	447	-
	(10,663)	8,460	711
Income (loss) before income tax	15,867	(6,899)	4,467
Income tax expense (benefit).....................	3,433	(1,658)	1,930
Minority interest in income of consolidated foreign subsidiary............................	-	-	1,281
Net income (loss)...............................	$ 12,434	$ (5,241)	$ 1,256

Condensed Consolidating Parent, Restricted Subsidiary and Non-Guarantor Statemen
For the year ended December 31, 2002
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)
Operating Activities			
Net income (loss)	$ (55,172)	$ (47,873)	$(15,482) $
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	9,194	10,633	6,712
Proved property impairment	28,178	60,501	27,314
Deferred income tax (benefit) expense...	-	(18,522)	(11,175)
Amortization of deferred financing fees.	1,325	366	404
Changes in operating assets and liabilities:			
Accounts receivable	18,088	(3,187)	1,114
Equipment inventory	201	-	-
Other	381	(177)	(78)
Accounts payables and accrued expenses	(47)	479	(3,251)
Net cash provided by (used in)operations.....	2,148	2,220	5,558
Investing Activities			
Capital expenditures, including purchases and development of properties	(5,070)	(4,926)	(28,916)
Proceeds from sale of oil and gas properties................................	9,725	21,789	2,362
Net cash provided (used) by investing activities................................	4,655	16,863	(26,554)
Financing Activities			
Proceeds from long-term borrowings...........	-	-	20,551
Payments on long-term borrowings	(8,176)	(18,262)	-
Deferred financing fees......................	(1,663)	146	(22)
Net cash provided (used) by financing activities................................	(9,839)	(18,116)	20,529
Effect of exchange rate changes on cash	-	(24)	(163)
Increase (decrease) in cash	(3,036)	943	(630)
Cash at beginning of year	3,593	1,245	2,767
Cash at end of year.........................	$ 557	$ 2,188	$ 2,137 $

Condensed Consolidating Parent, Restricted Subsidiary and Non-Guarantor Statemen

For the year ended December 31, 2001
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)
Operating Activities			
Net income (loss)	$ (14,848)	$ (6,512)	$ 1,642
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Minority interest in income of foreign subsidiary...........................	-	-	1,676
Loss on sale of equity investment.......	845	-	-
Depreciation, depletion, and amortization	12,336	14,707	5,441
Proved property impairment.............	-	2,638	-
Deferred income tax (benefit) expense...	-	(80)	1,977
Amortization of deferred financing fees.	1,907	361	-
Stock-based compensation	(2,767)	-	-
Changes in operating assets and liabilities:			
Accounts receivable	28,804	(9,721)	(6,390)
Equipment inventory	(76)	-	-
Other	(281)	-	175
Accounts payables and accrued expenses	(12,915)	(2,254)	(402)
Net cash provided (used) by operating activities	13,005	(861)	4,119
Investing Activities			
Capital expenditures, including purchases and development of properties	(19,126)	(15,313)	(22,617)
Proceeds from sale of oil and gas properties...............................	9,677	15,882	3,379
Acquisition of minority interest	(2,679)	-	-
Net cash provided (used) by investing activities...............................	(12,128)	569	(19,238)
Financing Activities			
Proceeds form issuance of common stock.......	16	-	-
Proceeds from long-term borrowings	11,700	-	18,295
Payments on long-term borrowings	(9,326)	-	-
Net cash provided (used) by financing activities...............................	2,390	-	18,295
	3,267	(292)	3,176
Effect of exchange rate changes on cash	-	(141)	(409)
Increase (decrease) in cash	3,267	(433)	2,767
Cash at beginning of year	326	1,678	-

Cash at end of year	$ 3,593	$ 1,245	$ 2,767 $

Condensed Consolidating Parent, Restricted Subsidiary and Non-Guarantor Statement
For the year ended December 31, 2000
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)
Operating Activities			
Net income (loss)	$ 12,434	$ (5,241)	$ 1,256
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Minority interest in income of foreign subsidiary	-	-	1,281
Gain on extinguishment of debt	(1,773)	-	-
Gain on sale of equity investment	(33,983)	-	-
Depreciation, depletion, and amortization	12,329	18,126	5,402
Deferred income tax expense (benefit)	3,433	(153)	1,658
Amortization of deferred financing fees	1,660	431	-
Stock-based compensation	2,767	-	-

Issuance of common stock and warrants for compensation	265	-	-
Changes in operating assets and liabilities:			
Accounts receivable	8	(3,461)	(3,583)
Equipment inventory	(538)	-	-
Other	(184)	(1,618)	(37)
Accounts payables and accrued expenses	5,357	378	5,158
Net cash provided (used) by operations	1,775	8,462	11,135
Investing Activities			
Capital expenditures, including purchases and development of properties	(39,767)	(15,649)	(18,996)
Proceeds from sale of oil and gas properties	5,542	7,393	8,222
Proceeds from sale of equity investment	34,482	-	-
Net cash provided (used) by investing activities	257	(8,256)	(10,774)
Financing Activities			
Purchase of treasury stock, net	(78)	-	-

Proceeds from long-term borrowings	6,400	-	-	
Payments on long-term borrowings	(9,979)	-	(184)	
Deferred financing fees	23	-	-	
Net cash provided (used) by financing activities	(3,634)	-	(184)	
	(1,602)	206	177	
Effect of exchange rate changes on cash	-	(399)	(177)	
Increase (decrease) in cash	(1,602)	(193)	-	
Cash at beginning of year	1,928	1,871	-	
Cash at end of year........................	$ 326	$1,678	$ -	$

15. Business Segments

The Company conducts its operations through two geographic segments, the United States and Canada, and is engaged in the acquisition, development, and production of crude oil and natural gas and the processing of natural gas in each country. The Company's significant operations are located in the Texas Gulf Coast, the Permian Basin of western Texas, and Canada. Identifiable assets are those assets used in the operations of the segment. Corporate assets consist primarily of deferred financing fees and other property and equipment. The Company's revenues are derived primarily from the sale of crude oil, condensate, natural gas liquids, and natural gas to marketers and refiners and from processing fees from the custom processing of natural gas. As a general policy, collateral is not required for receivables; however, the credit of the Company's customers is regularly assessed. The Company is not aware of any significant credit risk relating to its customers and has not experienced significant credit losses associated with such receivables.

In 2002, four customers accounted for approximately 79% of consolidated oil and natural gas production revenue. Three customers accounted for approximately 77% of United States revenue and one customer accounted for approximately 80% of revenue in Canada. In 2001, three customers accounted for approximately 41% of oil and natural gas production revenues. Three customers accounted for approximately 76% of United States revenue and five customers accounted for approximately 76% of revenue in Canada. In 2000, two customers accounted for approximately 26% of oil and natural gas production revenues and gas processing revenues.

Business segment information about the Company's 2000 operations in different geographic areas is as follows:

	U.S.	Canada	Tot
		(In thousands)	
Revenues	$ 32,886	$ 43,714	$
Operating profit	$ 12,446	$ 6,739	$
General corporate			

Net interest expense and amortization of deferred financing fees			
Other income (net)..........................			
Income before income taxes			$
Identifiable assets at December 31, 2000 ...	$ 132,327	$ 197,229	$
Corporate assets			
Total assets			$

Business segment information about the Company's 2001 operations in different geographic areas is as follows:

	U.S.	Canada	Tot
		(In thousands)	
Revenues	$ 35,775	$ 41,468	$
Operating profit...........................	$ 13,795	$ 6,665	$
General corporate			
Net interest expense and amortization of deferred financing fees			
Other expense..............................			
Loss before income taxes................			$
Identifiable assets at December 31, 2001 ...	$ 124,993	$ 174,063	$
Corporate assets			
Total assets			$

Business segment information about the Company's 2002 operations in different geographic areas is as follows:

	U.S.	Canada	Tot
		(In thousands)	
Revenues	$ 21,541	$ 32,779	$
Operating loss.............................	$ (23,677)	$ (82,821)	$ (
General corporate			
Net interest expense and amortization of			

deferred financing fees			
Other expense.............................			
Loss before income taxes................			$ (
Identifiable assets at December 31, 2002....	$ 81,025	$ 94,059	$
Corporate assets			
Total assets			$

16. Hedging Program and Derivatives

On January 1, 2001, the Company adopted SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" as amended and interpreted. Under SFAS 133,

all derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, the Company uses only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in Other Comprehensive Income (Loss), a component of Stockholders' Equity, to the extent that the hedge is effective.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in accumulated Other Comprehensive Income (Loss) related to a cash flow hedge that becomes ineffective remain unchanged until the related production is delivered. If the Company determines that it is probable that a hedged transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Gains and losses on hedging instruments related to accumulated Other Comprehensive Income (Loss) and adjustments to carrying amounts on hedged production are included in natural gas or crude oil production revenue in the period that the related production is delivered.

On January 1, 2001, in accordance with the transition provisions of SFAS 133, the Company recorded $31.0 million, net of tax, in Other Comprehensive Income (Loss) representing the cumulative effect of an accounting change to recognize the fair value of cash flow derivatives. The Company recorded cash flow hedge derivative liabilities of $38.2 million on that date and a deferred tax asset of $7.2 million.

For the year ended December 31, 2001, losses before tax of $12.1 million were transferred from Other Comprehensive Income (Loss) to revenue and the fair value of outstanding liabilities decreased by $25.5 million. The ineffective portion of the cash flow hedges was not material at December 31, 2001.

For the year ended December 31, 2001, $566,000 of deferred net loss on

derivative instruments were recorded in Other Comprehensive Income (Loss). All of the deferred net loss was reclassified to earnings during the next twelve-month period.

All hedge transactions are subject to the Company's risk management policy, approved by the Board of Directors. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, the Company assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

The Company entered into a costless collar hedge agreement with Barrett Resources Corporation ("Barrett") for the period November 1999 through October 2000. This agreement consisted of a swap for 1,000 Bbls per day of crude oil with the Company being paid $20.30 and paying NYMEX calendar month average, and an additional 1,000 Bbls of crude oil per day with a floor price of $18.00 per Bbl and a ceiling of $22.00 per Bbl. The Company realized a loss from hedges of $20.2 million for the year ended December 31, 2000, which is accounted for in Oil and Gas Production Revenue. At year end 2001 Barrett had a swap call on either 1,000 Bbls of crude oil or 20,000 MMBtu of natural gas per day at Barrett's option at fixed prices ($18.90 for crude oil or $2.60 to $2.95 for natural gas) through October 31, 2002. The Company realized a loss from hedges of $12.1 million and $3.2 million for the years ended December 31, 2001 and 2002 respectively, which is accounted for in Oil and Gas Production Revenue.

Under the terms of the New Senior Secured Credit Agreement, (see Note 2) the Company is required to maintain hedging agreements with respect to not less than 25% nor more than 75% of it crude oil and natural gas production for a rolling six month period. As of January 23, 2003, the Company has entered into a collar option agreement with respect to 5,000 MMBtu per day, or approximately 25% of the Company's production, at a call price of $6.25 per MMBtu and a put price of $4.00 per MMBtu, for the calendar months of February through July 2003. In February 2003 the Company entered into an additional hedge agreement for 5,000 MMbtu per day with a floor of $4.50 per MMBtu for the calendar months of March 2003 through February 2004.

17. Comprehensive Income

Comprehensive income includes net income, losses and certain items recorded directly to Stockholders' Equity and classified as Other Comprehensive Income (Loss). The following table illustrates the calculation of comprehensive income for the year ended December 31, 2002:

	Comprehensive Income (Loss)	Co
	For the year Ended December 31, 2002	
Accumulated other comprehensive loss at December 31, 2001		

Net loss	$ (118,527)
Other Comprehensive income (loss):	
Hedging derivatives (net of tax) - See Note 16	
Reclassification adjustment for settled hedge contracts, net of taxes of ($596)	2,556
Change in fair market value of outstanding hedge positions net of taxes of $504	(1,990)
	566
Foreign currency translation adjustment	4,292
Other comprehensive income (loss)	4,858
Comprehensive income (loss)	$ (113,669)
Accumulated other comprehensive loss at December 31, 2002	

18. Proved Property Impairment

In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the year, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the Company's financial statements. As of December 31, 2001, the Company's net capitalized costs of oil and gas properties exceeded the present value of its estimated proved reserves by $71.3 million ($38.9 million on the U.S. properties and $32.4 million on the Canadian properties). These amounts were calculated considering 2001 year-end prices of $19.84 per barrel for oil and $2.57 per Mcf for gas as adjusted to reflect the expected realized prices for each of the full cost pools. The Company did not adjust its capitalized costs for its U.S. properties because subsequent to December 31, 2001, oil and gas prices increased such that capitalized costs for its U.S. properties did not exceed the present value of the estimated proved oil and gas reserves for its U.S. properties as determined using increased realized prices on March 22, 2002 of $24.16 per Bbl for oil and $2.89 per Mcf for gas. During the second quarter of 2002, the Company had a ceiling limitation write-down of $116.0 million.

19. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying table presents information concerning the Company's crude oil and natural gas producing activities as required by Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows:

	Years Ended December 31			
	2001			
	Total	U.S.	Canada	Total
				(In thousands)

Proved crude oil and natural gas properties	$ 486,098	$ 284,182	$ 201,916	$ 521,30
Unproved properties	10,626	-	10,626	7,05
Total	496,724	284,182	212,542	528,36
Accumulated depreciation, depletion, and amortization, and impairment	(280,280)	(168,124)	(112,156)	(420,34
Net capitalized costs ...	$ 216,444	$ 116,058	$ 100,386	$ 108,01

Cost incurred in oil and gas property acquisitions, exploration and development activities are as follows:

	Years					
	2000			2001		
	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)					
Property acquisition costs:						
Proved	$ 7,189	$ -	$ 7,189	$ -	$ -	$ -
Unproved	-	-	-	-	-	-
	$ 7,189	$ -	$ 7,189	$ -	$ -	$ -
Property development and exploration costs	$ 64,873	$ 39,631	$ 25,242	$ 56,694	$ 18,867	$ 37,827

(1) Canadian costs in 2002 were primarily for exploratory purposes.

The results of operations for oil and gas producing activities are as follows:

Years Ended December 31					
2000			2001		
Total	U.S.	Canada	Total	U.S.	Canada

				(In thousands)		
Revenues	$ 72,973	$ 32,165	$ 40,808	$ 73,201	$ 34,934	$ 38,26
Production costs	(18,783)	(7,755)	(11,028)	(18,616)	(9,302)	(9,31
Depreciation, depletion, and amortization	(35,497)	(11,968)	(23,529)	(32,124)	(11,976)	(20,14
Proved property impairment .	-	-	-	(2,638)	-	(2,63
General and administrative .	(1,722)	(1,118)	(604)	(1,565)	(1,073)	(49
Income taxes (expense) benefit..................	(339)	-	(339)	(2,419)	-	(2,41
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 16,632	$ 11,324	$ 5,308	$ 15,839	$ 12,583	$ 3,25
Depletion rate per barrel of oil equivalent, before impact of impairment	$ 8.30	$ 6.19	$ 10.02	$ 8.81	$ 6.96	$ 10.

Estimated Quantities of Proved Oil and Gas Reserves

The following table presents the Company's estimate of its net proved crude oil and natural gas reserves as of December 31, 2000, 2001, and 2002. The Company's management emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been prepared by independent petroleum reserve engineers.

	Total		United States	
	Liquid Hydrocarbons	Natural Gas	Liquid Hydrocarbons	Natural Gas
	(Barrels)	(Mcf)	(Barrels)	(Mcf)
				(In Thousand
Proved developed and undeveloped reserves:				
Balance at January 1, 2000 (1)	9,849	164,305	6,421	80,417
Revisions of previous estimates	(216)	(21,342)	54	(13,441)
Extensions and discoveries	791	72,498	315	57,371
Purchase of minerals in place	254	6,822	-	-
Production	(952)	(19,963)	(539)	(8,364)
Sale of minerals in place	(882)	(10,993)	(170)	(1,075)
Balance at December 31, 2000.............	8,844	191,327	6,081	114,908
Revisions of previous estimates	(628)	2,944	(688)	3,318
Extensions and discoveries	1,064	26,329	354	4,886
Production	(732)	(17,495)	(416)	(7,823)
Sale of minerals in place	(1,746)	(14,348)	(924)	(6,821)

Balance at December 31, 2001	6,802	188,757	4,407	108,468
Revisions of previous estimates	(798)	(29,701)	(63)	(15,248)
Extensions and discoveries	522	19,166	-	-
Production	(534)	(15,453)	(264)	(5,472)
Sale of minerals in place	(1,387)	(23,937)	(843)	(9,553)
Balance at December 31, 2002 (2)	4,605	138,832	3,237	78,195

(1) The beginning of year 2000 amounts exclude the Company's proportion interest in Partnership proved reserves, accounted for by the equity method, of 2.8 Mbbls of liquid hydrocarbons and 25.8 MMcf of natural gas.

(2) Includes 1,146 Bbl of liquid hydrocarbons and 47,066 Mcf of natural gas applicable to Canadian Abraxas and Old Grey Wolf that were sold in January 2003.

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Estimated Quantities of Proved Oil and Gas Reserves (continued)

	Liquid Hydrocarbons	Natural Gas	Liquid Hydrocarbons	Natural Gas
	(Barrels)	(Mcf)	(Barrels)	(Mcf)
				(In Thousand
Proved developed reserves:				
December 31, 2000	7,001	119,737	4,609	48,177
December 31, 2001	5,047	111,243	2,892	40,514
December 31, 2002	3,004	90,374	1,754	34,776

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following disclosures concerning the standardized measure of future cash flows from proved crude oil and natural gas are presented in accordance with SFAS No. 69. The standardized measure does not purport to represent the fair market value of the Company's proved crude oil and natural gas reserves. An estimate of fair market value would also take into account, among other factors,

the recovery of reserves not classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Under the standardized measure, future cash inflows were estimated by applying period-end prices at December 31, 2002 adjusted for fixed and determinable escalations, to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis of the properties. Operating loss carryforwards, tax credits, and permanent differences to the extent estimated to be available in the future were also considered in the future income tax calculations, thereby reducing the expected tax expense.

Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Set forth below is the Standardized Measure relating to proved oil and gas reserves for:

	Years Ende					
	2000			2001		
	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)					
Future cash inflows	$ 2,046,039	$ 1,274,871	$ 771,168	$ 607,375	$ 313,640	$ 293,735
Future production and development costs	(318,130)	(254,667)	(63,463)	(220,613)	(138,296)	(82,317
Future income tax expense .	(230,987)	(65,421)	(165,566)	-	-	-
Future net cash flows	1,496,922	954,783	542,139	386,762	175,344	211,418
Discount	(721,388)	(468,663)	(252,725)	(177,096)	(98,157)	(78,939
Standardized Measure of discounted future net cash relating to proved reserves	$ 775,534	$ 486,120	$ 289,414	$ 209,666	$ 77,187	$ 132,479

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is an analysis of the changes in the Standardized Measure:

	Year Ended December 31		
	2000	2001	200
	(In thousands)		
Standardized Measure, beginning			
of year	$ 238,451	$ 775,534	$
Sales and transfers of oil and gas produced, net of production costs	(54,190)	(54,585)	
Net changes in prices and development and production costs from prior year	707,755	(613,325)	
Extensions, discoveries, and improved recovery, less related costs	290,283	39,982	
Purchases of minerals in place	33,586	-	
Sales of minerals in place	(75,391)	(96,096)	
Revision of previous quantity estimates ...	(95,757)	(2,474)	
Change in future income tax expense	(224,668)	230,987	
Other	(68,380)	(147,910)	
Accretion of discount	23,845	77,553	
Standardized Measure, end of year	$ 775,534	$ 209,666	$

20. Restatement

In January 2003, the Company sold its wholly owned Canadian subsidiaries, Old Grey Wolf and Canadian Abraxas as part of a series of transactions related to a financial restructuring - see Note 2 for additional information regarding an exchange offer, redemption of certain notes and a new credit agreement. Subsequent to the issuance of its consolidated financial statements for the year ended December 31, 2002, the Company's management determined that the wholly owned Canadian subsidiaries should not have been presented as discontinued operations. As a result, the accompanying consolidated balance sheets as of December 31, 2002 and 2001, and the related consolidated statements of operations, and cash flows for each of the three years in the period ended December 31, 2002 have been restated to present the assets and liabilities, results of operations, and cash flows as components of continuing operations.

A summary of the significant effects of the restatement is as follows (In thousands):

	For the year ended Dec		
	2000		2001
	As Previously	As	As Previously

	Reported	Restated	Reported	Res
Revenues:				
Oil and gas production revenue	$ 32,165	$ 72,973	$ 34,934	$ 7
Gas processing revenue	-	2,717	-	
Rig revenue	505	505	756	
Other	216	405	85	
	32,886	76,600	35,775	7
Operating costs and expenses:				
Lease operating and production taxes	7,755	18,783	9,302	1
Depreciation, depletion and amortization	12,328	35,857	12,336	3
Proved property impairment	-	-	-	
Rig operations	717	717	702	
General and administrative	4,840	6,533	4,937	
General and administrative (Stock-based compensation)	2,767	2,767	(2,767)	(
	28,407	64,657	24,510	5
Operating income (loss)	4,479	11,943	11,265	1
Other (income) expense:				
Interest income	(530)	(530)	(78)	
Amortization of deferred financing fees	1,660	2,091	1,907	
Interest expense	22,847	31,140	23,922	3
Financing costs	-	-	-	
(Gain) loss on sale of equity investment	(33,983)	(33,983)	845	
Gain on debt extinguishment (1)	-	(1,773)	-	
Other	(b) 1,116	1,563	207	
	(8,890)	(1,492)	26,803	3
Income (loss) before income tax	13,369	13,435	(15,538)	(1
Income tax expense (benefit):				
Current	-	(1,233)	505	
Deferred	3,433	4,938	-	
Minority interest in income of consolidated foreign subsidiary	-	1,281	-	
Loss from discontinued operations	(3,260)	-	(3,675)	
Extraordinary item: gain on debt extinguishment (1)	1,773	-	-	
Net income (loss)	$ 8,449	$ 8,449	$ (19,718)	$ (1

(1) As required by SFAS No. 145, the Company has reclassified the gain on the early extinguishment of debt in 2000 originally reported as an extraordinary item to other income. See Note 1.

	December 31	
	2001	
	As Previously Reported	As Restated
Current Assets:		
Cash	$ 3,593	$ 7,605
Accounts receivable:		
Joint owners	938	2,785
Oil and gas production sales	2,988	4,758
Other	135	504
	4,061	8,047
Equipment inventory	1,061	1,251
Other current assets	250	443
	8,965	17,346
Assets held for sale	163,902	-
Total current assets	172,867	17,346
Property and equipment:		
Oil and gas properties:		
Proved	290,635	486,098
Unproved	4,571	10,626
Other property and equipment	2,587	67,632
Total	297,793	564,356
Less accumulated depreciation, depletion and amortization	170,307	282,462
Total property and equipment - net	127,486	281,894
Deferred financing fees	2,779	3,928
Deferred income taxes	-	-
Other	484	448
Total assets	$ 303,616	$ 303,616
Current Liabilities:		
Accounts payable	$(a) 3,862	$ 10,542
Joint interest oil and gas production payable	1,180	3,596
Accrued interest	5,000	6,013
Other accrued expenses	1,052	1,116
Hedge liability	438	658
Current maturities of long-term debt	415	415
	11,947	22,340
Liabilities related to assets held for sale	57,552	-
Total current liabilities	69,499	22,340
Long-term debt	262,240	285,184
Deferred income taxes	-	20,621
Future site restoration	462	4,056
Stockholders' equity (deficit)	(28,585)	(28,585)
Total liabilities and stockholders' deficit	$ 303,616	$ 303,616

(a) Previously reported as $5,042 due to clerical error. Amount has been corrected.
(b) Previously reported as $1,016 due to clerical error. Amount has been corrected.

FINANCIAL STATEMENTS

GREY WOLF EXPLORATION INC.

December 31, 2002

Deloitte & Touche LLP
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AUDITORS' REPORT

To the Directors of
Grey Wolf Exploration Inc.

We have audited the balance sheets of Grey Wolf Exploration Inc. as at December 31, 2002 and 2001 and the statements of earnings (loss) and retained earnings (deficit) and of cash flows for each of the years in the three year period ended December 31, 2002. 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.

With respect to the financial statements for each of the years in the three-year period ended December 31, 2002, we conducted our audits in accordance with Canadian generally accepted auditing standards and auditing standards generally accepted in the United States of America. Those 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 audits provide a reasonable basis for our opinion.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

On February 23, 2001, we reported separately to the shareholders of the Company on financial statements for the year ended December 31, 2000, prepared in accordance with the Canadian generally accepted accounting principles, which excluded Note 12 on differences between Canadian and United States generally accepted accounting principles.

Calgary, Canada /s/ Deloitte & Touche LLP
March 10, 2003 Chartered Accountants

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COMMENTS BY AUDITORS FOR U.S. READERS ON
CANADA - U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting principles that have been implemented in the financial statements. As discussed in Note 7 to the financial statements, in 2001 the Company changed its method of computing diluted earnings per share to conform to the new Canadian Institute of Chartered Accountants Handbook recommendation section 3500. In addition, as discussed in Note 6 to the financial statements, in 2000 the Company changed its method of accounting for income taxes to conform to the new Canadian Institute of Chartered Accountants Handbook recommendation section 3465.

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining significant subsequent events that have been disclosed in the financial statements. We have not audited any financial statements of the Company for any period subsequent to December 31, 2002. However, as discussed in Note 13, the Company's parent company sold all of the outstanding common shares of the Company on January 23, 2003.

Calgary, Canada /s/ Deloitte & Touche LLP
March 10, 2003 Chartered Accountants

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GREY WOLF EXPLORATION INC.

Balance Sheets
As At December 31
(Thousands of Canadian dollars)

	2002 $
ASSETS	
Current	
Cash (Note 4)	3,365
Accounts receivable (Note 10)	8,230
	11,595
Long-term receivable (Note 10)	10,000
Property and equipment (Note 3)	23,401
Future income taxes (Note 6)	25,233
	70,229
Liabilities	
Current	
Accounts payable and accrued liabilities (Note 10)	10,078
Long-term debt (Note 4)	69,227
Future site restoration and abandonment	1,221
Future income taxes (Note 6)	-
	80,526
CONTINGENCIES (Note 11)	
SHAREHOLDERS' EQUITY (DEFICIENCY)	
Share capital (Note 5)	27,891
Retained earnings (deficit)	(38,188
	(10,297
	70,229

See accompanying notes

GREY WOLF EXPLORATION INC.

Statements of Earnings (Loss) and Retained Earnings (Deficit)
Years Ended December 31
(thousands of Canadian dollars, except for share amounts)

	2002 $	
Revenue		
Petroleum and natural gas sales	33,245	
Royalties, net of Alberta Royalty Tax Credit	(8,237)	
	25,008	
Expenses		
Operating	6,032	
General and administrative (Note 3)	2,367	
Interest and finance charges (Note 10)	4,518	
Depletion, depreciation and site restoration (Note 3)	8,003	
Write down of petroleum and natural gas properties and facilities	82,635	
Amortization of deferred financing fees (Note 4)	634	
	104,189	
Earnings (loss) before taxes	(79,181)	
Provision for (recovery of) taxes (Note 6)		
Current	24	
Future	(31,592)	
	(31,568)	
Net earnings (loss)	(47,613)	
Retained earnings, beginning of year	9,425	
Adoption of income tax accounting standard change (Note 6)	-	
Retained earnings (deficit), end of year	(38,188)	
Basic and diluted earnings (loss) per share (Note 7)	(3.71)	
Weighted average number of shares		
Basic	12,841,327	1
Diluted	12,841,327	1

See accompanying notes

GREY WOLF EXPLORATION INC.

Statements of Cash Flows

Years Ended December 31
(Thousands of Canadian dollars, except for share amounts)

	2002 $
Operating Activities	
Net earnings (loss)	(47,613)
Depletion, depreciation and site restoration	8,003
Write down of petroleum and natural gas properties and facilities	82,635
Future income tax expense (recovery)	(31,592)
Amortization of deferred financing fees	634
Cash flow from operations	12,067
Changes in non-cash working capital items (Note 9)	(3,355)
	8,712
Financing Activities	
Increase in long-term debt	67,994
Repayments of long-term debt	(35,723)
Increase in long-term receivable	-
Issuance of common shares	-
	32,271
Total cash resources provided	40,983
Investing Activities	
Property and equipment received under property swap agreement	-
Disposal of property and equipment under property swap agreement	-
Net cash proceeds	-
Other acquisitions	-
Expenditures for property and equipment	45,558
Dispositions of property and equipment	(3,657)
Site restoration	122
	42,023
Increase (decrease) in cash	(1,040)
Cash, beginning of year	4,405
Cash, end of year	3,365
Basic and diluted cash flow from operations per share (Note 7)	0.94
Cash interest paid	5,483
Cash taxes paid	88

See accompanying notes

GREY WOLF EXPLORATION INC.
Notes to the Financial Statements
Years Ended December 31, 2002, 2001 and 2000

(Tabular amounts in thousands of Canadian dollars, except for share amounts)

1. DESCRIPTION OF BUSINESS

Grey Wolf Exploration Inc. ("Grey Wolf" or "the Company") was incorporated under the laws of the Province of Alberta on December 23, 1986. The Company's primary business is the exploration, development and production of crude oil and natural gas in western Canada. As at December 31, 2002 and 2001 the Company was a wholly-owned subsidiary of Abraxas Petroleum Corporation ("Abraxas").

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Differences between Canadian and U.S. GAAP are outlined in Note 12 to the financial statements.

Cash

Cash includes amounts held in short-term deposits with original maturities of 90 days or less.

Property and equipment

The Company follows the full cost method of accounting in accordance with the guideline issued by the Canadian Institute of Chartered Accountants ("CICA") whereby all costs associated with the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a Canadian cost centre and charged to income as set out below. Such costs include acquisition, drilling, geological and geophysical costs related to exploration and development activities. Costs of acquiring and evaluating unproved properties are excluded from the depletion base until it is determined whether or not proved reserves are attributable to the properties or impairment occurs.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion of petroleum and natural gas properties and depreciation of production equipment, except for gas plants and related facilities, is provided on accumulated costs using the unit-of-production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers. For purposes of the depletion calculation, proven petroleum and natural gas reserves are converted to a common unit of measure on the basis of one barrel of oil or liquids being equal to six thousand cubic feet of natural gas. Depreciation of gas plants and related production facilities is calculated on a straight-line basis over an average 18-year term.

The depletion and depreciation cost base includes capitalized costs, less costs of unproved properties, plus provision for future development costs of proved undeveloped reserves.

2. SIGNIFICANT ACCOUNTING POLICIES (Continued)

Petroleum and natural gas properties (Continued)

The net carrying value of the Company's petroleum and natural gas properties is limited to an ultimate recoverable amount (the "ceiling test"). This amount is the aggregate of estimated future net revenues from proved reserves and the costs of unproved properties, net of impairment allowances, less future estimated production costs, general and administration costs, financing costs, site restoration and abandonment costs, and income taxes. Future net revenues are estimated using period end prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation substantially enacted at the balance sheet date.

Furniture, leasehold improvements, computer hardware, software and office equipment are carried at cost and are depreciated over the estimated useful life of the assets at rates varying between 20 percent and 30 percent, on a declining-balance basis.

Future site restoration and abandonment costs

The estimated cost of future site restoration is based on the current cost and the anticipated method and extent of site restoration in accordance with existing legislation and industry practice. The annual charge is provided for on a unit-of-production basis for all properties except for gas plants for which the annual charge is calculated on a straight-line basis over the estimated remaining life of the plants. Actual site restoration expenditures are charged to the accumulated liability account as incurred.

Use of estimates

The amounts recorded for depletion and depreciation of property and equipment and the provision for site restoration are based on estimates of proved reserves and production rates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to uncertainty and the effect on the financial statements of changes in such estimates could be significant.

2. SIGNIFICANT ACCOUNTING POLICIES (Continued)

Joint operations

Substantially all of the Company's exploration and development activities are conducted jointly with others, and accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

Revenue recognition

Petroleum and natural gas sales are recognized when the commodities are delivered to purchasers.

Future income taxes

Effective January 1, 2000, the Company adopted, on a retroactive basis without restatement of prior periods, the new Canadian Institute of Chartered Accountants ("CICA") accounting recommendation, "Income Taxes". Under this standard, future income tax assets and liabilities are measured based upon temporary differences between the carrying values of assets and liabilities and their tax basis. Income tax expense (recovery) is computed based on the change during the year in the future tax assets and liabilities. Effects of changes in tax laws and tax rates are recognized when substantially enacted. Prior to January 1, 2000, the Company followed the deferral method of accounting for income taxes.

Stock options

Prior to December 31, 2001, the Company had a stock option plan as described in Note 5. No compensation expense was recognized when the stock options were issued. Consideration received on exercise of stock options was credited to share capital.

Per share figures

Basic per share figures are calculated using the weighted average number of common shares outstanding during the year.

Effective January 1, 2001, the Company retroactively adopted, with restatement of prior periods, the new recommendations of CICA Handbook Section 3500. Under the revised standard, diluted per share figures are calculated based on the weighted average number of shares outstanding during the year plus the additional common shares that would have been outstanding if potentially dilutive common shares had been issued using the treasury stock method. Prior to the adoption of the new recommendations, diluted per share amounts were determined using the imputed earnings method.

2. SIGNIFICANT ACCOUNTING POLICIES (Continued)

Comparative figures

Certain of the prior years' comparative figures have been reclassified to conform to the current year's presentation.

3. PROPERTY AND EQUIPMENT

	2002	
	Cost $	Accumulated Depletion and Depreciation $
Petroleum and natural gas properties	120,727	(102,708)
Gas plants and related production facilities	21,641	(16,314)
Other assets	621	(566)

Net property and equipment	142,989	(119,588)

	2001	
	Cost $	Accumulated Depletion and Depreciation $
Petroleum and natural gas properties	89,516	(25,649
Gas plants and related production facilities	11,010	(3,097)
Other assets	597	(498)
Net property and equipment	101,123	(29,244)

For the year ended December 31, 2002, $701,000 of general and administrative expenses were capitalized as part of property and equipment related directly to the Company's exploration and development activities (2001 - $402,000 and 2000 - $380,000).

As a result of the quarterly ceiling test calculation at June 30, 2002, the Company recorded a write-down of its petroleum and natural gas properties and facilities in the amount of $82,635,000 ($49,649,000 net of related tax recovery). The impairment was primarily due to lower gas prices and reserve revisions subsequent to December 31, 2001, and higher future estimated interest costs relating to the Mirant Facility (Note 4).

3. PROPERTY AND EQUIPMENT (Continued)

Undeveloped property costs of $4,961,511 were excluded from the depletion base for the year ended December 31, 2002 (2001 - $6,065,907 and 2000 - $6,441,705).

Future site restoration and abandonment charges of $294,029 are included in depletion, depreciation and site restoration expense for the year ended December 31, 2002 (2001 - $197,987 and 2000 - $210,486).

4. LONG-TERM DEBT

Long-term debt is comprised of the following:

	2002 $	2001 $
Mirant Facility	72,398	40,127
Revolving term credit facility	-	5,000
Cash held in trust	-	(5,000)
Unamortized deferred financing charges	(3,171)	(3,771)
	69,227	36,356

At December 31, 2002 and 2001, the Company had a credit facility with Mirant Canada Energy Capital Ltd., (the "Mirant Facility") with a maximum available limit of $150,000,000. At December 31, 2002, $72,398,000 was

drawn on this facility (2001 - $40,127,000). Of the $72,398,000 drawn, $10,000,000 was advanced to Canaxas (2001 - $10,000,000) (Note 10). The Company is required to pay an amount equal to monthly net cash flow from operations less interest payments, general and administrative expenses and approved capital expenditures. Loan advances are supported by a first charge demand debenture in the amount of $200,000,000 together with a debenture pledge agreement providing a first priority lien on all the assets of the Company.

Under the Mirant Facility, loan advances bear interest at 9.5%, plus a 5% overriding royalty which will decrease to 2.5% when certain conditions are met. The overriding royalty granted to Mirant was treated as a disposition of petroleum and natural gas properties in the amount of $3,600,000, with a corresponding deferred financing charge recorded of $3,600,000, based on the fair value at the date of disposition. This deferred charge plus additional fees paid in 2001 and 2002 to secure the facility have been netted against the outstanding loan balance and are being amortized over a 6-year period ending in 2007.

4. LONG-TERM DEBT (Continued)

The Mirant Facility was used to extinguish the previous revolving term credit facility. As at December 31, 2001, all of the previous revolving term credit facility had been repaid except for a banker's acceptance for $5,000,000. As at December 31, 2001, equivalent cash had been placed in trust to cover the $5,000,000 repayment, and accordingly was netted against the loan for financial statement purposes. The remaining $5,000,000 was repaid in January 2002.

At December 31, 2000, the Company had a revolving term credit facility with a Canadian chartered bank with a maximum limit of $20,000,000. At December 31, 2000, $11,792,690 was drawn down against this facility. Under the facility, loan advances bore interest at bank prime plus 1/8%, or the then current bankers' acceptances rate plus 1 1/8%. Loan advances were supported by a first floating charge demand debenture in the amount of $25,000,000 covering all the assets of the Company. During May 2001, the maximum limit under the revolving term credit facility was increased to $27,000,000 and remained at this level until replaced by the Mirant Facility in December 2001.

Effective January 1, 2002, the Emerging Issues Committee of the CICA issued Abstract No. 122, which requires callable debt obligations to be presented with current liabilities on the balance sheet. The maximum available amount under the Mirant Facility may be terminated or reduced below the outstanding amount only upon certain unanticipated events of default, and therefore is not classified as a callable debt obligation. In addition, it is anticipated the Company will be a net borrower due to a number of planned capital projects over the next several years. Accordingly, the outstanding balance has been classified as a long-term liability on the balance sheet. The facility matures in December 2007.

Interest and financing charges for the year ended December 31, 2002 includes $5,483,000 of interest expense relating to long-term debt (2001 - $843,000 and 2000 - $1,126,000).

5. SHARE CAPITAL

Authorized

Unlimited number of common shares without nominal or par value.

Issued

	Number of Shares
Balance, January 1, 2000	12,659,741
Exercise of stock options	1,800
Balance, December 31, 2000	12,661,541
Exercise of stock options	179,786
Balance, December 31, 2001 and 2002	12,841,327

Stock options

Prior to December 31, 2001, a maximum of 1,270,000 options to purchase common shares were authorized for issuance under the Company's stock option plan. The options were exercisable on a cumulative basis at 25% per year commencing one year after the grant date and expiring in five years from the date of grant. During the year ended December 31, 2001, all options outstanding in the Company were cancelled and new options were issued by Abraxas.

	Number of Options	We
Balance, January 1, 2000	1,033,715	
Issued	398,376	
Exercised	(1,800)	
Cancelled	(420,262)	
Balance, December 31, 2000	1,010,029	
Exercised	(179,786)	
Cancelled	(830,243)	
Balance December 31, 2001 and 2002	-	

6. PROVISION FOR TAXES

Effective January 1, 2000, the Company accounts for future income taxes using the liability method. Prior to January 1, 2000, the Company followed the deferral method of accounting for income taxes.

Upon adoption of the new accounting recommendation of the CICA effective January 1, 2000, the Company recorded a future income tax liability of $562,000 and decreased the Company's retained earnings by $562,000. Had the new method not been adopted, 2000 net earnings would have been increased by $88,000.

The total provision for taxes recorded differs from the tax calculated by applying the combined statutory Canadian corporate and provincial income tax rates as follows:

	2002 $	2001 $
Calculated income tax (recovery) expense at 42.12% (2001 - 42.62% and 2000 - 44.62%)	(33,351)	3,128
Increase (decrease) in tax resulting from:		
Non-deductible crown royalties and other charges	2,511	2,950
Resource allowance and related items	(583)	(2,757)
Alberta Royalty Tax Credit	(105)	(177)
Large Corporation Tax	24	144
Tax rate adjustment	(62)	(151)
Other	(2)	68
Provision for (recovery of) taxes	(31,568)	3,205

The major components of future income tax asset (liability) at December 31, 2002 and 2001 are as follows:

	2002 $	2001 $
Property and equipment	25,522	(7,672)
Future site restoration	514	447
Share issue costs	19	117
Attributed royalty income carried forward	607	511
Resource allowance	(1,357)	310
Deferred financing costs	(72)	(72)
	25,233	(6,359)

No valuation allowance has been recorded with respect to the future income tax asset balance at December 31, 2002 based on management's assessment that the amount is more likely than not to be realized.

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7. PER SHARE figures

The treasury method of calculating per share figures was adopted

retroactively effective January 1, 2001, with restatement of prior periods.

If the imputed earnings method was utilized for the year ended December 31, 2000, diluted net earnings per share would have been $0.31 per share and diluted cash flow from operations per share would have been $1.11. There was no impact on 2001 diluted per share figures as a result of adopting the new treasury method.

8. FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of accounts receivable, long-term receivable, accounts payable and accrued liabilities, and long-term debt. As at December 31, 2002 and 2001, there were no significant differences between the carrying amounts of these financial instruments reported on the balance sheets and their estimated fair values.

Credit risk

The majority of the Company's accounts receivable are in respect of oil and gas operations. The Company generally extends unsecured credit to these customers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not previously experienced any material credit loss in the collection of receivables.

Interest rate risk

The Company's long-term debt bears interest at a floating market rate plus 1/8%. Accordingly, the Company is subject to interest rate risk, as the required cash flow to service the debt will fluctuate as a result of changes in market rates.

Commodity price risk

The nature of the Company's operations results in exposure to fluctuations in commodity prices. The Company from time to time employs financial instruments to manage its exposure to commodity prices. These instruments are not used for speculative trading purposes. Gains and losses on commodity price hedges are included in revenues upon the sale of the related production. The Company had not entered into any contracts as at December 31, 2002 and 2001.

9. SUPPLEMENTARY CASH FLOW INFORMATION

	2002 $	2001 $
Accounts receivable	1,750	(165)
Accounts payable and accrued liabilities	(5,105)	(581)
Changes in non-cash working capital items	(3,355)	(746)

10. RELATED PARTY TRANSACTIONS

The Company manages the assets and operations of Canadian Abraxas Petroleum Limited ("Canaxas") pursuant to a Management Agreement dated November 12, 1996. Canaxas is a wholly-owned subsidiary of Abraxas. As at December 31, 2002 and 2001, Abraxas owned 97.3% (2000 - 46.0%) of the common shares of the Company and Canaxas owned 2.7% (2000 - 2.7%) of the common shares of the Company. The aggregate common costs of operations and administration of the Canaxas and Grey Wolf assets are shared on a pro-rata basis, based on revenue.

During the year ended December 31, 2002, $2,967,200 was charged to Canaxas with respect to the Management Agreement (2001 - $2,633,716 and 2000 - $3,456,023). Abraxas also charged the Company a corporate service charge of $885,000 for the year ended December 31, 2002 of which $480,000 was charged out to Canaxas. For the year ended December 31, 2001, the Abraxas corporate service charge was $849,000 (2000 - $Nil) of which $589,000 (2000 - $Nil) was charged out to Canaxas. All amounts relating to the Abraxas corporate service charge and the Management Agreement with Canaxas are non-interest bearing, are not collateralized and are due on demand.

At December 31, 2002 and 2001, the Company had a long-term receivable from Canaxas in the amount of $10,000,000 (Note 4) (2000 - $Nil). The balance bears interest at 9.65% and has no fixed terms of repayment. Interest and financing charges of $4,518,000 for the year ended December 31, 2002 are net of $965,000 interest income accrued ($Nil for comparative periods presented) related to the long-term receivable from Canaxas.

Following is a summary of amounts included in accounts receivable, long-term receivable and accounts payable that are due from (to) related parties as at December 31, 2002 and 2001:

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10. RELATED PARTY TRANSACTIONS (Continued)

	2002 $	2001 $
Short-term receivable from Canaxas	1,236	4,330
Long-term receivable from Canaxas	10,000	10,000
Short-term payable to Abraxas	-	(849)

11. CONTINGENCIES

The Company is subject to various claims arising from its operations in the normal course of business, none of which are expected, individually or in the aggregate, to have a material adverse impact on the Company's operations or financial position.

12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Reconciliation to United States Generally Accepted Accounting Principles

The financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), which in most respects, conform to accounting principles generally accepted in the United States of America ("U.S. GAAP"). Differences from U.S. GAAP

having a significant effect on the Company's balance sheets and statements of earnings (loss) and retained earnings (deficit) and of cash flows are described and quantified below for the years indicated:

(a) Under U.S. GAAP, interest costs associated with certain capital expenditures are required to be capitalized as part of the historical cost of the oil and gas assets. Under Canadian GAAP, the calculation of interest costs eligible for capitalization differs from the calculation under U.S. GAAP in certain respects and is optional at the discretion of the entity. Accordingly, no amounts have been capitalized with respect to the Canadian GAAP financial statements. The impact of recording capitalized interest under U.S. GAAP would be to increase the carrying value of property and equipment by $168,000 in 2002, $119,000 in 2001 and $69,000 in 2000 with a corresponding decrease in interest expense in the respective periods. There was no cumulative adjustment under U.S. GAAP for years prior to 2000.

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12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

(b) In September 2001, Abraxas acquired the remaining non-controlling interest of the Company. Consideration was comprised of 0.6 common shares of Abraxas, in exchange for each common share of the Company. Under U.S. GAAP, the costs assigned to assets and liabilities by the acquiring company under a business combination are considered to constitute a new basis of accounting. Accordingly, the historical carrying values of assets and liabilities of the subsidiary are comprehensively revalued based on the purchase price assigned for consolidation purposes at the time it becomes wholly owned ("push down accounting"). Under Canadian GAAP, comprehensive revaluation of assets and liabilities in the financial statements of a subsidiary based on a purchase transaction involving acquisition of all of the equity interests is permitted, but not required. Had the consolidation entries of Abraxas related to the acquisition been applied in the Company's financial statements using "push down accounting", property and equipment and future income tax liability would be reduced by $4,074,000 and $1,736,000, respectively, accounts receivable would be increased and interest and financing charges decreased by $984,000 (relating to certain costs of the transaction paid by the Company), with the remaining amount of $2,338,000 recorded as a revaluation adjustment within shareholders' equity.

(c) Under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities at the balance sheet date, net of deferred income taxes and accumulated site restoration and abandonment liability, is limited to the present value of after-tax future net revenue from proven reserves, discounted at 10 percent, plus the lower of cost and fair value of unproved oil and gas properties. Under Canadian GAAP, the "ceiling test" calculation is performed using undiscounted after-tax net revenues, less future estimated general and administrative and financing costs plus the lower of cost and fair value of unproved oil and gas properties. Had the ceiling test been applied in accordance with U.S. GAAP, the write-down recorded for the year ended December 31, 2002 would have been lower by $41,155,000 ($25,464,000 after-tax). There were no differences between the application of the Canadian and U.S. GAAP ceiling tests in 2001 and 2000, or for years prior to 2000.

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12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

(d) Prior to 2000, Canadian GAAP required the use of the deferral method of accounting for income taxes. For fiscal periods beginning on or after January 1, 2000, retroactive adoption of the liability method of accounting for income taxes was required, which is substantially the same as Financial Accounting Standards Board Statement No. 109 under U.S. GAAP. However, upon adoption of the new recommendation for Canadian GAAP, companies were permitted to record the impact of differences in accounting and tax bases to retained earnings as a one-time transition adjustment. Accordingly, property and equipment would have been higher under U.S. GAAP by $682,000 for 2002 and 2001 before the impact of depletion. In addition, future income tax expense of $480,000 would have been recorded for 1999 under U.S. GAAP.

(e) As a result of the Canadian - U.S. GAAP differences in capitalization of interest, "push down accounting", ceiling test write-down and adoption of the deferral method of accounting for incomes taxes as outlined in (a), (b), (c) and (d), respectively, depletion and depreciation expense and property and equipment under U.S. GAAP have been adjusted for each of the years ended December 31, 2002, 2001 and 2000. The cumulative increase in depletion and depreciation expense for years prior to 2000 was $158,000.

(f) Future income taxes have been adjusted for the year ended December 31, 2002 for the tax impact of the Canadian - U.S. GAAP differences outlined in (a) through (e). Except for the impact on future tax expense for 1999 as noted in (d), the cumulative impact on future income taxes for years prior to 2002 was not significant.

(g) Prior to 2001, Canadian GAAP required the use of the imputed earnings method for purposes of the calculation of fully diluted earnings per share. For fiscal periods beginning on or after January 1, 2001, retroactive application of the treasury stock method with restatement of prior periods is required, which is substantially the same as Financial Accounting Standards Board Statement No. 128 under U.S. GAAP. Accordingly, no adjustments are required to conform the diluted earnings (loss) per share figures to U.S. GAAP, except for the net income (loss) effect of the above-noted Canadian - U.S. GAAP differences identified.

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12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

The application of U.S. GAAP would have the following effect on the Statements of Earnings (Loss):

	Years Ended Decemb	
	2002	2001

	$	$
Net earnings (loss), as reported	(47,613)	4,
Capitalized interest (a)	168	
Depreciation, depletion and site restoration (e)	(2,401)	(
Write-down of petroleum and natural gas properties and facilities (c)	41,155	
Interest and financing charges (b)	-	
Future income tax expense (recovery) (f)	(14,495)	
Net earnings (loss), U.S. GAAP	(23,186)	5,
Basic and diluted earnings (loss) per share, as reported	(3.71)	0
Effect of increase (decrease) in net earnings (loss) under U.S. GAAP	1.90	0
Basic and diluted earnings (loss) per share, U.S. GAAP (g)	(1.81)	0

12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

The application of U.S. GAAP would have the following effect on the Balance Sheets:

	As At December 31, 2002			
	As Reported	Cumulative Increase (Decrease)	U.S. GAAP	As Repor
ASSETS				
Accounts receivable (b)	8,230	984	9,214	9,9
Property and equipment (a)(b)(c)(d)(e)	23,401	35,414	58,815	71,8
Future income taxes (f)	25,233	(12,759)	12,474	
LIABILITIES				
Future income taxes (d)(f)	-	-	-	6,3
SHAREHOLDERS' EQUITY (DEFICIENCY)				
Revaluation adjustment (b)	-	(2,338)	(2,338)	
Retained earnings (deficit)				

(a)(b)(c)(d)(e)(f)	(38,188)	25,977	(15,255)	9,4

12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

The application of U.S. GAAP would have the following effect on the Statements of Cash Flows:

	Years Ended De	
	2002 $	2001 $
OPERATING ACTIVITIES		
Cash flow from operating activities, as reported	8,712	14,8
Increase (decrease) in:		
Net earnings (loss)	24,427	1,0
Depletion, depreciation and site restoration (e)	2,401	
Write-down of petroleum and natural gas properties and facilities (c)	(41,155)	
Future income tax expense (recovery) (f)	14,495	
Changes in non-cash working capital items (b)	-	(9
Cash flow from operating activities, U.S. GAAP	8,880	14,9
INVESTING ACTIVITIES		
Net cash (used) provided by investing activities, as reported	(42,023)	(29,0
Increase in capital expenditures (a)	(168)	(1
Net cash (used) provided by investing activities, U.S. GAAP	(42,191)	(29,1

The investing activities portion of the statement of cash flows for 2000 prepared under Canadian GAAP discloses the aggregate costs related to a property swap arrangement, with adjustments to arrive at the cash component of the transaction. Under U.S. GAAP only the net cash amount would be presented on the statement of cash flows.

12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

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.

Recent U.S. Accounting Developments

Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) was released by the Financial Accounting Standards Board in June 2001. FAS 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. The initial amount of the asset retirement obligation is to be recorded at fair value. The asset retirement cost equal to the fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. Enterprises are required to adopt FAS 143 for fiscal years beginning after June 15, 2002. The Company is currently assessing the impact that adoption of this standard would have on its financial position and results of operations, in conjunction with the January 23, 2003 transaction as described in Note 13.

The Financial Accounting Standards Board also recently issued Statement No. 144, "Accounting for the Impairment of Disposal of Long-Lived Assets" (FAS 144). FAS 144 will replace previous United States generally accepted accounting principles regarding accounting for impairment of long-lived assets and accounting and reporting for discontinued operations. FAS 144 retains the fundamental provisions of the prior standard for recognizing and measuring impairment losses on long-lived assets. FAS 144 retains the basic provisions of the prior standard for presentation of discontinued operations in the income statement, but broadens that presentation to include a component of an entity rather than a segment of a business. Enterprises are required to adopt FAS 144 for fiscal years beginning after December 15, 2001. The Company has adopted the accounting standard effective January 1, 2002. The standard is not expected to have a significant future impact on the Company's financial position and results of operations.

12. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (Continued)

The Financial Accounting Standards Board also recently issued Statement No. 146, "Accounting for Costs Associated With Exit or Disposal Activities" (FAS 146). FAS 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity

(including Certain Costs Incurred in a Restructuring)." The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The standard is not expected to have a significant impact on the Company's financial position or results of operations.

13. SUBSEQUENT EVENTS

On January 23, 2003, Abraxas completed the sale of all of the outstanding common shares of the Company to an unrelated third party (the "Purchaser") for gross cash proceeds of approximately $110,790,000, subject to closing adjustments. Upon closing of the sale, the Company was required to repay the outstanding indebtedness including accrued interest under the Mirant Facility, totaling $72,847,000. Prior to the sale, certain petroleum and natural gas assets of the Company with a net book value of $8,871,000 were transferred to a related newly-formed subsidiary of Abraxas, a portion of which will be developed jointly under farmout arrangements with the Purchaser.