ABRAXAS PETROLEUM CORP
Form 10-K
March 23, 2006

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(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, 2005

[ ] 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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] No [X]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
Yes [ ] No [X]

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]

As of June 30, 2005, the aggregate market value of the common stock held by non-affiliates of the registrant was $82,831,075 based on the closing sale price as reported on the American Stock Exchange.

As of March 21, 2006, there were 42,588,327 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2006 Annual Meeting of Shareholders to be held on May 25, 2006.	Part III

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PART I

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 statements including words like "believe", "expect", "anticipate", "intend", "plan", "seek", "estimate", "could", "potentially" or similar expressions), you must remember that these are forward-looking statements, and 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 "Summary", "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 success in development, exploitation and exploration activities;
- our ability to make planned capital expenditures;
- declines in our production of natural gas and crude oil;
- prices for natural gas and crude oil;
- our ability to raise equity capital or incur additional indebtedness;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- prices and availability of alternative fuels;
- our restrictive debt covenants;

- our acquisition and divestiture activities;
- results of our hedging activities; and
- other factors discussed elsewhere in this report.

PART I

Item 1. Business

As part of a series of restructuring transactions approved in 2004, we adopted a plan to dispose of our operations and interest in Grey Wolf Exploration Inc., a wholly-owned Canadian subsidiary of Abraxas Petroleum Corporation. In February 2005, Grey Wolf closed on an initial public offering resulting in our substantial divestiture of our capital stock in Grey Wolf. As a result of the disposal of Grey Wolf, the results of operations of Grey Wolf are reflected in our Financial Statements and in this document as "Discontinued Operations" and our remaining operations are referred to in our Financial Statements and in this document as "Continuing Operations" or "Continued Operations". Unless otherwise noted, all disclosures are for continuing operations. See Note 3 to the financial statements in Item 8.

In this report, 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 or natural gas liquids and MBbls is used to designate one thousand barrels of crude oil or natural gas liquids.

General

We are an independent energy company primarily engaged in the development and production of natural gas and crude oil. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a substantial inventory of development opportunities, which provide a basis for significant production and reserve increases. In addition, we intend to expand upon our exploitation and development activities with complementary exploration projects in our core areas of operation.

Our core areas of operation are in south and west Texas and east central Wyoming. Our current producing properties are typically characterized by long-lived reserves, established production profiles and an emphasis on natural gas. At December 31, 2005, we owned interests in 102,356 gross acres (88,374 net acres) applicable to our continuing operations, and operated properties accounting for approximately 94% of our PV-10, affording us substantial control over the timing and incurrence of operating and capital expenditures. At December 31, 2005, estimated total proved reserves were 104.7 Bcfe with an aggregate PV-10 of $311.9 million. During 2005, we participated in the drilling of 12 gross (12 net) wells with 11 gross (11 net) wells being successful. We invested $35.0 million in capital spending on these activities during 2005. As a result of these activities we produced 6.1 Bcfe during 2005 and replaced 280% of 2005 production according to our year-end reserve report.

We believe that our high quality asset base, high degree of operational control and large inventory of drilling projects positions us for future growth. Our properties are concentrated in locations that facilitate substantial economies of scale in drilling and production operations and efficient reservoir management practices. In addition, we have 53 proved undeveloped projects and have identified over 184 drilling and recompletion opportunities on our existing acreage, the successful development of which we believe could significantly increase our daily production and proved reserves. We have approved a capital budget of approximately $40.0 million for 2006 which will be used primarily for the development of our current properties as well as to drill and complete wells that were in progress at the end of 2005. This drilling program will be funded by cash flow from operations, availability under our revolving credit facility and if necessary, equity financing. Our ability to complete this drilling program may also be limited due to the lack of availability of drilling rigs and other equipment.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of, and demand for, natural gas and crude oil. Historically, the markets for natural gas and crude oil have been volatile and are likely to continue to be volatile in the future. The prices we receive for our natural gas and crude oil 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 natural gas and crude oil 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 - Risks Relating to Our Industry -- Market conditions for natural gas and crude oil, and particularly volatility of prices for natural gas and crude oil, could adversely affect our revenue, cash flows, profitability and growth" and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies" for more information relating to the effects of decreases in natural gas and crude oil prices on us.

Substantially all of our natural gas and crude oil is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2005, two purchasers accounted for approximately 61% of our natural gas and crude oil sales. We believe that there are numerous other companies available to purchase our natural gas and crude oil and that the loss of one or more of these purchasers would not materially affect our ability to sell natural gas and crude oil.

Regulation of Natural Gas and Crude Oil 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 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, and 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 were subject to significant federal regulation. At the present time, however, all sales of our crude oil, natural gas, condensate and NGLs produced under private contracts may be sold at market prices. Congress could, however, re-enact price controls in the future. If controls that limit prices to below market rates are instituted, our revenue could be adversely affected.

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. Currently, the Federal Energy Regulatory Commission ("FERC), requires 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 are not required to remain "merchants" of natural gas, and most of the interstate pipeline companies have become "transporters only", although many have affiliated marketers.

Transportation pipeline availability and shipping 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 into the pipeline transportation systems remain subject to extensive Federal regulation. Although FERC 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. FERC continues to review and modify its regulations regarding the transportation of natural gas. The 2005 Energy Policy Act recently authorized FERC to allow natural gas companies subject to the FERC's Natural Gas Act jurisdiction to provide gas storage and storage-related services at market-based rates for new storage capacity of a storage facility placed in service after the date of the Act's August 2005 passage, thereby enhancing competition in the market for interstate natural gas storage service.

In recent years FERC also has pursued a number of important policy initiatives which could significantly affect the marketing of natural gas in the United States. Most of these initiatives are intended to enhance competition in natural gas markets. FERC rules encouraging "spin downs", or the breakout of unregulated gathering activities from regulated transportation services, 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 certain facilities by their new, unregulated owners. Note, however, that FERC currently is pursuing an inquiry into whether it should revise its test for determining whether and under what circumstances FERC may reassert jurisdiction over natural gas gathering companies that have been "spun-down" from an affiliated interstate natural gas pipeline to prevent abusive practices by the gatherer and its pipeline affiliate. Any action taken by FERC in this proceeding will be intended by it to enhance competition in the gas transportation sector. As to all FERC initiatives, the ongoing, or, in some instances, preliminary and evolving nature of such matters makes it impossible at this time to predict their ultimate impact on our business. However, we do not believe that any FERC initiatives will affect us any differently than other natural gas producers and marketers with which we compete.

FERC decisions involving onshore facilities are more liberal in their reliance upon traditional tests for determining what facilities are "gathering" and therefore are exempt from federal regulatory control. In many instances, what was in the past classified as "transmission" may now be classified as "gathering". We ship certain of our natural gas through gathering facilities owned by others. Although FERC decisions create 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 FERC activities related to the transportation of natural gas result 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, 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 natural gas and crude oil industry historically has been very heavily regulated; thus there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future.

State and Other Regulation

All of the jurisdictions in which we own producing natural gas and crude oil properties have statutory provisions regulating the exploration for and production of natural gas and crude oil. These include 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 natural gas and crude oil properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from natural gas and crude oil 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 has the potential 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 regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service 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 FERC 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 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, on Federal Lands in the United States, the Minerals Management Service ("MMS") prescribes or severely limits the types of costs that are deductible transportation costs for purposes of royalty valuation of production sold off the lease. In particular, MMS prohibits 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 natural gas and crude oil 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.

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Environmental Matters

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

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.

Superfund. 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. In the course of our ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. 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 natural gas and crude oil. 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 (as defined below), and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators; to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

Oil Pollution Act of 1990. 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. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

U.S. Environmental Protection Agency. U.S. Environmental Protection Agency regulations address the disposal of crude oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, crude oil and natural gas wastes are regulated by the Underground Injection Control program under the Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed of at an approved hazardous waste facility. We have coverage under the applicable Clean Water Act permitting requirements for discharges associated with exploration and development activities. Resource Conservation Recovery Act. RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the crude oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain crude oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for crude oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from crude oil and natural gas production. The Safe Drinking Water Act of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandate provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

Naturally Occurring Radioactive Materials ("NORM"). NORM are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the crude oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards established by the State of Texas.

Abandonment Costs. All of our crude oil and natural gas wells will require proper plugging and abandonment when they are no longer producing. We post bonds with most regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface production site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Title to Properties

As is customary in the natural gas and crude oil industry, we make only a cursory review of title to undeveloped natural gas and crude oil 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/lessor 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 natural gas and crude oil properties, some of which are subject to immaterial encumbrances, easements and restrictions. The natural gas and crude oil 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.

Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of natural gas and crude oil are leasehold prospects under which natural gas and crude oil reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of natural gas and crude oil operations. We must compete for such resources with both major natural gas and crude oil companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. 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. For more information, you should read "Risk Factors - Risks Related to Our Industry - We operate in a highly competitive industry which may adversely affect our operations." and "- The unavailability or high cost of drilling rigs, equipment, supplies, insurance, personnel and crude oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget."

Employees

As of March 21, 2006 we had 48 full-time employees in the United States, including two executive officers, three non-executive officers, one petroleum engineer, one geologist, five managers, one landman, ten administrative and support personnel and 25 field personnel. Additionally, we retain contract gaugers 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.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments filed with the Securities and Exchange Commission are available free of charge on our web site at www.abraxaspetroleum.com in the Investor Relations section as soon as practicable after such reports are filed.

Item 1A. Risk Factors

Risks Related to Our Business

We have a highly leveraged capital structure, which limits our operating and financial flexibility.

We have a highly leveraged capital structure. At March 21, 2006, we had total indebtedness, including our floating rate senior secured notes due 2009, or notes, which we issued in connection with our October 2004 refinancing, of approximately $130.8 million, all of which is secured indebtedness. We also had availability of $9.2 million under our $15.0 million senior secured revolving credit facility, all of which is also secured indebtedness.

Our highly leveraged capital structure will have several important effects on our future operations, including:

- a substantial amount of our cash flow from operations will be required to service our indebtedness, which will reduce the funds that would otherwise be available for operations, capital expenditures and expansion opportunities, including developing our properties;

- the covenants contained in our revolving credit facility require us to meet certain financial tests and comply with certain other restrictions, including limitations on capital expenditures. These restrictions, together with those in the indenture governing the notes, may limit our ability to undertake certain activities and respond to changes in our business and our industry;

- our debt level may impair our ability to obtain additional capital, through equity offerings or debt financings, for working capital, capital expenditures, or refinancing of indebtedness;

- our debt level makes us more vulnerable to economic downturns and adverse developments in our industry (especially declines in natural gas and crude oil prices) and the economy in general; and

- the notes and our revolving credit facility are subject to variable interest rates which makes us vulnerable to interest rate increases.

We may not be able to fund the substantial capital expenditures that will be required for us to increase our reserves and our production.

We are required to make substantial capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have financed our capital expenditures primarily with cash flow from operations, borrowings under credit facilities, sales of producing properties, and sales of equity securities and we expect to continue to do so in the future; however, we cannot assure you that we will have sufficient capital resources in the future to finance our capital expenditures.

Volatility in natural gas and crude oil prices, the timing of our drilling program and our drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of our planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and our planned capital expenditures would, by necessity, be decreased.

The borrowing base under our revolving credit facility will be determined from time to time by our lenders, consistent with their customary natural gas and crude oil lending practices. Reductions in estimates of our natural gas and crude oil reserves could result in a reduction in our borrowing base, which would reduce the amount of financial resources available under our revolving credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices or production, inability to drill or unfavorable drilling results, changes in natural gas and crude oil reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

If cash flow from operations or our borrowing base decrease for any reason, our ability to undertake exploitation and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under our revolving credit facility is reduced, we would be required to reduce our borrowings under our revolving credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, could cause us to default under our revolving credit facility and the notes.

We have sold producing properties to provide us with liquidity and capital resources in the past and may do so in the future. After any such sale, we would expect to utilize the proceeds to drill new wells. If we cannot replace the production lost from properties sold with production from new properties, our cash flow from operations will likely decrease which, in turn, would decrease the amount of cash available for debt service and additional capital spending.

We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition would be adversely affected.

Our future natural gas and crude oil production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our natural gas and crude oil properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploitation activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration, exploitation and development activities will result in increases in our proved reserves. As our proved reserves, and consequently our production decline, our cash flow from operations and the amount that we are able to borrow under our revolving credit facility will also decline. In addition, approximately 52% of our total estimated proved reserves at December 31, 2005 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations.

Our production is currently concentrated in one well

Approximately 30% of our current production is from a single well in west Texas. If production from this well decreases, it would have a material impact on our revenues, cash flow from operations and financial condition. This well is subject to all of the risks typically associated with natural gas wells, including the risks described in "Risks Related to Our Industry - Our operations are subject to the numerous risks of natural gas and crude oil drilling and production activities."

We may not find any commercially productive natural gas or crude oil reservoirs.

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our capital investment. Drilling for natural gas and crude oil 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. The inherent risk of not finding commercially productive reservoirs will be compounded by the fact that 52% of our total estimated proved reserves at December 31, 2005 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. In addition, our properties may be susceptible to drainage from production by other operations on adjacent properties. If the volume of natural gas and crude oil we produce decreases, our cash flow from operations will decrease.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interest.

Our revolving credit facility and the indenture governing the notes contain a number of significant covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- make any change in the principal nature of our business;
- prepay, redeem, purchase or otherwise acquire any of our or our restricted subsidiaries' indebtedness;
- permit a change of control;
- directly or indirectly make or acquire any investment;
- cause a restricted subsidiary to issue or sell our capital stock; and
- consolidate, merge or transfer all or substantially all of the consolidated assets of Abraxas and our restricted subsidiaries.

In addition, our revolving credit facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our revolving credit facility and the notes. A default, if not cured or waived, could result in all of our indebtedness, including the notes, becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

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 and transportation 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 regulation of natural gas and crude oil 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 natural gas and crude oil.

Hedging transactions have in the past and may in the future impact our cash flow from operations.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and crude oil prices and to achieve more predictable cash flow. In 2003 and 2005, we incurred hedging costs of $842,000 and $592,000, respectively, resulting from the price floors we established . For the year ended December 31, 2004, we recognized a gain from hedging activities of approximately $118,000. Currently, we believe our hedging arrangements, which are in the form of price floors, do not expose us to significant financial risk.

We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from financial loss due to circumstances such as:

- highly volatile natural gas and crude oil prices;
- our production being less than expected; or
- a counterparty to one of our hedging transactions defaulting on our contractual obligations.

We have experienced significant operating losses in the past.

We recorded net losses from continuing operations for 2003 of $12.8 million. We recorded net income from continuing operations for 2004 and 2005 of $3.0 million and $6.3 million, respectively. Net income from continuing operations in 2004 included $12.6 million of gain on debt extinguishment relating to our October 2004 refinancing and a deferred tax benefit of $6.1 million. We cannot assure you that we will continue to be profitable in the future.

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

We use the full cost method to account for our natural gas and crude oil operations. Accordingly, we capitalize the cost to acquire, explore for and develop natural gas and crude oil properties. Under full cost accounting rules, the net capitalized cost of natural gas and crude oil 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%. If net capitalized costs of natural gas and crude oil 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 natural gas and crude oil properties increases when natural gas and crude oil 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 natural gas and crude oil prices may have increased the ceiling applicable to the subsequent period.

We have incurred ceiling limitation write-downs in the past. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2005, we had, subject to the limitation discussed below, $190.0 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2025 if not utilized. In addition, 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. Moreover, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109.

Therefore, we have established a valuation allowance of $73.0 million and $67.0 million for deferred tax assets at December 31, 2004 and 2005, respectively.

We depend on our Chairman, President and CEO and the loss of his services could have an adverse effect on our operations.

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. Mr. Watson may terminate his employment agreement with us at any time on 30 days notice, but, if he terminates without cause, he would not be entitled to the severance benefits provided under the terms of that agreement. Mr. Watson is not precluded from working for, with or on behalf of a competitor upon termination of his employment with us. If Mr. Watson were no longer able or willing to act as our Chairman, the loss of his services could have an adverse effect on our operations. In addition, in connection with the initial public offering by our previously wholly-owned subsidiary, Grey Wolf Exploration Inc., we, Grey Wolf and Mr. Watson agreed that Mr. Watson would continue to serve as our Chief Executive Officer and President and as the Chief Executive Officer for Grey Wolf, with Mr. Watson devoting two-thirds of his time to his positions and duties with us and one-third of his time to his position and duties with Grey Wolf. In consideration for receiving Mr. Watson's services, Grey Wolf makes an annual payment to Abraxas of US$100,000 and reimburses Abraxas for Mr. Watson's expenses incurred in connection with providing such services.

Risks Related to Our Industry

Market conditions for natural gas and crude oil, and particularly volatility of prices for natural gas and crude oil, 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 natural gas and crude oil. 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. Lower prices may also make it uneconomical for us to increase or even continue current production levels of natural gas and crude oil.

Prices for natural gas and crude oil are subject to large fluctuations in response to relatively minor changes in the supply and demand for natural gas and crude oil, market uncertainty and a variety of other factors beyond our control, including:

- changes in foreign and domestic supply and demand for natural gas and crude oil;
- political stability and economic conditions in oil producing countries, particularly in the Middle East;
- general economic conditions;
- domestic and foreign governmental regulation; and
- the price and availability of alternative fuel sources.

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

- reducing the overall volume of natural gas and crude oil that we can produce economically, thereby adversely affecting our revenue, profitability and cash flow and our ability to perform our obligations with respect to the notes;
- reducing our borrowing base under the credit facility; and
- impairing our borrowing capacity and our ability to obtain equity capital.

Estimates of our proved reserves and future net revenue are uncertain and inherently imprecise.

The process of estimating natural gas and crude oil reserves is complex involving decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, natural gas and crude oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil 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 report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploitation and development, prevailing natural gas and crude oil prices and other factors, many of which are beyond our control.

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 natural gas and crude oil reserves, future net revenue from proved reserves and the PV-10 thereof for our natural gas and crude oil properties are based on the assumption that future natural gas and crude oil prices remain the same as natural gas and crude oil prices at December 31, 2005. The sales prices as of such date used for purposes of such estimates were $8.84 per Mcf of natural gas and $56.92 per Bbl of crude oil. This compares with $4.94 per Mcf of natural gas and $41.01 per Bbl of crude oil as of December 31, 2004. These estimates also assume that we will make future capital expenditures of approximately $84.2 million in the aggregate through 2024, with the majority expected to be incurred from 2006 to 2009, 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 in this report.

The present value of future net revenues we disclose may not be the current market value of our estimated natural gas and crude oil 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 natural gas and crude oil 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 natural gas and crude oil industry in general will affect the accuracy of the 10% discount factor.

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

Our natural gas and crude oil drilling and production activities are subject to numerous risks, many of which are beyond our control. These 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 and discharges of toxic gases. In addition, title problems, weather conditions and mechanical difficulties or shortages or delays in delivery of drilling rigs and other equipment could negatively affect our operations. If any of these or other similar 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. The principal resources necessary for the exploration and production of natural gas and crude oil are leasehold prospects under which natural gas and crude oil reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of natural gas and crude oil operations. We must compete for such resources with both major natural gas and

crude oil companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. 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.

The unavailability or high cost of drilling rigs, equipment, supplies, insurance, personnel and crude oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, insurance or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. As a result of increasing levels of exploration and production in response to strong prices of natural gas and crude oil, the demand for oilfield services has risen and the costs of these services are increasing.

Our natural gas and crude oil operations are subject to various Federal, state and local regulations that materially affect our operations.

Matters regulated include 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 natural gas and crude oil, these agencies have restricted the rates of flow of natural gas and crude oil wells below actual production capacity. Federal, state and local laws regulate production, handling, storage, transportation and disposal of natural gas and crude oil, by-products from natural gas and crude oil and other substances and materials produced or used in connection with natural gas and crude oil 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.

Risks Related to the Common Stock

We do not pay dividends on common stock.

We have never paid a cash dividend on our common stock and the terms of the revolving credit facility and the indenture relating to the notes limit our ability to pay dividends on our common stock.

Shares eligible for future sale may depress our stock price.

At March 21, 2006, we had 42,588,327 shares of common stock outstanding of which 3,991,679 shares were held by affiliates and, in addition, 2,588,963 shares of common stock were subject to outstanding options granted under certain stock option plans (of which 1,699,838 shares were vested at March 21, 2006).

All of the shares of common stock held by affiliates are restricted or control securities under Rule 144 promulgated under the Securities Act of 1933, as amended (the "Securities Act"). The shares of the common stock issuable upon exercise of the stock options have been registered under the Securities Act. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of the common stock and could impair our ability to raise additional capital through the sale of equity securities.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Our common stock is traded on The American Stock Exchange. The market price of our common stock has been volatile and could fluctuate substantially based on a variety of factors, including the following:

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the industry;
- market conditions; and
- analysts' estimates and other events in the natural gas and crude oil industry.

We may issue shares of preferred stock with greater rights than our common stock.

Subject to the rules of The American Stock Exchange, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock.

Anti-takeover provisions could make a third party acquisition of Abraxas difficult.

Our articles of incorporation and bylaws provide for a classified board of directors, with each member serving a three-year term, and eliminate the ability of stockholders to call special meetings or take action by written consent. Each of the provisions in the articles of incorporation and bylaws could make it more difficult for a third party to acquire Abraxas without the approval of our board. In addition, the Nevada corporate statute also contains certain provisions that could make an acquisition by a third party more difficult.

An active market may not develop for our common stock.

Our common stock is quoted on The American Stock Exchange. While there is currently one specialist in our common stock, this specialist is not obligated to continue to make a market in our common stock. In this event, the liquidity of our common stock could be adversely impacted and a stockholder could have difficulty obtaining accurate stock quotes.

Future issuance of additional shares of our common stock could cause dilution of ownership interests and adversely affect our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our current stockholders. We are currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Primary Operating Areas

Texas

Our operations are concentrated in south and west Texas with over 99% of the PV-10 of our natural gas and crude oil properties at December 31, 2005 located in those two regions. We operate 91% of our wells in Texas. During 2005, we drilled a total of eight new wells (eight net) in Texas with an 88% success rate, with a total of 1.1 Bcfe of our 2005 production attributable to new wells drilled in Texas. Operations in south Texas are concentrated along the Edwards trend in Live Oak, DeWitt and Lavaca Counties, the Frio/Vicksburg trend in San Patricio County and the Wilcox trend in Goliad and DeWitt Counties. In total in south Texas, we own an average 93% working interest in 46 wells with average production of 200 net Bbls of crude oil and 6,778 net Mcf of natural gas per day for the year ended December 31, 2005. As of December 31, 2005, we had estimated net proved reserves in South Texas of 30.3 Bcfe (84% natural gas) with a PV-10 of $107.0 million, 61% of which was attributable to proved developed reserves.

Our west Texas operations are concentrated along the deep Devonian/Montoya/Ellenburger formations and shallow Cherry Canyon sandstones in Ward County, the Sharon Ridge Clearfork Field in Scurry and Mitchell Counties and Devonian, Woodford and Wolfcamp formations in Pecos County. We drilled one well in west Texas that contributed approximately 10% of our 2005 production and is currently contributing approximately 30% of our production.

In total in west Texas, we own an average 74% working interest in 165 wells with average daily production of 296 net Bbls of crude oil and NGLs and 9,735 net Mcf of natural gas per day for the year ended December 31, 2005. As of December 31, 2005, we had estimated net proved reserves in west Texas of 73.0 Bcfe (83% natural gas) with a PV-10 of $201.9 million, 42% of which was attributable to proved developed reserves.

In the Oates SW Field of west Texas, our workover rig continues to clean out the vertical section on a Devonian re-entry well, which after reaching approximately 12,500', we plan to drill horizontally. We plan to continue development of the Oates SW Field throughout 2006, targeting the shallower Wolfcamp, Atoka and Woodford formations in addition to the deeper Devonian. In the multi-well re-completion program elsewhere in the Delaware Basin of West Texas, we are currently recovering completion fluid from two wells that were fracture stimulated in the Atoka formation while a third well, which was re-completed to the Wolfcamp formation, is flowing oil and gas. We plan to re-complete or fracture stimulate four to six additional wells in this program during 2006. In the Sharon Ridge Field located in Scurry County, Texas, we have begun drilling a shallow well targeting the Clear Fork formation at a depth of 3,500'. We plan to drill one additional in-fill well in this field in 2006.

Wyoming

We currently hold 52,994 acres in the Powder River Basin in east central Wyoming. We have drilled and operate ten wells in Converse and Niobrara counties that were completed in the Muddy, Mowry, Turner, and Niobrara formations. Four of these wells were drilled in the latter part of 2005 and are currently undergoing completion and stimulation. We own a 100% working interest in these wells that produced an average of 37 net barrels of crude oil per day in 2005. As of December 31, 2005, we had estimated net proved producing reserves in Wyoming of 242,036 barrels of crude oil with a PV-10 of $3.0 million.

In Brooks Draw, Wyoming, production testing continues on the four wells drilled in late 2005. Since the beginning of 2006, one additional formation has been perforated and awaits fracture stimulation and a previously completed formation has been re-stimulated. We plan to complete additional zones as service equipment becomes available. Once all of the formations are completed and tested individually, they will be commingled and an ultimate sustained rate of production can be obtained. We plan to drill several more wells in Wyoming during the second half of 2006.

Exploratory and Developmental Acreage

Our principal natural gas and crude oil properties consist of non-producing and producing natural gas and crude oil leases, including reserves of natural gas and crude oil in place. The following table indicates our interest in developed and undeveloped acreage and fee mineral acreage applicable to continuing operations as of December 31, 2005:

	Developed Acreage (1)		Undeveloped Acreage (2)		Fee Mineral Acreage (3)	
	Gross Acres(4)	Net Acres (5)	Gross Acres(4)	Net Acres (5)	Gross Acres (6)	Net Acres
South Texas	6,271	5,842	1,236	1,158	-	-
West Texas	19,117	14,570	18,135	12,315	12,007	5,272
Wyoming	3,360	3,360	49,634	45,833	-	-
N. Dakota	-	-	80	24	-	-
Total	28,748	23,772	69,085	59,330	12,007	5,272

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(1) Developed acreage consists of leased 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 natural gas and crude oil, regardless of whether or not such acreage contains proved reserves.

(3) Fee mineral acreage represents fee simple absolute ownership of the mineral estate or fraction thereof.

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

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

(6) Includes 7,484 acres that are included in developed and undeveloped gross acres.

Productive Wells

The following table sets forth our total gross and net productive wells applicable to continuing operations, expressed separately for natural gas and crude oil, as of December 31, 2005:

	Productive Wells (1) As of December 31, 2005			
State	Crude Oil		Natural Gas	
	Gross(2)	Net(3)	Gross(2)	Ne
South Texas	17.0	17.0	29.0	2
West Texas	128.0	99.5	37.0	2
Wyoming	10.0	10.0	18.0	
N. Dakota	-	-	1.0	
Total	155.0	126.5	85.0	4

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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.
(3) A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

Reserves Information

The natural gas and crude oil reserves have been estimated as of December 31, 2005, December 31, 2004, and December 31, 2003, by DeGolyer and MacNaughton, of Dallas, Texas. Natural gas and crude oil 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

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the estimate of future net recoverable reserves of natural gas and crude oil and the timing and amount of future net revenues to be received therefrom. 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 December 31, 2003, December 31, 2005 and December 31, 2005 relating to continuing operations.

	Estimated Proved Reserves		
	Proved Developed	Proved Undeveloped	Total Proved
As of December 31, 2005			

Crude oil (MBbls)	1,942	1,142	3,084
Natural gas (MMcf)	38,794	47,409	86,203
As of December 31, 2004			
Crude oil (MBbls)	1,878	1,223	3,101
Natural gas (MMcf)	36,241	38,877	75,118
As of December 31, 2003			
Crude oil (MBbls)	1,791	1,264	3,055
NGLs (MBbls)	95	170	265
Natural gas (MMcf)	39,371	40,831	80,202

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, natural gas and crude oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil 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 exploitation and development, prevailing natural gas and crude oil 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 natural gas and crude oil 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. Because we use the full cost method to account for our natural gas and crude oil operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. This is known as a "ceiling limitation write-down". This charge does not impact cash flow from operating activities but does reduce our stockholders' equity and reported earnings. We have experienced ceiling limitation write-downs in the past and we cannot assure you that we will not experience additional ceiling limitation write-downs in the future. For more information regarding the full cost method of accounting, you should read the information under "Management's Discussion and Analysis of Financial Condition and Results of Operation - Critical Accounting Policies".

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 natural gas and crude oil 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 natural gas and crude oil 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 natural gas and crude oil reserves, future net revenue from proved reserves and the PV-10 thereof for the natural gas and crude oil properties described in this report are based on the assumption that future natural gas and crude oil prices remain the same as natural gas and crude oil prices at December 31, 2005. The average sales prices as of such date used for purposes of such estimates were $56.92 per Bbl of crude oil and $8.84 per Mcf of natural gas. It is also assumed that we will make future capital expenditures of approximately $84.2 million in the aggregate, most of which is in the years 2006 through 2009, 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 natural gas and crude oil reserves with the Department of Energy. The reserves reported to this agency 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 Mcfe of production sold, for the three years ended December 31, 2005 related to continuing operations:

	2005	2004	2003
Crude oil production (Bbls)	194,366	220,409	220
Natural gas production (Mcf)	4,942,355	4,403,030	4,780
Natural gas liquids production (Bbls)	-	8,875	9
Total production (Mmcfe) (2)	6,109	5,779	6
Average sales price per Bbl of crude oil	$ 53.27	$ 40.12	$ 3
Average sales price per Mcf of natural gas (1)	$ 7.48	$ 5.45	$
Average sales price per Bbl of natural gas liquids	$ -	$ 26.32	$ 2
Average sales price per Mcfe	$ 7.75	$ 5.72	$
Average cost of production per Mcfe produced (2)	$ 1.82	$ 1.48	$

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(1) Average sales prices are net of hedging activity.

(2) Natural gas and crude oil were combined by converting crude oil and natural gas liquids to a Mcf equivalent 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, related to continuing operations during the three years ended December 31, 2005:

	2005		2004		2
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)
Exploratory(3)					
Productive(4)					
Crude oil	1.0	1.0	2.0	2.0	1.0
Natural gas	1.0	1.0	-	-	-
Dry holes(5)	-	-	-	-	-
Total	2.0	2.0	2.0	2.0	1.0
Development(6)					
Productive (4)					
Crude oil	4.0	4.0	-	-	-
Natural gas	5.0	5.0	1.0	1.0	5.0
Dry holes (5)	1.0	1.0	1.0	1.0	-
Total	10.0	10.0	2.0	2.0	5.0

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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 natural gas or crude oil in an unproved area, to find a new reservoir in a field previously found to be producing natural gas or crude oil 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 natural gas or crude oil in sufficient quantities to justify completion as a natural gas or crude oil well.

(6) A development well is a well drilled within the proved area of a natural gas or crude oil reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved natural gas or crude oil reserves.

As of March 21, 2006, we had 7 wells in process of drilling and/or completing.

Office Facilities

Our executive and administrative offices are located at 500 North Loop 1604 East, Suite 100, San Antonio, Texas 78232, consisting of approximately 12,650 square feet leased through January 2009 at an aggregate base rate of

$20,773 per month. We also have an office in Midland, Texas consisting of 570 square feet leased through February 2008 at an aggregate base rate of $439 per month.

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, 160 acres of land in Coke County, Texas and 11,537 acres of fee land in Pecos County, Texas. We also own 22 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

From time to time, Abraxas is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2005, Abraxas was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on Abraxas.

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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, 2005.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our 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 sales price quoted for our common stock on the American Stock Exchange.

	Period	High	Low
2004			
	First Quarter	$ 3.64	$ 1.29
	Second Quarter	2.89	1.50
	Third Quarter	2.37	1.09
	Fourth Quarter	2.99	1.91
2005			
	First Quarter	$ 2.92	$ 1.92
	Second Quarter	3.38	2.15
	Third Quarter	8.99	2.71
	Fourth Quarter	9.25	5.15
2006	First Quarter (Through March 21, 2006)	$ 7.25	$ 5.24

Holders

As of March 21, 2006, we had 42,588,327 shares of common stock outstanding and had approximately 1,226 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 our notes and our revolving credit facility prohibit 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.

Item 6. Selected Financial Data

The following selected financial data as of and for the years ended is 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 31,			
	2005	2004 *	2003 *	20
	(Dollars in thousands except per s			
Total revenue - continuing operations	$ 48,625	$ 33,854	$ 30,380	$
Net income (loss)	$ 19,117 (5)	$ 12,360 (1)	$ 56,798 (2)	$ (
Net income (loss) - discontinued operations	$ 12,846 (5)	$ 3,323	$ 70,024 (2)	$
Net income (loss) - continuing operations	$ 6,271	$ 9,037	$ (13,226)	$

Net income (loss) per common share - diluted	$ 0.46	$ 0.32	$ 1.61	$
Weighted average shares outstanding - diluted (in thousands)	41,164	38,895	35,364 (6)	
Total assets	$ 121,866	$ 152,685	$ 126,437	$
Long-term debt, excluding current maturities	$ 129,527	$ 126,425	$ 184,649	$
Total stockholders' equity (deficit)	$ (23,701)	$ (53,464)	$ (72,203)	$ (

* Net income (loss) and net income (loss) from continuing operations for 2004, 2003, 2002 and 2001 reflect the retrospective adoption of SFAS 123R.

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(1) Includes gain on debt extinguishment of $12.6 million and a deferred tax benefit of $6.1 million.
(2) Includes gain on sale of foreign subsidiaries of $ 68.9 million in 2003.
(3) Includes ceiling limitation write-down of $116.0 million ($28.2 million related to continuing operations).
(4) Includes ceiling test write-down of $2.6 million in 2001, based on subsequent (March 22, 2002) realized prices, related to discontinued operations.
(5) Includes gain on the sale of foreign subsidiary of $17.3 million net of non-cash tax of $6.1 million.
(6) For the year ended December 31, 2003, 711,928 shares were excluded from the calculation of diluted earnings per share since their inclusion would have been antidilutive.

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

Prior to February 2005, Grey Wolf Exploration Inc. was a wholly-owned Canadian subsidiary of Abraxas. In February 2005, Grey Wolf closed on an initial public offering resulting in the substantial divestiture of our capital stock in Grey Wolf. As a result of the Grey Wolf IPO, and the significant divestiture of our interest in Grey Wolf, the results of operations of Grey Wolf are reflected in our Financial Statements and in this document as "Discontinued Operations" and our remaining operations are referred to in our Financial Statements and in this document as "Continuing Operations" or "Continued Operations". Unless otherwise noted, all disclosures are for continuing operations.

The following is a discussion of our consolidated financial condition, results of continuing 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.

General

We are an independent energy company primarily engaged in the development, and production of natural gas and crude oil. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a substantial inventory of development opportunities, which provide a basis for significant production and reserve increases. In addition, we intend to expand upon our exploitation and development activities with complementary exploration projects in our core areas of operation.

We have incurred net losses in two of the last five years, and there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors which significantly affect our results of operations including the following:

- the sales prices of natural gas and crude oil ;
- the level of total sales volumes of natural gas, natural gas liquids and crude oil;
- the availability of, and our ability to raise additional capital resources and provide liquidity to meet, cash flow needs;

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- the level of and interest rates on borrowings; and
- the level and success of exploitation, exploration and development activity.

Commodity Prices and Hedging Activities. 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 January 2001, our realized price for natural gas sales 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 2005. Prices have continued to remain strong during the beginning of 2006 compared to historical levels, but have weakened from levels during the latter part of 2005 and early 2006. If prices continue to weaken, our cash flow from operations will be adversely affected.

The table below illustrates how natural gas prices have fluctuated over the eight quarters prior to and including the quarter ended December 31, 2005 and contains the last three day average of NYMEX traded contracts price and the prices we realized during each quarter presented, including the impact of our hedging activities.

Natural Gas Prices by Quarter (in $ per Mcf)

	Quarter Ended					
	Mar. 31, 2004	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005	June 30, 2005
Index	$5.69	$5.97	$5.85	$6.77	$6.30	$ 6.80
Realized	$4.98	$5.52	$5.24	$6.14	$5.26	$ 6.33

The NYMEX natural gas price on March 21, 2006 was $6.87 per Mcf.

The table below illustrates how crude oil prices have fluctuated over the eight quarters prior to and including the quarter ended December 31, 2005 and contains the last three day average of NYMEX traded contracts price and the prices we realized during each quarter presented, including the impact of our hedging activities.

Crude Oil Prices by Quarter (in $ per Bbl)

	Quarter Ended					
	Mar. 31, 2004	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005	June 30, 2005
Index	$34.76	$38.48	$42.32	$49.46	$47.33	$ 51.76
Realized	$34.18	$37.29	$42.43	$46.81	$47.13	$ 49.43

The NYMEX crude oil price on March 21, 2006 was $60.57 per Bbl.

We seek to reduce our exposure to price volatility by hedging our production primarily through price floors. In 2003 and 2005, we incurred hedging cost of $842,000 and $592,000, respectively. For the year ended December 31, 2004, we recognized a gain from hedging activities of approximately $118,000.

Under the terms of our revolving credit facility, we are required to maintain hedging positions with respect to not less than 25% nor more than 75% of our natural gas and crude oil production, on an equivalent basis, for a rolling six month period. We currently have the following hedges in place:

Time Period	Notional Quantities	Price
April 2006	10,000 MMbtu of production per day	Floor of $7.00
May 2006	10,000 MMbtu of production per day	Floor of $8.00
June 2006	10,000 MMbtu of production per day	Floor of $8.00

July 2006	10,000 MMbtu of production per day	Floor of $7.00

August 2006	10,000 MMbtu of production per day	Floor of $6.00
September 2006	10,000 MMbtu of production per day	Floor of $5.00

At December 31, 2005 the aggregate fair market value of our hedges was approximately $76,000.

Production Volumes. Because our proved reserves will decline as natural gas, natural gas liquids and crude oil are produced, unless we acquire additional properties containing proved reserves or conduct successful exploitation 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 and development projects.

We had capital expenditures for 2005 of $35 million and have budgeted approximately $40 million in 2006. Capital spending limitations that existed under the terms of our prior senior credit agreement and our 11 1/2% notes due 2007 were removed in connection with the refinancing that closed in October 2004. As a result of the limitations, we were limited for most of 2004 in our ability to replace existing production with new production. 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.

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital going forward will primarily be cash from operating activities, funding under our revolving credit facility, cash on hand, and if an appropriate opportunity presents itself, proceeds from the sale of properties. We currently have approximately $9.2 million of availability under our revolving credit facility. We may also seek equity capital in order to fund our planned drilling expenditures.

Exploitation and Development Activity. We believe that our high quality asset base, high degree of operational control and large inventory of drilling projects position us for future growth. Our properties are concentrated in locations that facilitate substantial economies of scale in drilling and production operations and more efficient reservoir management practices. We operate 95% of the properties accounting for approximately 94% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. In addition, we have 53 proved undeveloped projects and have identified over 184 drilling and recompletion opportunities on our existing acreage, the successful development of which we believe could significantly increase our daily production and proved reserves.

Our future natural gas and crude oil production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our natural gas and crude oil properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploitation activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploitation and development activities will result in increases in our proved reserves. In addition, approximately 52% of our total estimated proved reserves at December 31, 2005 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. For a more complete discussion of these risks please see "Risk Factors--We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition would be adversely affected."

Borrowings and Interest. We currently have indebtedness of approximately $130.8 million and availability of $9.2 million under the revolving credit facility. We paid interest under our 11 1/2% secured notes due 2007 by the issuance of additional notes, which resulted in our interest paid in cash to be $7.6 million during 2004. In connection with the refinancing transactions completed in October 2004, interest on the notes, unlike interest on the notes which were repaid in 2004, is paid in cash. Cash interest expense was $14.0 million during 2005 and based on current interest rates and our outstanding indebtedness at March 13, 2006, would be approximately $15.6 million for 2006. This increase in cash interest expense has required us to increase our production and cash flow from operations in order to meet our debt service requirements, as well as to fund the development of our numerous drilling opportunities.

Outlook for 2006. As a result of final 2005 financial results and current market conditions, we have updated our operating and financial guidance for year 2006 as follows:

Production:	
BCFE (approximately 80% gas)......................	7.5 - 8.5
Exit Rate (Mmcfe/d).................................	22 - 24
Price Differentials (Pre Hedge):	
Gas (% Mcf).......................................	5%
Oil ($/Bbl).......................................	1.00
Production taxes (% of Revenue)	10%
Direct Lease Operating Expenses ($/ Mcfe)............	1.10
G&A ($/ Mcfe)..	0.55
Interest ($/Mcfe)....................................	2.00
DD&A ($/Mcfe)..	1.50
Capital Expenditures ($ Millions)....................	40.0

Results of Operations

Selected Operating Data. The following table sets forth certain of our operating data for the periods presented. All data has been restated to reflect continuing operations.

	Years Ended December 31 (dollars in thousands, except per unit d		
	2005	2004	
Operating revenue(1):			
Crude oil sales............................	$ 10,354	$ 8,843	$
NGLs sales	-	234	
Natural gas sales..........................	36,960	23,996	
Rig and other..............................	1,311	781	
Total operating revenues	$ 48,625	$ 33,854	$

Operating income (2)......................	$	22,104	$	12,165	$
Crude oil production (MBbls)...............		194.4		220.4	
NGLs production (MBbls)....................		-		8.9	
Natural gas production (MMcf)..............		4,942.4		4,403.0	
Average crude oil sales price (per Bbl)	$	53.27	$	40.12	$
Average NGLs sales price (per Bbl)	$	-	$	26.32	$
Average natural gas sales price (per Mcf)	$	7.48	$	5.45	$

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(1) Revenue and average sales prices are net of hedging activities.

(2) Operating income for 2004 and 2003 reflect the retrospective adoption of SFAS No. 123R "Share-Based Payment"

Comparison of Year Ended December 31, 2005 to Year Ended December 31, 2004

Operating Revenue. During the year ended December 31, 2005, operating revenue from natural gas and crude oil sales increased by $14.2 million from $33.1 million in 2004 to $47.3 million in 2005. The increase in revenue was primarily due to increased commodity prices realized in 2005 as compared to 2004, as well as an increase in natural gas production volumes. Higher commodity prices contributed $12.6 million to natural gas and crude oil revenue while increased production volumes contributed $1.6 million to revenue.

In prior years we were being paid on certain wells for the natural gas liquid content of the gas as a separate component as well as the value of the residue gas after processing. In 2005 we elected to be paid for this natural gas at the wellhead. Accordingly, we did not recognize any natural gas liquids

revenue in 2005. Crude oil sales volumes decreased slightly from 220.4 MBbls in 2004 to 194.4 MBbls during 2005. The decrease is primarily due to natural field declines. In late 2005, we drilled four additional crude oil wells in Wyoming. These wells are currently in various stages of completion, testing and stimulation. Natural gas sales volumes increased from 4.4 Bcf in 2004 to 4.9 Bcf in 2005. This increase is primarily due to new production during 2005 offset by natural field declines. New production brought on line at various times during 2005 contributed 1.1 Bcf to natural gas production and was partially offset by natural field decline.

Average sales prices in 2005 net of hedging costs were:

- $53.27 per Bbl of crude oil,
- $ 7.48 per Mcf of natural gas.

Average sales prices in 2004 net of hedging costs were:

- $40.12 per Bbl of crude oil,
- $26.32 per Bbl of natural gas liquids, and
- $ 5.45 per Mcf of natural gas.

Lease Operating Expense and Production Taxes. Lease operating expense, or LOE, increased from $8.6 million in 2004 to $11.1 million in 2005. The increase in LOE was primarily due to higher production taxes associated with higher commodity prices in 2005 as compared to 2004 as well as a general increase in the cost of field services and the amount of services required by us as we increased our drilling activity during 2005 as compared to 2004. Our LOE on a per Mcfe basis for the year ended December 31, 2005 was $1.82 per Mcfe compared to $1.48 per Mcfe in 2004. The increase on a per Mcfe basis was due to increased cost in 2005 as compared to 2004.

G&A Expense. G&A expense increased from $5.1 million in 2004 to $5.5 million in 2005. The increase in G&A expense in 2005 was primarily due to higher performance bonuses in 2005 as compared to 2004. Our G&A expense on a per Mcfe basis increased from $0.89 in 2004 to $0.90 in 2005. The increase in the per Mcfe cost was due to increased expense in 2005 as compared to 2004.

Stock-based Compensation. 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 on all options with an existing exercise price greater than $2.06 to $2.06. In January 2003, we amended the exercise price to $0.66 per share on certain options with an existing exercise price greater than $0.66 per share which resulted in variable accounting treatment on these options. Under the rules of variable accounting, we recognized the difference in the market price of our common stock as of the end of the period and the exercise price of $0.66. Subsequently, if the market price of our common stock increased from the previous period, we recognized expense; conversely, if the price decreased we recognized a gain. Prior to the adoption of SFAS No.123R, as discussed below, we had charged approximately $1.3 million to stock based compensation expense in 2004 related to these repricings.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". SFAS No. 123R is a revision of SFAS No. 123, "Accounting for Stock Based Compensation", and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. In December 2005, we elected early adoption of SFAS 123R.

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS

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123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS 123. We elected to use the "modified retrospective" method, and have accordingly restated prior year financial statements to reflect this method.

As a result of the retrospective adoption of SFAS 123R, the expenses previously recognized under the rules of variable accounting were reversed and a compensation expense measured according to SFAS 123R was recorded. As a result, we recognized stock-based compensation of $247,000 during 2005 as a result of the adoption of this accounting change compared to $112,000 in 2004, as restated.

We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees. While SFAS 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or "lattice" model. Based upon research done by us on the alternative models available to value option grants, and in conjunction with the type and number of stock options expected to be issued in the future, we have determined that we will continue to use the Black-Scholes model for option valuation as of the current time.

DD&A Expense. Depreciation, depletion and amortization expense increased from $7.2 million in 2004 to $8.9 million in 2005. The increase in DD&A was primarily due to increased production volumes in 2005 and increased capital expenditures in 2005 as compared to 2004. Our DD&A expense on a per Mcfe basis for 2005 was $1.46 per Mcfe as compared to $1.25 per Mcfe in 2004.

Interest Expense. Interest expense decreased from $17.9 million to $14.0 million for 2005 compared to 2004. The decrease in interest expense was due to decreased debt levels during 2005. While the outstanding debt at December 31, 2005 was slightly higher than the balance as December 31, 2004, the level of debt during the course of 2004, prior to the financial restructuring that occurred in October 2004, was significantly higher. In addition, during most of 2004, interest on our then outstanding secured notes was payable by the issuance of additional notes, which caused our cash interest expense in 2004 to be $7.6 million. With the issuance of the notes in October 2004, interest is payable in cash, which led to all of the interest paid in 2005 being paid in cash.

Financing Costs. Financing costs in 2004 were $1.7 million compared to zero in 2005. Financing costs represent costs related to refinancing activities, which do not qualify for amortization over the life of the debt. The 2004 costs relate to the refinancing activities during 2004. We did not undertake any refinancing activities in 2005.

Income from discontinued operations. Income from discontinued operations was $12.8 million in 2005 compared to $3.3 million in 2004. On February 28, 2005, Grey Wolf Exploration Inc. completed an IPO resulting in Abraxas substantially divesting itself of its investment in Grey Wolf. The operations of Grey Wolf, previously reported as a business segment, are reported as discontinued operations for all periods presented in the accompanying financial statements and the operating results are reflected separately from the results of continuing operations.

Income from discontinued operations for the period ended December 31, 2005 includes a gain on the disposal of Grey Wolf of $17.3 million, net of non-cash income tax of $6.1 million, and a loss from operations, including debt retirement costs, of $4.4 million. Income from discontinued operations for the year ended December 31, 2004 represents the operating results of Grey Wolf for the year then ended.

Comparison of Year Ended December 31, 2004 to Year Ended December 31, 2003

Operating Revenue. During the year ended December 31, 2004, operating revenue from crude oil, natural gas and natural gas liquids sales increased by $3.4 million from $29.7 million in 2003 to $33.1 million in 2004. The increase in revenue was primarily due to increased commodity prices realized in 2004 as compared to 2003. The increase in revenue due to commodity prices was partially offset by decreased production volumes. Higher commodity prices contributed $5.2 million to natural gas and crude oil revenue while reduced production volumes had a $1.8 million negative impact on revenue.

Natural gas liquids volumes declined from 9.4 MBbls in 2003 to 8.9 MBbls in 2004. Crude oil sales volumes increased slightly from 220.1 MBbls in 2003 to 220.4 MBbls during 2004. The increase is primarily due to the production from new wells in Wyoming and west Texas brought onto production in 2004, offsetting natural field declines in other areas. Natural gas sales volumes decreased from 4.8 Bcf in 2003 to 4.4 Bcf in 2004. This decrease is primarily due to natural field declines. There were no significant wells brought on line in 2004, primarily due to significant restrictions on capital expenditures for most of the year.

Average sales prices in 2004 net of hedging costs were:

- $40.12 per Bbl of crude oil,
- $26.32 per Bbl of natural gas liquids, and
- $ 5.45 per Mcf of natural gas.

Average sales prices in 2003 net of hedging costs were:

- $30.43 per Bbl of crude oil,
- $20.46 per Bbl of natural gas liquids, and
- $ 4.77 per Mcf of natural gas.

Lease Operating Expense. Lease operating expense, or LOE, increased slightly from $8.3 million in 2003 to $8.6 million in 2004. The increase in LOE was primarily due to higher production taxes associated with higher commodity prices in 2004 as compared to 2003. Our LOE on a per Mcfe basis for the year ended December 31, 2004 was $1.48 per Mcfe compared to $1.35 for 2003, primarily due to the decrease in production volumes.

G&A Expense. G&A expense increased from $4.0 million in 2003 to $5.1 million in 2004. The increase in G&A expense was primarily due to performance bonuses in 2004. Our G&A expense on a per Mcfe basis increased from $0.65 in 2003 to $0.89 in 2004. The increase in the per Mcfe cost was due to increased expense and to lower production volumes in 2004 as compared to 2003.

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 on all options with an existing exercise price greater than $2.06 to $2.06. In January 2003, we amended the exercise price to $0.66 per share on certain options with an existing exercise price greater than $0.66 per share which resulted in variable accounting treatment on these options. Under the rules of variable accounting, we recognized the difference in the market price of our common stock as of the end of the period and the exercise price of $0.66. Subsequently, if the market price of our common stock increased from the previous period, we recognized expense; conversely, if the price decreased, we recognized a gain. Prior to the adoption of SFAS No. 123R, as discussed below, we had charged approximately $1.3 million to stock based compensation expense in 2004 related to these repricings.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". SFAS No. 123R is a revision of SFAS No. 123, "Accounting for Stock Based Compensation", and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. In December 2005, we elected early adoption of SFAS 123R.

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS

123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS 123. We elected to use the "modified retrospective" method, and have accordingly restated prior year financial statements to reflect this method.

As a result of the retrospective adoption of SFAS 123R, the expenses previously recognized under the rules of variable accounting were reversed and a compensation expense measured according to SFAS 123R was recorded. As a result, we recognized a reduction of stock-based compensation of $1.2 million during 2004 as a result of the adoption of this accounting change. Restated stock-based compensation expense was $228,000 and $112,000 for 2003 and 2004, respectively.

We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to Employees. While SFAS 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or "lattice" model. Based upon research done by us on the alternative models available to value option grants, and in conjunction with the type and number of stock options expected to be issued in the future, we have determined that we will continue to use the Black-Scholes model for option valuation as of the current time.

DD&A Expense. Depreciation, depletion and amortization expense decreased from $7.6 million in 2003 to $7.2 million in 2004. The decrease in DD&A was primarily due to decreased production volumes in 2004. Our DD&A expense on a per Mcfe basis for 2004 was $1.25 per Mcfe as compared to $1.24 per Mcfe in 2003.

Interest Expense. Interest expense increased from $16.3 million to $17.9 million for 2004 compared to 2003. The increase in interest expense was due to increased debt levels in 2004, prior to the refinancing completed in October 2004. The increase in debt was primarily due to the payment of interest by the issuance of additional notes pursuant to the 11 1/2% notes due 2007, which were repaid in October 2004. Cash interest expense was $7.6 million in 2004 and $3.6 million in 2003.

Financing Costs. Financing costs in 2004 were $1.7 million compared to $4.4 million in 2003. Financing costs represent costs related to refinancing activities, which do not qualify for amortization over the life of the debt. Financing costs in 2003 were related to the restructuring transaction, which occurred in January 2003. The 2004 costs relate to the refinancing activities during 2004.

Income from discontinued operations. Income from discontinued operations was $3.3 million in 2004 compared to $70.0 million in 2003. This represents income from Grey Wolf, which was sold in February 2005. Income in

2003 included a gain on the sale of foreign subsidiaries in January 2003 of $68.9 million. Excluding this gain, income in 2003 would have been $1.1 million. The increase in income in 2004, exclusive of the gain, was due to increased production and higher commodity prices in 2004 as compared to 2003.

Liquidity and Capital Resources

General. The natural gas and crude oil 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 additional natural gas and crude oil properties; and
- production and transportation facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our 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 going forward will primarily be cash from operating activities, funding under our revolving credit facility, and if an appropriate opportunity presents itself, proceeds from the sale of properties. We may also seek equity capital although we may not be able to complete any equity financings on terms acceptable to us, if at all. In addition, under the terms of the notes, proceeds of optional sales of our assets that are not timely reinvested in new natural gas and crude oil assets will be required to be used to reduce indebtedness and proceeds of mandatory sales must be used to repay or redeem indebtedness.

Working Capital (Deficit). The following discussion represents working capital from continuing operations. At December 31, 2005 our current liabilities of approximately $15.2 million exceeded our current assets of $10.3 million resulting in a working capital deficit of $4.9 million. This compares to a working capital deficit of $4.6 million as of December 31, 2004. Current liabilities as of December 31, 2005 consisted of trade payables of $9.8 million, revenues due third parties $3.5 million, accrued interest of $1.4 million and other accrued liabilities of $ 0.5 million.

Capital Expenditures. Capital expenditures related to our continuing operations in 2005, 2004 and 2003 were $35.4 million, $9.3 million and $9.2 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2005.

	Year Ended December 31		
	2005	2004	2003
	(dollars in thousands)		
Expenditure category:			
Development	$ 34,991	$ 9,088	$ 9,158
Facilities and other	359	181	36

Total	$ 35,350	$ 9,269	$ 9,194

During 2005, 2004 and 2003, capital expenditures were primarily for the development of existing properties. We anticipate making capital expenditures for 2006 of approximately $40.0 million which will be used primarily for the development of our current properties. These anticipated expenditures are subject to adequate cash flow from operations and availability under our revolving credit facility. If these sources of funding do not prove to be sufficient, we may also issue additional shares of equity securities although we may not be able to complete equity financings on terms acceptable to us, if at all. Our ability to make all of our budgeted capital expenditures will also be subject to availability of drilling rigs and other field equipment and services. Our capital expenditures could also 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 natural gas and crude oil continue to decline and if our costs of operations continue to increase as a result of the scarcity of drilling rigs or if our production volumes decrease, 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 natural gas and crude oil production volumes decreases caused by natural field declines and sales of producing properties, if any.

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

	Year Ended December 31,		
	2005	2004	2003
	(dollars in thousands)		
Net cash provided by operating activities	$ 21,099	$ 27,000	$ 11,4
Net cash used in investing activities	(35,350)	(9,269)	(9,1
Net cash provided by (used in) financing activities	14,877	(65,684)	(88,6
Total	$ 626	$ (47,953)	$ (86,3

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Operating activities for the year ended December 31, 2005 provided us with $21.1 million of cash. Expenditures in 2005 of approximately $35.4 were primarily for the development of natural gas and crude oil properties. Financing activities provided $14.9 million during 2005, of which $11.3 million was provided by a private placement of common stock, $28.4 million was provided from long-term borrowing offset by $25.3 million of payments on long-term debt.

Operating activities for the year ended December 31, 2004 provided us with $27.0 million of cash. Investing activities used $9.3 million during 2004 primarily for the development of natural gas and crude oil properties. Financing activities used $65.7 million during 2004, primarily for payments on long-term debt and deferred financing fees.

Operating activities for the year ended December 31, 2003 provided us with $11.5 million of cash. Investing activities used $9.2 million during 2003. Financing activities used $88.7 million during 2003. Most of these funds were used to reduce our long-term debt and were generated by the sale of our Canadian subsidiaries and an exchange offer completed in January 2003. The sale of our Canadian subsidiaries contributed $85.8 million in 2003 reduced by $9.2 million in exploitation and development expenditures. Expenditures in 2003 were primarily for the development of natural gas and crude oil properties.

Future Capital Resources. We currently have three principal sources of liquidity going forward: (i) cash from operating activities, (ii) funding under our revolving credit facility, and (iii) if an appropriate opportunity presents itself, the sale of producing properties. If these sources of liquidity do not prove to be sufficient, we may also issue additional shares of equity securities although we may not be able to complete equity financings on terms acceptable to us, if at all. While we are no longer subject to limitations on capital expenditures under our 11 1/2% secured notes due 2007, covenants under the indenture for the notes and the revolving credit facility restrict our use of cash from operating activities, cash on hand and any proceeds from asset sales. Under the terms of the notes, proceeds of optional sales of our assets that are not timely reinvested in new natural gas and crude oil assets will be required to be used to reduce indebtedness and proceeds of mandatory sales must be used to redeem indebtedness. The terms of the notes and the revolving credit facility also substantially restrict our ability to:

- incur additional indebtedness;
- grant liens;
- pay dividends or make certain other restricted payments;
- 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 cash flow from operations depends heavily on the prevailing prices of natural gas and crude oil and our production volumes of natural gas and crude oil. Although we have hedged a portion of our natural gas and crude oil production and will continue this practice as required pursuant to the revolving credit facility, future natural gas and crude oil price declines would have a material adverse effect on our overall results, and therefore, our liquidity. Low natural gas and crude oil prices could also negatively affect our ability to raise capital on terms favorable to us or at all.

Our cash flow from operations will also depend upon the volume of natural gas and crude oil that we produce. Unless we otherwise expand reserves, our production volumes may decline as reserves are produced. Due to sales of properties in 2002 and 2003 and the divestiture of Grey Wolf during the first quarter of 2005, and restrictions on capital expenditures under the terms of our 11 1/2% secured notes due 2007 (which were refinanced in October 2004), we now have significantly reduced reserves and production as compared with pre-2003 levels. In the future, if an appropriate opportunity presents itself, 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, exploitation, exploration and development activities, acquire additional producing properties or identify additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive natural gas or crude oil reservoirs will be found. The risk of not finding commercially productive reservoirs will be compounded by the fact that 52% of our total estimated proved

reserves at December 31, 2005 were undeveloped. During 2005, we expended approximately $35.0 million for twelve wells in south Texas, west Texas and Wyoming. We are currently completing and/or testing multiple Woodford, Atoka and Wolfcamp wells in west Texas and continue to recomplete various wells in South Texas. In the latter part of the year we drilled and are currently completing and testing four vertical wells in Wyoming. . In addition, approximately 30% of our production at March 13, 2006 was from a single well in west Texas. If production from this well decreases, the volume of our production would also decrease which, in turn, would likely cause our cash flow from operations to decrease.

Our total indebtedness and cash interest expense as a result of issuing the notes and entering into the revolving credit facility require us to increase our production and cash flow from operations in order to meet our debt service requirements, as well as to fund the development of our numerous drilling opportunities. The ability to satisfy these new obligations will depend upon our drilling success as well as prevailing commodity prices.

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

- Long-term debt
- 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, 2005.

	Payments due in:				
Contractual Obligations (dollars in thousands)	Total	2006	2007-2008	2009-2010	The
Long-Term Debt (1)	$ 129,527	$ -	$ 4,527	$ 125,000	$
Interest on long-term debt (2)	60,200	15,473	30,885	13,842	
Operating Leases (3)	780	254	505	21	
Total	$ 190,507	$ 15,727	$ 35,917	$ 138,863	$

(1) These amounts represent the balances outstanding under the revolving credit facility and the notes. These repayments assume that we will not draw down additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the

period and current effective interest rates.

(3) Office lease obligations. The lease for office space expires in January 2009.

Contingencies.

From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2005 we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, exploitation development 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 following table sets forth our long-term indebtedness as of December 31, 2005 and 2004.

Long Term Indebtedness

	December 31,	
	2005	2004
	(in thousands)	
Floating rate senior secured notes due 2009......................	$ 125,000	$ 125,0
Senior secured revolving credit facility.........................	4,527	1,4
	129,527	126,4
Less current maturities	-	
	$ 129,527	$ 126,4

Floating Rate Senior Secured Notes due 2009. In connection with the October 2004 financial restructuring, Abraxas issued $125 million in principal aggregate amount of Floating Rate Senior Secured Notes due 2009. The notes will mature on December 1, 2009 and began accruing interest from the date of issuance, October 28, 2004, at a per annum floating rate of six-month LIBOR plus 7.50%. The initial interest rate on the notes was 9.72% per annum. The interest will be reset semi-annually on each June 1 and December 1, commencing on June 1, 2005. The current interest rate is 12.08% per annum. Interest is payable semi-annually in arrears on June 1 and December 1 of each year, commencing on June 1, 2005.

The notes rank equally among themselves and with all of our unsubordinated and unsecured indebtedness, including our revolving credit facility and senior in right of payment to our existing and future subordinated indebtedness.

Each of our subsidiaries, Eastside Coal Company, Inc., Sandia Oil & Gas Corporation, Sandia Operating Corp., Wamsutter Holdings, Inc. and Western Associated Energy Corporation (collectively, the "Subsidiary Guarantors"), has unconditionally guaranteed, jointly and severally, the payment of the principal, premium and interest including any additional interest on, the notes on a senior secured basis. In addition, any other subsidiary or affiliate of ours, that in the future guarantees any other indebtedness with us, or our restricted subsidiaries, will also be required to guarantee the notes.

The notes and the Subsidiary Guarantors' guarantees thereof, together with our revolving credit facility and the Subsidiary Guarantors' guarantees thereof, are secured by shared first priority perfected security interests, subject to certain permitted encumbrances, in all of our and each of our restricted subsidiaries' material property and assets, including substantially all of our and their natural gas and crude oil properties and all of the capital stock (or in the case of an unrestricted subsidiary that is a controlled foreign corporation, up to 65% of the outstanding capital stock) of any entity, owned by us and our restricted subsidiaries (collectively, the "Collateral").

The notes may be redeemed, at our election, as a whole or from time to time in part, at any time after April 28, 2007, upon not less than 30 nor more that 60 days' notice to each holder of notes to be redeemed, subject to the conditions and at the redemption prices (expressed as percentages of principal amount) set forth below, together with accrued and unpaid interest and Liquidating Damages, if any, to the applicable redemption date.

Year	Percentage
From April 29, 2007 to April 28, 2008	104.00%
From April 29, 2008 to April 28, 2009	102.00%
After April 28, 2009	100.00%

Prior to April 28, 2007, we may redeem up to 35% of the aggregate original principal amount of the notes using the net proceeds of one or more equity offerings, in each case at the redemption price equal to the product of (i) the principal amount of the notes being so redeemed and (ii) a redemption price factor of 1.00 plus the per annum interest rate on the notes (expressed as a decimal) on the applicable redemption date plus accrued and unpaid interest to the applicable redemption date, provided certain conditions are also met.

If we experience specific kinds of change of control events, each holder of notes may require us to repurchase all or any portion of such holder's notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of repurchase.

The indenture governing the notes contains covenants that, among other things, limit our ability to:

- o incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- o transfer or sell assets;
- o create liens on assets;
- o pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- o engage in transactions with affiliates;

- guarantee other indebtedness;
- permit restrictions on the ability of our subsidiaries to distribute or lend money to us;
- cause a restricted subsidiary to issue or sell its capital stock; and
- consolidate, merge or transfer all or substantially all of the consolidated assets of our and our restricted subsidiaries.

The indenture also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, including our new credit facility and bridge loan, bankruptcy, and material judgments and liabilities.

Senior Secured Revolving Credit Facility. On October 28, 2004, we entered into an agreement for a revolving credit facility having a maximum commitment of $15 million, which includes a $2.5 million subfacility for letters of credit. Availability under the revolving credit facility is subject to a borrowing base consistent with normal and customary natural gas and crude oil lending transactions.

Outstanding amounts under the revolving credit facility bear interest at the prime rate announced by Wells Fargo Bank, National Association plus 1.00%. Subject to earlier termination rights and events of default, the stated maturity date under the revolving credit facility is October 28, 2008.

We are permitted to terminate the revolving credit facility, and under certain circumstances, may be required, from time to time, to permanently reduce the lenders' aggregate commitment under the revolving credit facility. Such termination and each such reduction is subject to a premium equal to the percentage listed below multiplied by the lenders' aggregate commitment under the revolving credit facility, or, in the case of partial reduction, the amount of such reduction.

Year	% Premium
1	1.5
2	1.0
3	0.5
4	0.0

Each of our current subsidiaries has guaranteed, and each of our future restricted subsidiaries will guarantee, our obligations under the revolving credit facility on a senior secured basis. In addition, any other subsidiary or affiliate of ours, that in the future guarantees any of our other indebtedness or of its restricted subsidiaries will be required to guarantee our obligations under the revolving credit facility. Obligations under the revolving credit facility are secured, together with the notes, by a shared first priority perfected security interest, subject to certain permitted encumbrances, in all of our and each of our restricted subsidiaries' material property and assets, including substantially all of our and their natural gas and crude oil properties and all of the capital stock (or in the case of an unrestricted subsidiary that is a controlled foreign corporation, up to 65% of the outstanding capital stock) in any entity, owned by us and our restricted subsidiaries.

Under the revolving credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. The revolving credit facility requires us to maintain a minimum net cash interest coverage and also requires us to enter into hedging agreements on not less than

25% or more than 75% of our projected natural gas and crude oil production.

In addition to the foregoing and other customary covenants, the revolving credit facility contains a number of covenants that, among other things, restrict Abraxas' ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- make any change in the principal nature of our business;
- prepay, redeem, purchase or otherwise acquire any of our or our restricted subsidiaries' indebtedness;
- permit a change of control;
- directly or indirectly make or acquire any investment;
- cause a restricted subsidiary to issue or sell our capital stock; and
- consolidate, merge or transfer all or substantially all of the consolidated assets of Abraxas and our restricted subsidiaries.

The revolving credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities, and is subject to an Intercreditor, Security and Collateral Agency Agreement, which specifies the rights of the parties thereto to the proceeds from the Collateral.

Intercreditor Agreement. The holders of the notes, together with the lenders under our revolving credit facility, are subject to an Intercreditor, Security and Collateral Agency Agreement, which specifies the rights of the parties thereto to the proceeds from the Collateral. The Intercreditor Agreement, among other things, (i) creates security interests in the Collateral in favor of a collateral agent for the benefit of the holders of the notes and the credit facility lenders and (ii) governs the priority of payments among such parties upon notice of an event of default under the indenture or the revolving credit facility.

So long as no such event of default exists, the collateral agent will not collect payments under the credit facility documents or the indenture governing the notes and other note documents (collectively, the "Secured Documents"), and all payments will be made directly to the respective creditor under the applicable Secured Document. Upon notice of an event of default and for so long as an event of default exists, payments to each credit facility lender and holder of the notes from us and our current subsidiaries and proceeds from any disposition of any collateral, will, subject to limited exceptions, be collected by the collateral agent for deposit into a collateral account and then distributed as provided in the following paragraph.

Upon notice of any such event of default and so long as an event of default exists, funds in the collateral account will be distributed by the collateral agent generally in the following order of priority:

first, to reimburse the collateral agent for expenses incurred in protecting and realizing upon the value of the Collateral;

second, to reimburse the credit facility administrative agent and the trustee, on a pro rata basis, for expenses incurred in protecting and realizing upon the value of the Collateral while any of these parties was acting on behalf of the Control Party (as defined below);

third, to reimburse the credit facility administrative agent and the trustee, on a pro rata basis, for expenses incurred in protecting and realizing upon the value of the Collateral while any of these parties was not acting on behalf of the Control Party;

fourth, to pay all accrued and unpaid interest (and then any unpaid commitment fees) under the credit facility;

fifth, if the collateral coverage value of three times the outstanding obligations under the credit facility would be met after giving effect to any payment under this clause "fifth," to pay all accrued and unpaid interest on the notes;

sixth, to pay all outstanding principal of (and then any other unpaid amounts, including, without limitation, any fees, expenses, premiums and reimbursement obligations) the credit facility;

seventh, to pay all accrued and unpaid interest on the notes (if not paid under clause "fifth");

eighth, to pay all outstanding principal of (and then any other unpaid amounts, including, without limitation, any premium with respect to) the notes; and

ninth, to pay each credit facility lender, holder of the notes, and other secured parties, on a pro rata basis, all other amounts outstanding under the credit facility and the notes.

To the extent there exists any excess monies or property in the collateral account after all of our and our subsidiaries' obligations under the credit facility, the indenture and the notes are paid in full, the collateral agent will be required to return such excess to us.

The collateral agent will act in accordance with the Intercreditor Agreement and as directed by the "Control Party" which for purposes of the Intercreditor Agreement is the holders of the notes and the credit facility lenders, acting as a single class, by vote of the holders of a majority of the aggregate principal amount of outstanding obligations under the notes and the credit facility.

The Intercreditor Agreement provides that the lien on the assets constituting part of the Collateral that is sold or otherwise disposed of in accordance with the terms of each Secured Document may be released if (i) no default or event of default exists under any of the Secured Documents, (ii) we have delivered an officers' certificate to each of the collateral agent, the trustee, the credit facility administrative agent certifying that the proposed sale or other disposition of assets is either permitted or required by, and is in accordance with the provisions of, the applicable Secured Documents and (iii) the collateral agent has acknowledged such certificate.

The Intercreditor Agreement provides for the termination of security interests on the date that all obligations under the Secured Documents are paid in full.

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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 our revolving credit facility, we are required to 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. See "--Quantitative and Qualitative Disclosures about Market Risk--Hedging Sensitivity" for further information.

Net Operating Loss Carryforwards

At December 31, 2005, we had, subject to the limitation discussed below, $190.0 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2025 if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, we have established a valuation allowance of $73.0 million and $67.0 million for deferred tax assets at December 31, 2004 and 2005, respectively.

Related Party Transactions

Abraxas has adopted a policy that transactions between Abraxas and its officers, directors, principal stockholders, or affiliates of any of them, will be on terms no less favorable to Abraxas than can be obtained on an arm's length basis in transactions with third parties and must be approved by the vote of at least a majority of the disinterested directors.

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 natural gas and crude oil activities. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in natural gas and crude oil activities. Two methods are prescribed: the successful efforts method and the full cost method. We have chosen to follow the full cost method under which all costs associated with property acquisition, exploitation and development are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploitation 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 natural gas and crude oil 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 natural gas and crude oil 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 rate on our natural gas and crude oil 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 recoverable when prices return to higher levels. We have experienced this situation several times over the years, most recently in 2002. Our natural gas and crude oil 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 natural gas and crude oil properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves

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on a pool by pool basis, discounted at 10%, plus the lower of cost or fair market value of unproved properties and the cost of properties not being amortized, less income taxes. If net capitalized costs of natural gas and crude oil 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 natural gas and crude oil properties increases when natural gas and crude oil 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 natural gas and crude oil prices may have increased the ceiling applicable to the subsequent period.

For the year ended December 31, 2002, we recorded a ceiling limitation write-down due to low commodity prices. We cannot assure you that we will not experience additional write-downs in the future.

Estimates of Proved Natural Gas and Crude Oil Reserves. 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.

Our 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, we 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 we record 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.

Asset Retirement Obligations. The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is 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. 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.

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

Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities", was effective for us 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. In 2003 we elected out of hedge accounting as prescribed by SFAS 133.

Accordingly all derivatives, whether designated in hedging relationships or not, are required to be recorded at fair value on our balance sheet. Changes in fair value of contracts are recognized in earnings in the current period.

Due to the volatility of natural gas and crude oil 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, 2005 and 2004 the net market value of our derivatives was an asset of $75,817 and $528,165 respectively.

Share-Based Payments. In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". SFAS No. 123R is a revision of SFAS No. 123, "Accounting for Stock Based Compensation", and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. The Company has elected early adoption of SFAS 123R .

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permit entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS 123. The Company has elected to use the "modified retrospective" method. This standard requires the cost of all share-based payments, including stock options, to be measured at fair value on the grant date and recognized in the statement of operations. In accordance with this standard, all periods prior to January 1, 2005 were restated to reflect the impact of the standard as if it had been adopted on January 1, 1995, the original effective date of SFAS No. 123, "Accounting for Stock-Based Compensation". Also in accordance with the standard, the amounts that are reported in the statement of operations for the restated periods are the pro forma amounts previously disclosed under SFAS No. 123.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees. While SFAS 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or "lattice" model. Based upon research done by the Company on the alternative models available to value option grants, and in conjunction with the type and number of stock options expected to be issued in the future, the Company has determined that it will continue to use the Black-Scholes model for option valuation as of the current time.

SFAS 123R includes several modifications to the way that income taxes are recorded in the financial statements. The expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in the Company's effective tax rates recorded throughout the year. SFAS 123R does not allow companies to "predict" when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise stock options.

New Accounting Pronouncements

In March 2005 the FASB issued Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations--an interpretation of FASB Statement No. 143". This Interpretation clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred--generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. Statement 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

This Interpretation is effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application for interim financial information is permitted but is not required. Early adoption of this Interpretation is encouraged. This statement did not effect the Company's financial statements for the period ended December 31, 2005.

In May 2005, the FASB issued "Summary of Statement No. 154 Accounting Changes and Error Corrections" - a replacement of APB Opinion No. 20 and FASB Statement No. 3. This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting for and reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed.

Opinion 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. When it is impracticable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in an income statement. When it is impracticable to determine the cumulative effect of applying a change in accounting principle to all prior periods, this Statement requires that the new accounting principle be applied as if it were adopted prospectively from the earliest date practicable.

This Statement defines retrospective application as the application of a different accounting principle to prior accounting periods as if that principle had always been used or as the adjustment of previously issued financial statements to reflect a change in the reporting entity. This Statement also redefines restatement as the revising of previously issued financial statements to reflect the correction of an error.

This Statement requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in non-discretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change.

This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate effected by a change in accounting principle.

This Statement carries forward without change the guidance contained in Opinion 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate.

This Statement also carries forward the guidance in Opinion 20 requiring justification of a change in accounting principle on the basis of preferability.

This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. This statement did not effect the Company's financial statements for the period ended December 31, 2005.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent natural gas and crude oil 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 adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of natural gas and crude oil 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 natural gas and crude oil 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, 2005, a 10% decline in natural gas and crude oil, prices would have reduced our operating revenue and cash flow by approximately $4.7 million for the year.

Hedging Sensitivity

On January 1, 2001, we adopted SFAS 133 as amended by SFAS 137 and SFAS 138. Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. In 2003 we elected not to designate derivative instruments as hedges. Accordingly the instruments are recorded on the balance sheet at fair value with changes in the market value of the derivatives being recorded in current oil and gas revenue.

Under the terms of our revolving credit facility, we are required to maintain hedging positions with respect to not less than 25% nor more than 75% of our natural gas and crude oil production for a rolling six month period.

All hedge transactions are subject to our risk management policy, which has been approved by the Board of Directors.

We currently have the following hedges in place:

Time Period	Notional Quantities	Price
April 2006	10,000 MMbtu of production per day	Floor of $7.00
May 2006	10,000 MMbtu of production per day	Floor of $8.00
June 2006	10,000 MMbtu of production per day	Floor of $8.00
July 2006	10,000 MMbtu of production per day	Floor of $7.00
August 2006	10,000 MMbtu of production per day	Floor of $6.00
September 2006	10,000 Mmbtu of production per day	Floor of $5.00

At December 31, 2005 the aggregate fair market value of our hedges was approximately $76,000.

Interest rate risk

At December 31, 2005, as a result of the financial restructuring that occurred in October 2004, we had $125.0 million in outstanding indebtedness under the floating rate senior secured notes due 2009. The notes bear interest at a per annum rate of six-month LIBOR plus 7.5%. The rate is redetermined on June 1 and December 1 of each year, beginning June 1, 2005. The current rate on the notes is 12.08%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.3 million on an annual

basis. At December 31, 2005, we had $4.5 million of outstanding indebtedness under our revolving credit facility. Interest on this facility accrues at the prime rate announced by Wells Fargo Bank plus 1.00%. For every percentage point increase in the announced prime rate, our interest expense would increase by approximately $45,000 on an annual basis.

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

Item 9A. Controls and Procedures

Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, or the Exchange Act). Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Management's Annual Report on Internal Control over Financial Reporting and Attestation Report of Registered Public Accounting Firm. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management's assessment of the design and effectiveness of our internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2005. BDO Seidman, LLP, our registered public accountants, also attested to, and reported on, management's assessment of the effectiveness of internal control over financial reporting. Management's report and the independent public accounting firms attestation report are included in our 2005 Financial Statements in Item 15 under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

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 2006 Annual Meeting of Stockholders which appears therein under the captions "Election of Directors". See also the information in Item 4a of Part I of this Report.

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Audit Committee and Audit Committee Financial Expert

The Audit Committee of our board of directors consists of C. Scott Bartlett, Jr., Frank M. Burke, Paul Powell and Joseph A. Wagda. The board of directors has determined that each of the members of the Audit Committee is independent as determined in accordance with the listing standards of the American Stock Exchange and Item 7(d) (3) (iv) of Schedule 14A of the Exchange Act. In addition, the board of directors has determined that C. Scott Bartlett, Jr., as defined by SEC rules, is an audit committee financial expert.

Section 16(a) Compliance

Section 16(a) of the Exchange Act requires Abraxas directors and executive officers and persons who own more than 10% of a registered class of Abraxas equity securities to file with the Securities and Exchange Commission and the AMEX initial reports of ownership and reports of changes in ownership of Abraxas common stock. Officers, directors and greater than 10% stockholders are required by SEC regulations to furnish us with copies of all such forms they file. Based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required. We believe that all our directors and executive officers complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act during

2005.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2006 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 and Related Stockholder Matters

There is incorporated in this Item 12 by reference that portion of our definitive proxy statement for the 2006 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 2006 Annual Meeting of Stockholders which appears therein under the caption "Certain Transactions".

Item 14. Principal Accounting Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2006 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services".

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)1. Consolidated Financial Statements

(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 our 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 our 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 our 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 our Annual Report on Form 10-K filed on March 31, 1995).
4.3	Indenture dated October 28, 2004, by and among Abraxas, as Issuer; the Subsidiary Guarantors party thereto and U.S. Bank National Association, as Trustee, relating to Abraxas' Floating Rate Senior Secured Notes Due 2009. (Filed as Exhibit 4.1 to Abraxas' Current Report on Form 8-K filed on November 3, 2004).

4.4	Form of Rule 144A Global Note for Floating Rate Senior Secured Notes due 2009. (Filed as Exhibit A-1 to Exhibit 4.1 to Abraxas' Current Report on Form 8-K filed on November 3, 2004).
4.5	Form of Regulation S Global Note for Floating Rate Senior Secured Notes

due 2009. (Filed as Exhibit A-2 to Exhibit 4.1 to Abraxas' Current Report on Form 8-K filed on November 3, 2004).

4.6 Form of Accredited Investor Certificated Note for Floating Rate Senior Secured Notes due 2009. (Filed as Exhibit A-3 to Exhibit 4.1 to Abraxas' Current Report on Form 8-K filed on November 3, 2004).

*10.1 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")).

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

*10.3 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).

*10.4 Abraxas Petroleum Corporation Amended and Restated 1994 Long Term Incentive Plan. (Filed as Exhibit 10.4 to Abraxas' Registration Statement on Form S-4 filed on January 12, 2005).

*10.5 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).

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

10.7 Loan Agreement dated as of October 28, 2004 by and among Abraxas Petroleum Corporation, the Subsidiary Guarantors party thereto, Wells Fargo Foothill, Inc., as Arranger and Administrative Agent and the Lenders signatory thereto. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed November 3, 2004).

10.8 Loan Agreement dated as of October 28, 2004 by and among Abraxas Petroleum Corporation, the Subsidiary Guarantors party thereto, Guggenheim Corporate Funding, LLC, as Arranger and Administrative Agent and the Lenders signatory thereto. (Filed as Exhibit 10.3 to Abraxas' Current Report on Form 8-K filed November 3, 2004).

*10.9 Employment Agreement between Abraxas and Robert L. G. Watson. (Filed as Exhibit 10.19 to the 2000 S-1 Registration Statement).

*10.10 Employment Agreement between Abraxas and Chris E. Williford. (Filed as Exhibit 10.20 to the 2000 S-1 Registration Statement).

*10.11 Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the S-3 Registration Statement).

*10.12 Employment Agreement between Abraxas and William H. Wallace. (Filed as Exhibit 10.27 to the S-3 Registration Statement).

*10.13 Employment Agreement between Abraxas and Lee T. Billingsley. (Filed as Exhibit 10.28 to the S-3 Registration Statement).

10.14 Intercreditor, Security and Collateral Agency Agreement dated as of October 28, 2004 by and among Abraxas Petroleum Corporation, the Subsidiary Guarantors party thereto, Wells Fargo Foothill, Inc.,

	Guggenheim Corporate Funding, LLC and U.S. Bank National Association. (Filed as Exhibit 10.5 to Abraxas' Current Report on Form 8-K filed November 3, 2004).
*10.15	Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed June 6, 2005).
*10.16	Form of Stock Option Agreement under the Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed June 6, 2005).
*10.17	Abraxas Peteroleum Corporation Senior Management Incentive Bonus Plan 2006 (Filed herewith).
10.18	Common Stock Purchase Agreement made and entered into as of the 20th day of July, 2005, by and between Abraxas Petroleum Corporation and the Purchasers signatory thereto. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed July 22, 2005).
14.1	Abraxas Petroleum Corporation Code of Business Conduct and Ethics (filed herewith)
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 BDO Seidman, LLP (filed herewith)
23.2	Consent of DeGolyer and MacNaughton. (filed herewith).
31.1	Certification - Chief Executive Officer (filed herewith)
31.2	Certification - Chief Financial Officer (filed herewith)
32.1	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).
32.2	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.

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

DATED: March 22, 2006

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	March 22, 2006
/s/ Chris E. Williford Chris E. Williford	Exec. Vice President and Treasurer (Principal Financial and Accounting Officer)	March 22, 2006
/s/ Craig S. Bartlett, Jr. Craig S. Bartlett, Jr.	Director	March 22, 2006
/s/ Franklin A. Burke Franklin A. Burke	Director	March 22, 2006
/s/ Harold D. Carter Harold D. Carter	Director	March 22, 2006
/s/ Ralph F. Cox Ralph F. Cox	Director	March 22, 2006
/s/ Barry J. Galt Barry J. Galt	Director	March 22, 2006
/s/ Dennis E. Logue Dennis E Logue	Director	March 22, 2006
/s/ Paul Powell Paul Powell	Director	March 22, 2006
/s/ Joseph A. Wagda Joseph A. Wagda	Director	March 22, 2006

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Abraxas Petroleum Corporation and Subsidiaries

All schedules are omitted because they are not required, are not applicable or the information required is included in the Consolidated Financial Statements or the notes thereto.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
Abraxas Petroleum Corporation:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control - Integrated Framework. Based on our assessment, we believe that, as of December 31, 2005, our internal control over financial reporting is effective based on those criteria.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, has been audited BDO Seidman, LLP, an independent registered public accounting firm which also audited our consolidated financial statements. BDO Seidman's attestation report on management's assessment of our internal control over financial reporting is included under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting."

By: /s/ Robert L.G. Watson   By: /s/ Chris E. Williford
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Robert L.G. Watson
President and Chief Executive Officer

Chris E. Williford
Executive Vice President and
Chief Financial Officer

San Antonio, Texas
March 8, 2006

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Abraxas Petroleum Corporation
San Antonio, Texas

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation and subsidiaries as of December 31, 2005 and 2004 and the related consolidated statements of operations, stockholders' deficit, cash flows and other comprehensive income (loss) for each of the three years in the period ended December 31, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). 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, 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Abraxas Petroleum Corporation at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation during 2005.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Abraxas Petroleum Corporation's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 8, 2006 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Dallas, Texas

March 8, 2006

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders
Abraxas Petroleum Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting and Scope of Management's Report, that Abraxas Petroleum Corporation maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Abraxas Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Abraxas Petroleum Corporation maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Abraxas Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2005 and 2004 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005 of Abraxas Petroleum Corporation and our report dated March 8, 2006 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Dallas, Texas
March 8, 2006

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31	
	2005	2004 (
	(Dollars in thousands)	
Current assets:		
Cash	$ 42	$
Accounts receivable:		
Joint owners	540	
Oil and gas production sales	7,957	
Other	100	
	8,597	
Other current assets	1,638	
	10,277	
Assets held for sale..................................	-	5
Total current assets...............................	10,277	5
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	333,373	29
Other property and equipment	3,289	

Total	336,662	30
Less accumulated depreciation, depletion, and amortization	231,414	22
Total property and equipment - net	105,248	7
Deferred financing fees net	6,037	
Deferred tax asset..	-	
Other assets	304	
Total assets	$ 121,866	$ 15

(1) Reflects retrospective adoption of SFAS 123R, see Note 2.

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' DEFICIT

	December 31	
	2005	2004 (
	(Dollars in thousands)	
Current liabilities:		
Accounts payable	$ 9,814	$
Joint interest oil and gas production payable	3,481	
Accrued interest	1,368	
Other accrued expenses	494	
	15,157	1
Liabilities related to assets held for sale...............	-	6
Total current liabilities..............................	15,157	7
Long-term debt	129,527	12
Future site restoration	883	
Stockholders' equity (deficit):		
Common stock, par value $.01 per share - authorized 200,000,000 shares; issued 42,063,167 and 36,597,045	421	
Additional paid-in capital	162,795	15
Accumulated deficit	(188,193)	(20

Treasury stock, at cost, 56,477 and 105,989 shares.........	(408)	
Accumulated other comprehensive income....................	1,684	
Total stockholders' deficit................................	(23,701)	(5
Total liabilities and stockholders' deficit...............	$ 121,866	$ 15

(1) Reflects retrospective adoption of SFAS 123R, see Note 2.

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December	
	2005	2004 (1)
	(In thousands except pe	
Revenues:		
Oil and gas production revenues	$ 47,314	$ 33,073
Rig revenues	1,295	771
Other	16	10
	48,625	33,854
Operating costs and expenses:		
Lease operating and production taxes	11,094	8,567
Depreciation, depletion, and amortization	8,914	7,213
Rig operations	756	671
General and administrative (including stock-based compensation of $247; $112; and $228)................	5,757	5,238
	26,521	21,689
Operating income	22,104	12,165
Other (income) expense:		
Interest income	(19)	(10
Amortization of deferred financing fees	1,589	1,848
Interest expense	13,989	17,867
Financing costs..	-	1,657
Gain on debt redemption..................................	-	(12,561
Other	274	387
	15,833	9,188
Income (loss) from continuing operations before cumulative effect of accounting change	6,271	2,977
Cumulative effect of accounting change.....................	-	-

Net income (loss) from continuing operations before income tax	6,271	2,977
Deferred income tax benefit	-	(6,060
Income (loss) from continuing operations	6,271	9,037
Net income from discontinued operations	12,846	3,323
Net income	$ 19,117	$ 12,360
Basic earnings (loss)per common share:		
Net earnings (loss) from continuing operations	$ 0.16	$ 0.25
Discontinued operations	0.33	0.09
Cumulative effect of accounting change	-	-
Net income per common share - basic	$ 0.49	$ 0.34
Diluted earnings (loss) per common share:		
Net earnings (loss) from continuing operations	$ 0.15	$ 0.23
Discontinued operations	0.31	0.09
Cumulative effect of accounting change	-	-
Net income per common share - diluted	$ 0.46	$ 0.32

(1)Reflects retrospective adoption of SFAS 123R, see Note 2.

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' DEFICIT
(In thousands except number of shares)

	Common Stock		Treasury Stock		Additional	
	Shares	Amount	Shares	Amount	Paid-In Capital	Accumulated Deficit
Balance December 31, 2002						
as originally reported...	30,145,280	$ 301	165,883	$ (964)	$136,830	$ (269,621)
Cumulative effect of change in accounting for stock-based compensation.	-	-	-	-	6,847	(6,847)
Balance at December 31, 2002 as adjusted for SFAS 123R.	30,145,280	$ 301	165,883	$ (964)	$143,677	$ (276,468)
Net income	-	-	-	-	-	56,798
Foreign currency						

translation adjustment	-	-	-	-	-	-
Stock-based compensation expense................	-	-	-	-	228	-
Stock options exercised .	129,352	1	-	-	84	-
Stock issued for acquisition of Wind River Resources........	106,977	1	-	-	91	-
Stock issued in connection with exchange offer.........	5,642,699	57	-	-	3,724	-
Balance at December 31, 2003	36,024,308	$ 360	165,883	$ (964)	$147,804	$ (219,670)
Net income..............	-	-	-	-	-	12,360
Foreign currency translation adjustment	-	-	-	-	-	-
Proceeds from receivable	-	-	-	-	-	-
Stock issued for compensation...........	58,808	1	(59,894)	415	(87)	-
Stock-based compensation expense................	-	-	-	-	112	-
Stock options and warrants exercised	513,929	5	-	-	3,132	-
Balance December 31, 2004	36,597,045	$ 366	105,989	$ (549)	$150,961	$ (207,310)
Net Income...............	-	-	-	-	-	19,117
Foreign currency translation adjustment	-	-	-	-	-	-
Increase in carrying value of investments........	-	-	-	-	-	-
Stock-based compensation.	-	-	-	-	247	-
Shares issued for compensation............	-	-	(49,512)	141	(39)	-
Stock options exercised..	461,408	5	-	-	423	-
Stock warrants exercised.	996,479	10	-	-	(10)	-
Stock issued in private placement.............	4,000,000	40	-		11,213	-
Other....................	8,235	-	-	-	-	-
Balance at December 31, 2005	42,063,167	$ 421	56,477	$ (408)	$162,795	$ (188,193)

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended De

	2005	2004
		(In thousa
Operating Activities		
Net income	$ 19,117	$ 12,360
Income from discontinued operations...............	12,846	3,323
Income (loss) from continuing operations...........	6,271	9,037
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion, and amortization	8,914	7,213
Non-cash interest and financing cost...........	-	5,967
Accretion of future site restoration...........	19	108
Deferred tax benefit..........................	-	(6,060)
Amortization of deferred financing fees........	1,589	1,848
Stock-based compensation	247	112
Changes in operating assets and liabilities:		
Accounts receivable	(2,312)	7,816
Other	3,127	(291)
Accounts payable	5,230	990
Accrued expenses	(1,986)	260
Net cash provided by continuing operations.........	21,099	27,000
Net cash provided by (used in) discontinued operations................................	(4,132)	3,265
Net cash provided by operations...................	16,967	30,265
Investing Activities		
Capital expenditures, including purchases and development of properties	(35,350)	(9,269)
Net cash used in continuing operations.............	(35,350)	(9,269)
Net cash provided by (used in) discontinued operations....................................	25,671	(12,069)
Net cash (used in) provided by investing activities.	(9,679)	(21,338)
Financing Activities		
Proceeds from issuance of common stock............	11,783	3,465
Proceeds from long-term borrowings	28,374	147,955
Payments on long-term borrowings	(25,272)	(212,146)
Deferred financing fees	(8)	(5,056)
Other...	-	98
Net cash provided by (used in) continuing operations..................................	14,877	(65,684)
Net cash provided by (used in) discontinued operations..................................	(23,407)	58,041
Net cash (used in) provided by financing activities..................................	(8,530)	(7,643)
Increase (decrease) in cash	(1,242)	1,284
Cash at beginning of year	1,284	-
Cash at end of year.............................	$ 42	$ 1,284

(1) Reflects retrospective adoption of SFAS 123R, see Note 2.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOW (CONTINUED)

	Years Ended Decemb	
	2005	2004
		(In thousands
Supplemental disclosures of cash flow information:		
Interest paid	$ 12,583	$ 7,6

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME

	Years End	
	2005	
		(In
Net income	$ 19,117	$
Other Comprehensive income:		
Foreign currency translation adjustment		
Reclassification of foreign currency translation adjustment relating to the sale of foreign subsidaries..	(2,190)	
Effect of change in exchange rate......................	(878)	
Change in carrying value of investment...................	1,684	
Other comprehensive income	(1,384)	
Comprehensive income	$ 17,733	$

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Significant Accounting Policies

Nature of Operations

Abraxas Petroleum Corporation (the "Company" or "Abraxas") is an independent energy company primarily engaged in the exploitation of 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 Wyoming. 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 subsidiary, Grey Wolf Exploration Inc. ("Grey Wolf"). On February 28, 2005 Grey Wolf closed an initial public offering, resulting in the substantial divestiture of our capital stock and operations in Grey Wolf. As a result of the disposal of Grey Wolf, the results of operations of Grey Wolf through February 28, 2005 are reflected in our financial statements as discontinued operations.

Use of Estimates

The preparation of consolidated 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 consolidated 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 and crude oil and natural gas price hedges. 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.

The Company maintains its cash and cash equivalents in excess of Federally insured limits in prominent financial institutions considered by the Company to be of high credit quality.

Cash and Equivalents

Cash and cash equivalents includes cash on hand, demand deposits and short-term investments with original maturities of three months or less.

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $11,000 and $10,000 at December 31, 2004 and 2005, respectively. The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

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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, as adjusted for asset retirement obligations, less related deferred taxes, are limited 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.

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 are primarily in the form of price floors, which limit the impact of price reductions with respect to the Company's sale of crude oil and natural gas. The Company does not enter into speculative hedges.

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. In 2003, the Company elected out of hedge accounting as prescribed by SFAS 133. Accordingly all derivatives will be recorded on the balance sheet at fair value with changes in fair value being recognized in earnings.

Foreign Currency Translation

The functional currency for Grey Wolf 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 the consolidated financial statement of stockholders' deficit. The amount reflected in the accompanying financial statements relates to discontinued operations. In 2005 the Company disposed of substantially all operations of Grey Wolf.

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 Company is subject to extensive Federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 is effective for us January 1, 2003. SFAS 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. 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 in the accompanying consolidated financial statements.

The following table summarizes the Company's asset retirement obligation transactions related to continuing operations during the following years:

	2005	2004
Beginning asset retirement obligation.........	$ 888	$ 776
New wells placed on production and other	115	132
Deletions related to property disposals.......	(139)	(128)
Accretion expense.............................	19	108
Ending asset retirement obligation............	$ 883	$ 888

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Revenue Recognition and Major Customers

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 at December 31, 2005 and 2004.

During 2003, 2004 and 2005 sales to two customers accounted for approximately 80%, 64% and 61% of crude oil and natural gas revenues.

Deferred Financing Fees

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

Assets and Liabilities Held for Sale

The Company holds assets and liabilities related to discontinued operations as held for sale, in accordance with Statement of Financial Standards No. 144 "Accounting for Impairment of Disposal of Long-Lived Assets" (SFAS 144). The Company records its assets at the lower of its carrying amount or fair market value less cost to sell and does not depreciate or amortize the assets while classified as held for sale.

Income Taxes

The Company records deferred 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. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts expected to be realized.

Other Comprehensive Income

FASB Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" (SFAS 130) requires disclosure of comprehensive income, which includes reported net income as adjusted for other comprehensive income. Other Comprehensive income is defined as the change in equity of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. The components of other comprehensive income for the Company are foreign currency translation adjustments and change in the market value of marketable securities.

New Accounting Pronouncements

In March 2005 the FASB issued Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations--an interpretation of FASB Statement No. 143". This Interpretation clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred--generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. Statement 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

This Interpretation is effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application for interim financial information is permitted but is not required. Early adoption of this Interpretation is encouraged. This statement did not effect the Company's financial statements for the period ended December 31, 2005.

In May 2005, the FASB issued "Summary of Statement No. 154 Accounting Changes and Error Corrections" - a replacement of APB Opinion No. 20 and FASB Statement No. 3. This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting for and reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed.

Opinion 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the

change. When it is impracticable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in an income statement. When it is impracticable to determine the cumulative effect of applying a change in accounting principle to all prior periods, this Statement requires that the new accounting principle be applied as if it were adopted prospectively from the earliest date practicable.

This Statement defines retrospective application as the application of a different accounting principle to prior accounting periods as if that principle had always been used or as the adjustment of previously issued financial statements to reflect a change in the reporting entity. This Statement also redefines restatement as the revising of previously issued financial statements to reflect the correction of an error.

This Statement requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in non-discretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change.

This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate effected by a change in accounting principle.

This Statement carries forward without change the guidance contained in Opinion 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. This Statement also carries forward the guidance in Opinion 20 requiring justification of a change in accounting principle on the basis of preferability.

This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. This statement did not effect the Company's financial statements for the period ended December 31, 2005.

2. Accounting Change

Stock-based Compensation

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. In January 2003, we amended the exercise price to $0.66 per share on certain options with an existing exercise price greater than $0.66 per share which resulted in variable accounting. Under the rules of variable accounting, we recognized the difference in the market price of our common stock as of the end of the period and the exercise price of $0.66. If the market price of our common stock increased from the previous period we recognized expense, conversely, if the price decreased we recognized a benefit.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". SFAS No. 123R is a revision of SFAS No. 123, "Accounting for Stock Based Compensation", and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. The Company has elected early adoption of SFAS 123R .

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Under the "modified retrospective" method, the requirements

are the same as under the "modified prospective" method, but also permit entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS 123. The Company has elected to use the "modified retrospective" method. This standard requires the cost of all share-based payments, including stock options, to be measured at fair value on the grant date and recognized in the statement of operations. In accordance with this standard, all periods prior to January 1, 2005 were restated to reflect the impact of the standard as if it had been adopted on January 1, 1995, the original effective date of SFAS No. 123, "Accounting for Stock-Based Compensation". Also in accordance with the standard, the amounts that are reported in the statement of operations for the restated periods are the pro forma amounts previously disclosed under SFAS No. 123.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to Employees. While SFAS 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or "lattice" model. Based upon research done by the Company on the alternative models available to value option grants, and in conjunction with the type and number of stock options expected to be issued in the future, the Company has determined that it will continue to use the Black-Scholes model for option valuation as of the current time. 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 2003, 2004 and 2005, risk-free interest rates of 1.5% in 2003 and 2004 and 4.14% in 2005.; dividend yields of -0-%; volatility factors of the expected market price of the Company's common stock of .35 in 2003 and 2004 and .89 in 2005 determined by daily historical prices, and a weighted-average expected life of the option of ten years in 2003 and 2004 and 8.3 years in 2005.

SFAS 123R includes several modifications to the way that income taxes are recorded in the financial statements. The expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in the Company's effective tax rates recorded throughout the year. SFAS 123R does not allow companies to "predict" when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise stock options.

As a result of the adoption of this standard, the Company has recognized a reduction of stock based compensation expense of approximately $878,000 and $1.2 million for the years ended December 31, 2003 and 2004. This resulted in an increase in net income from continuing operations, net income before tax, net income and cash flow from operations of $878,000 and $1.2 million for 2003 and 2004 and an increase of $0.02 and 0.03 earnings per share for the respective periods. The Company recognized $247,000; $112,000; and $228,000 in stock-based compensation expense for 2005, 2004 and 2003 respectively as a result of the adoption of this standard. This reduced net income from continuing operations, net income before tax and net income in 2005 by $247,000 and reduced earnings per share by $0.01 in 2005.

3. Discontinued Operations

As part of the restructuring operations in 2004 the Company approved a plan to dispose of its operations and interest in Grey Wolf. On February 28, 2005, Abraxas substantially divested its investment in Grey Wolf. Pursuant to an Underwriting Agreement, the underwriters purchased 17,800,000 common shares of Grey Wolf capital stock from Grey Wolf (the "Treasury Shares"), and 9,100,000 shares of Grey Wolf common stock owned by Abraxas (the "Secondary Shares") from Abraxas at a purchase price of CDN $2.80 per share.

Abraxas also granted to the underwriters an over-allotment option to purchase from Abraxas, at the underwriters' election, up to an additional 3,902,360 shares of Grey Wolf common stock held by Abraxas (the "Option Shares"). The over-allotment option may be exercised in whole or in part at any one time prior to thirty calendar days after the closing date for the IPO. Grey Wolf utilized the proceeds from the sale of the Treasury Shares to re-pay and terminate its $35 million term loan and re-pay $1 million in inter-company debt to Abraxas. Abraxas utilized the $1 million received from Grey Wolf and the proceeds received from the sale of the Secondary Shares to re-pay outstanding debt under its $25 million bridge loan. After consummation of the offering, Abraxas' remaining debt under the bridge loan was $5.4 million - see Note 3. On March 24, 2005, the Company was advised of the underwriter's intent to exercise 3.5 million of the over allotment shares. Closing for this exercise occurred March 31 and provided approximately $7.5 million that Abraxas utilized to payoff

the remaining balance of its Bridge Loan. The remaining proceeds of approximately $2 million were used to pay down the Company's revolving credit facility to, effectively, zero.

The operations of Grey Wolf, previously reported as a business segment, are reported as discontinued operations for all periods presented in the accompanying financial statements and the operating results are reflected separately from the results of continuing operations. Interest attributable to discontinued operations represents interest on debt attributable to the Canadian subsidiary. Summarized discontinued operations operating results and net gain (loss) for the years ended December 31, 2003, 2004 and 2005 were:

	Years ended December	
	2005	2004
	(in thousands)	
Total revenue......................................	$ 3,129	$ 15,082
Income from operations before income tax (1).........	18,906 (1)	3,323
Income tax expense (benefit)........................	6,060	-
Income from discontinued operations (1).............	$ 12,846	$ 3,323

(1) Includes gain on sale of foreign subsidiary of $17.3 million in 2005.
(2) In 2003, as part of a series of transactions related to a financial

restructuring including an exchange offer, redemption of certain notes payable and a credit agreement, the Company sold its wholly owned Canadian subsidiaries. The 2003 statement of operations includes a gain on the sale of the Canadian subsidiaries in January 2003 of $68.9 million.

Assets and liabilities of discontinued operations were as follows:

	December 31, 2004 (in thousands)
Assets:	
Cash	$ 693
Accounts receivable	2,556
Net property	45,426
Deferred financing fees	3,577
Other	348
	$ 52,600
Liabilities:	
Accounts payable and accrued expenses	$ 5,262
Long-term debt (1)	60,000
Other	1,685
	$ 66,947

(1) Includes Abraxas Bridge Loan of $25 million and $35 million related to Grey Wolf term loan.

4. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2005 and 2004, respectively:

	December 31 2005	December 31 2004
	(in thousands)	
Floating rate senior secured notes due 2009	$ 125,000	$ 125,000
Senior secured revolving credit facility	4,527	1,425
	129,527	126,425
Less current maturities	-	-
	$ 129,527	$ 126,425

Floating Rate Senior Secured Notes due 2009. In connection with our October 2004 refinancing, Abraxas issued $125 million in principal aggregate amount of Floating Rate Senior Secured Notes due 2009. The notes will mature on December 1, 2009 and began accruing interest from the date of issuance, October 28, 2004 at a per annum floating rate of six-month LIBOR plus 7.50%. The initial interest rate on the notes was 9.72% per annum. The interest will be reset semi-annually on each June 1 and December 1, commencing on June 1, 2005. The current interest rate, effective December 1, 2005, is 12.08% per annum. Interest is payable semi-annually in arrears on June 1 and December 1 of each year, commencing on June 1, 2005.

The notes rank equally among themselves and with all of our unsubordinated and unsecured indebtedness, including our credit facility, and senior in right of payment to our existing and future subordinated indebtedness.

Each of our subsidiaries, Eastside Coal Company, Inc., Sandia Oil & Gas Corporation, Sandia Operating Corp., Wamsutter Holdings, Inc. and Western Associated Energy Corporation (collectively, the "Subsidiary Guarantors"), has unconditionally guaranteed, jointly and severally, the payment of the principal, premium and interest on the notes on a senior secured basis. In addition, any other subsidiary or affiliate of ours, that in the future guarantees any other indebtedness with us, or our restricted subsidiaries, will also be required to guarantee the notes.

The notes and the Subsidiary Guarantors' guarantees thereof, together with our credit facility and the Subsidiary Guarantors' guarantees thereof, are secured by shared first priority perfected security interests, subject to certain permitted encumbrances, in all of our and each of our restricted subsidiaries' material property and assets, including substantially all of our and their natural gas and crude oil properties and all of the capital stock (or in the case of an unrestricted subsidiary that is a controlled foreign corporation, up to 65% of the outstanding capital stock) of any entity, owned by us and our restricted subsidiaries (collectively, the "Collateral").

The notes may be redeemed, at the election of the Company, as a whole or from time to time in part, at any time after April 28, 2007, upon not less than 30 nor more that 60 days' notice to each holder of notes to be redeemed, subject to the conditions and at the redemption prices (expressed as percentages of principal amount) set forth below, together with accrued and unpaid interest and Liquidating Damages, if any, to the applicable redemption date.

Year	Percentage
From April 29, 2007 to April 28, 2008	104.00%
From April 29, 2008 to April 28, 2009	102.00%
After April 28, 2009	100.00%

Prior to April 28, 2007, we may redeem up to 35% of the aggregate original principal amount of the notes using the net proceeds of one or more equity offerings, in each case at the redemption price equal to the product of (i) the principal amount of the notes being so redeemed and (ii) a redemption price factor of 1.00 plus the per annum interest rate on the notes (expressed as a decimal) on the applicable redemption date plus accrued and unpaid interest to the applicable redemption date, provided certain conditions are also met.

If we experience specific kinds of change of control events, each holder of notes may require us to repurchase all or any portion of such holder's notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of repurchase.

The indenture governing the notes contains covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;

- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- permit restrictions on the ability of our subsidiaries to distribute or lend money to us;
- cause a restricted subsidiary to issue or sell its capital stock; and
- consolidate, merge or transfer all or substantially all of the consolidated assets of our and our restricted subsidiaries.

The indenture also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, including our credit facility, bankruptcy, and material judgments and liabilities.

Senior Secured Revolving Credit Facility. On October 28, 2004, we entered into an agreement for a new revolving credit facility having a maximum commitment of $15 million, which includes a $2.5 million subfacility for letters of credit. Availability under the revolving credit facility is subject to a borrowing base consistent with normal and customary natural gas and crude oil lending transactions.

Outstanding amounts under the revolving credit facility bear interest at the prime rate announced by Wells Fargo Bank, National Association plus 1.00%. Subject to earlier termination rights and events of default, the stated maturity date under the revolving credit facility is October 28, 2008.

We are permitted to terminate the revolving credit facility, and under certain circumstances, may be required, from time to time, to permanently reduce the lenders' aggregate commitment under the revolving credit facility. Such termination and each such reduction is subject to a premium equal to the percentage listed below multiplied by the lenders' aggregate commitment under the revolving credit facility, or, in the case of partial reduction, the amount of such reduction.

Year	% Premium
1	1.5
2	1.0
3	0.5
4	0.0

Each of our current subsidiaries has guaranteed, and each of our future restricted subsidiaries will guarantee, our obligations under the revolving credit facility on a senior secured basis. In addition, any other subsidiary or affiliate of ours, that in the future guarantees any of our other indebtedness or of our restricted subsidiaries will be required to guarantee our obligations under the revolving credit facility. Obligations under the revolving credit facility are secured, together with the notes, by a shared first priority perfected security interest, subject to certain permitted encumbrances, in all of our and each of our restricted subsidiaries' material property and assets, including substantially all of our and their natural gas and crude oil properties and all of the capital stock (or in the case of an unrestricted subsidiary that is a controlled foreign corporation, up to 65% of the outstanding capital stock) in any entity, owned by us and our restricted subsidiaries.

Under the revolving credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. The revolving credit facility requires us to maintain a minimum net cash interest coverage and also requires us to enter into hedging agreements on not less than 25% or more than 75% of our projected natural gas and crude oil production for a rolling six month period.

In addition to the foregoing and other customary covenants, the revolving credit facility contains a number of covenants that, among other things, restrict Abraxas' ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;

- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- make any change in the principal nature of our business;
- prepay, redeem, purchase or otherwise acquire any of our or our restricted subsidiaries' indebtedness;
- permit a change of control;
- directly or indirectly make or acquire any investment;
- cause a restricted subsidiary to issue or sell our capital stock; and
- consolidate, merge or transfer all or substantially all of the consolidated assets of Abraxas and our restricted subsidiaries.

The revolving credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities, and is subject to an Intercreditor, Security and Collateral Agency Agreement, which specifies the rights of the parties thereto to the proceeds from the Collateral.

Intercreditor Agreement. The holders of the notes, together with the lenders under our credit facility, are subject to an Intercreditor, Security and Collateral Agency Agreement, which specifies the rights of the parties thereto to the proceeds from the Collateral. The Intercreditor Agreement, among other things, (i) creates security interests in the Collateral in favor of a collateral agent for the benefit of the holders of the notes and the credit facility lenders and (ii) governs the priority of payments among such parties upon notice of an event of default under the Indenture or the credit facility.

So long as no such event of default exists, the collateral agent will not collect payments under the credit facility documents or the indenture governing the notes and other note documents (collectively, the "Secured Documents"), and all payments will be made directly to the respective creditor under the applicable Secured Document. Upon notice of an event of default and for so long as an event of default exists, payments to each credit facility lender and holder of the notes from us and our current subsidiaries and proceeds from any disposition of any collateral, will, subject to limited exceptions, be collected by the collateral agent for deposit into a collateral account and then distributed as provided in the following paragraph.

Upon notice of any such event of default and so long as an event of default exists, funds in the collateral account will be distributed by the collateral agent generally in the following order of priority:

first, to reimburse the collateral agent for expenses incurred in protecting and realizing upon the value of the Collateral;

second, to reimburse the credit facility administrative agent and the trustee, on a pro rata basis, for expenses incurred in protecting and realizing upon the value of the Collateral while any of these parties was acting on behalf of the Control Party (as defined below);

third, to reimburse the credit facility administrative agent and the trustee, on a pro rata basis, for expenses incurred in protecting and realizing upon the value of the Collateral while any of these parties was not acting on behalf of the Control Party;

fourth, to pay all accrued and unpaid interest (and then any unpaid commitment fees) under the credit facility;

fifth, if the collateral coverage value of three times the outstanding obligations under the credit facility would be met after giving effect to any payment under this clause "fifth," to pay all accrued and unpaid interest on the notes;

sixth, to pay all outstanding principal of (and then any other unpaid amounts, including, without limitation, any fees, expenses, premiums and reimbursement obligations) the credit facility;

seventh, to pay all accrued and unpaid interest on the notes (if not paid under clause "fifth");

eighth, to pay all outstanding principal of (and then any other unpaid amounts, including, without limitation, any premium with respect to) the notes; and

ninth, to pay each credit facility lender, holder of the notes, and other secured party, on a pro rata basis, all other amounts outstanding under the credit facility and the notes.

To the extent there exists any excess monies or property in the collateral account after all of our and our subsidiaries' obligations under the credit facility, the indenture and the notes are paid in full, the collateral agent will be required to return such excess to us.

The collateral agent will act in accordance with the Intercreditor Agreement and as directed by the "Control Party" which for purposes of the Intercreditor is the holders of the notes and the credit facility lenders, acting as a single class, by vote of the holders of a majority of the aggregate principal amount of outstanding obligations under the notes and the credit facility.

The Intercreditor Agreement provides that the lien on the assets constituting part of the Collateral that is sold or otherwise disposed of in accordance with the terms of each Secured Document may be released if (i) no default or event of default exists under any of the Secured Documents, (ii) we have delivered an officers' certificate to each of the collateral agent, the trustee, the credit facility administrative agent certifying that the proposed sale or other disposition of assets is either permitted or required by, and is in accordance with the provisions of, the applicable Secured Documents and (iii) the collateral agent has acknowledged such certificate.

The Intercreditor Agreement provides for the termination of security interests on the date that all obligations under the Secured Documents are paid in full.

5. Property and Equipment

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

	Estimated Useful Life	December 31 2005	
	Years	(In thousands)	
Crude oil and natural gas properties	-	$ 333,373	$
Equipment and other	3-39	3,289	
		$ 336,662	$

6. Stock Option Plans and Warrants

Stock Options

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

The Company's 1994 Long-Term Incentive Plan has authorized the grant of options to management, employees and directors for up to approximately 6.1 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, 2005 approximately 2.6 million options remain available for grant.

The Company's 2005 Employee Long-Term Equity Incentive Plan has authorized the grant of 1.2 million options to management and employees. Options have a term not to exceed 10 years. Options issued under this plan vest according to a vesting schedule as determined by the compensation committee. Vesting may occur upon (1) the attainment of one or more performance goals or targets established by the committee (2) the optionee's continued employment or service for a specified period of time, (3) the occurrence of any event or the satisfaction of any other condition specified by the committee; or (4) a combination of any of the foregoing. This plan is subject to stockholder approval at the Company's 2006 annual stockholders meeting.

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

	2005		2004		
	Options (000s)	Weighted-Average Exercise Price	Options (000s)	Weighted-Average Exercise Price	Options (000s)
Outstanding-beginning of year	2,893	$ 0.93	3,364	$ 0.90	3,305
Granted	716	4.33	-	-	360
Exercised	(461)	0.93	(414)	0.69	(129
Forfeited/Expired	(132)	0.67	(57)	0.77	(172
Outstanding-end of year ...	3,016	$ 0.88	2,893	$ 0.93	3,364
Exercisable at end of year	2,225	$ 1.04	2,327	$ 0.97	2,331

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

	2005	2004
Weighted-average fair value of options granted during the year	$ 2,436,320	$ -
Intrinsic value of options exercised..............	$ 245,346	$ 153,155
Intrinsic value of options forfeited..............	$ 41,092	$ 20,053
Intrinsic value of non-vested options at beginning of year.......	$ 207,970	$ 669,521
Intrinsic value of non-vested options at end of year............	$ 2,427,269	$ 207,970
Intrinsic value of vested options at beginning of year...................	$ 1,481,543	$ 1,502,654
Intrinsic value of vested options at end of year..	$ 1,409,468	$ 1,481,543

The intrinsic fair value of options exercisable and options outstanding as of December 31, 2005 is $1.5 million and $3.9 million, respectively. As of December 31, 2005 the total compensation cost related to nonvested awards not yet recognized is approximately $2.3 million, which will be recognized in 2006 through 2009.

The following table represents the range of option prices and the weighted average remaining life of outstanding options as of December 31, 2005:

	Options outstanding			
Exercise price	Number outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable
$ 0.50 - 0.97	1,783,265	4.0	$ 0.70	1,648,140
$ 1.01 - 1.41	240,000	5.9	1.20	200,000
$ 2.06 - 2.75	346,857	3.1	2.24	346,857
$ 4.59 - 4.83	646,001	9.5	4.60	30,001

In January 2003, in connection with the financial restructuring, approximately 1.9 million options with a strike price greater that $0.66 were re-priced to $0.66.

Stock Awards

In addition to stock options granted under the plan 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 2003 or 2005. In 2004, 37,719 shares were awarded related to incentive bonus plans.

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. There were no direct awards of common stock in 2003, 2004 or 2005.

On June 1, 2005, the stockholders approved the 2005 Non-Employee Directors Long-Term Equity Incentive Plan (the "2005 Directors Plan"). The following is a summary of the 2005 Directors Plan.

Purpose. The purpose of the 2005 Directors Plan is to attract and retain members of the Board of Directors and to promote the growth and success of Abraxas by aligning the long-term interests of the Board of Directors with those of Abraxas' stockholders by providing an opportunity to acquire an interest in Abraxas and by providing both rewards for exceptional performance and long term incentives for future contributions to the success of Abraxas.

Administration and Eligibility. The 2005 Directors Plan will be administered by the Compensation Committee (the "Committee") of the Board of Directors and authorizes the Board to grant non-qualified stock options or issue restricted stock to those persons who are non-employee directors of Abraxas, including advisory directors of Abraxas, which currently amounts to a total of nine people.

Shares Reserved and Awards. The 2005 Directors Plan reserves 900,000 shares of Abraxas common stock, subject to adjustment following certain events, as discussed below. The 2005 Directors Plan provides that each year, at the first regular meeting of the Board of Directors immediately following Abraxas' annual stockholder's meeting, each non-employee director shall be granted or issued awards of 10,000 shares of Abraxas common stock, for participation in Board and Committee meetings during the previous calendar year. The maximum annual award for any one person is 10,000 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise share price shall be no less than 100% of the fair market value on the date of the award while the option terms and vesting schedules are at the discretion of the Committee.

Stock Warrants

In October 2004, the Company issued 1.1 million warrants in conjunction with the refinancing. Each is exercisable for one share of common stock at an exercise price of $0.01 per share. These warrants had a ten year term and were exercised in March 2005.

At December 31, 2005, the Company has approximately 4.0 million shares reserved for future issuance for conversion of its stock options, warrants, and incentive plans for the Company's directors, employees and consultants.

7. 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 31	
	2005	2004
	(In thousands)	
Deferred tax liabilities:		
Marketable securities	$ 509	$ -
U.S. full cost pool	11,621	7,310
Total deferred tax liabilities	12,130	7,310
Deferred tax assets:		
Capital loss carryforward	5,325	11,913
Depletion	3,542	3,232
Net operating losses ("NOL")	66,596	64,408

Investment in foreign subsidiaries	-	2,426
Canadian loss (Grey Wolf)	572	-
Other	3,023	4,387
Total deferred tax assets	79,058	86,366
Valuation allowance for deferred tax assets	(66,928)	(72,996)
Net deferred tax assets	12,130	13,370
Net deferred tax assets	$ -	$ (6,060)

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

	2005	2004	2003
		(in thousands)	
Current:			
Federal	$ -	$ -	$ -
Foreign	-	-	-
	$ -	$ -	$ -
Deferred:			
Federal	$ (6,060)	$ 6,060	$ -
Foreign	-	-	377
	(6,060)	6,060	377
Attributable to discontinued operations	(6,060)	-	(377)
Attributable to continuing operations	$ -	$ 6,060	$ -

At December 31, 2005 the Company had, subject to the limitation discussed below, $190.0 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2006 through 2025 if not utilized.

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 $73.0 million and $67.0 million for deferred tax assets at December 31, 2004 and 2005, respectively.

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

	December 31		
	2005	2004	
		(in thousands)	
Tax (expense) benefit at U.S. statutory rates (35%)	$ (6,691)	$ (1,875)	$
Decrease in deferred tax asset valuation allowance	6,068	8,123	
Higher effective rate of foreign operations	-	(140)	
Deferred tax expense - Disc. Ops.	(6,060)	-	
Other	623	(48)	
	$ (6,060)	$ 6,060	$
Attributable to discontinued operations	(6,060)	-	

Attributable to continuing operations..	$ -	$ 6,060	$

8. Commitments and Contingencies

Operating Leases

During the years ended December 31, 2003, 2004 and 2005 the Company incurred rent expense related to leasing office facilities of approximately $246,650, $256,355 and $248,684 respectively. Future minimum rental payments are as follows at December 31, 2005.

2006..	$ 254,435
2007..	254,538
2008..	250,148
2009..	20,773
Thereafter..	-
	$ 779,894

Litigation and Contingencies

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, 2005 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.

9. Earnings per Share

Basic earnings (loss) per share excludes any dilutive effects of options, warrants and convertible securities and is computed by dividing income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share are computed similar to basic, however diluted earnings per share reflects the assumed conversion of all potentially dilutive securities.

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

	2005	2004	
Numerator:			
Net income (loss) before effect of discontinued			
operations and accounting change	$ 6,271,000	$ 9,037,000	$
Discontinued operations.........................	12,846,000	3,323,000	
Cumulative effect of accounting change..........	-	-	
	19,117,000	12,360,000	
Denominator:			
Denominator for basic earnings per share -			
weighted-average shares	39,366,561	36,221,887	
Effect of dilutive securities:			

Stock options and warrants....................	1,796,942	2,672,778	
Dilutive potential common shares Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options and warrants................	41,163,503	38,894,665	
Basic earnings (loss) per share:			
Net income (loss) before effect of discontinued operations and accounting change.................	$ 0.16	$ 0.25	$
Discontinued operations	0.33	0.09	
Cumulative effect of accounting change..........	-	-	
Net income per common share......................	$ 0.49	$ 0.34	$
Diluted earnings (loss) per share:			
Net income (loss) before effect of discontinued operations and accounting change.................e	$ 0.15	$ 0.23	$
Discontinued operations..........................	0.31	0.09	
Cumulative effect of accounting change..........	-	-	
Net income per common share - diluted........	$ 0.46	$ 0.32	$

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For the year ended December 31, 2003, 711,000 shares were excluded from the calculation of diluted earnings per share since their inclusion would have been anti-dilutive.

10. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2004 and 2005 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter
		(In thousands, except per share data)	
Year Ended December 31, 2004			
Net revenue..........................	$ 7,960	$ 8,504	$ 8,237
Operating income - as previously reported	$ 576	$ 4,847	$ 1,837
SFAS 123R adjustment.................	2,026	(2,351)	1,345
Operating income (loss) - adjusted for 123R..........................	$ 2,602	$ 2,496	$ 3,182
Net income (loss) - as previously reported..........................	$ (5,557)	$ 372	$ (1,643)
SFAS 123R adjustment.................	2,026	(2,351)	1,345
Net income (loss)- adjusted for 123R..	$ (3,531)	$ (1,979)	$ (298)

Net income (loss) per common share - basic as previously reported........	$ (0.15)	$ 0.01	$ (0.05)
Net income (loss) per common share - basic - adjusted for 123R...........	$ (0.10)	$ (0.05)	$ (0.01)
Net income (loss) per common share - diluted - as previously reported....	$ (0.15)	$ 0.01	$ (0.05)
Net income (loss) per common share - diluted - adjusted for 123R.........	$ (0.09)	$ (0.05)	$ (0.01)
Year Ended December 31, 2005			
Net revenue	$ 7,822	$ 9,627	$ 14,164
Operating income- as previously reported...........................	$ 2,079	$ 4,350	$ 868
SFAS 123R adjustment.................	578	(342)	7,037
Operating income - adjusted for 123R..	$ 2,657	$ 4,008	$ 7,905
Net income (loss) - as previously reported...........................	$ 9,217	$ 278	$ (3,254)
SFAS 123R adjustment.................	578	(342)	7,037
Net income - adjusted for 123R........	9,795	(64)	3,783
Correct gain on sale of subsisiary....	2,190	-	-
Net income (loss) - restated.........	$ 11,985	$ (64)	$ 3,783
Net income (loss) per common share - basic - as previously reported......	$ 0.25	$ 0.01	$ (0.08)
Net income (loss) per common share - basic - as restated................	$ 0.33	$ 0.00	$ 0.09
Net income (loss) per common share - diluted - as previously reported....	$ 0.25	$ 0.01	$ (0.08)
Net income (loss) per common share - diluted - as restated..............	$ 0.33	$ 0.00	$ 0.09

(1) An error occurred in calculating the gain on the sale of Grey Wolf in February 2005. The error related to Grey Wolf's other comprehensive income relating to foreign currency translation at the time of the disposition. The correctio of the error resulted in an increase in income from discontinued operations and net income of $2.2 million.

11. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees of the Company. The Company matched employee contributions in 2004 and matched 50% of employee contributions in 2005. The Company did not contribute to the plan in 2003. 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 $13,000 in 2004 and $14,000 in 2005. The contribution limit for 2004 and 2005 was $16,000 and $18,000 for employees 50 years of age or older, respectively.

12. Hedging Program and Derivatives

On January 1, 2001, the Company adopted SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" SFAS 133 as amended by SFAS 137 "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB 133" and SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities. In 2003 the Company elected out of hedge accounting as prescribed by SFAS 133. Accordingly, instruments are recorded on the balance sheet at their fair value with adjustments to the carrying value of the instruments bring recognized in oil and gas income in the current period.

Under the terms of the Company's revolving credit facility, 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 December 31, 2005 the Company's hedging positions were as follows:

Time Period	Notional Quantities	Price
April 2006	10,000 MMbtu of production per day	Floor of $7.00
May 2006	10,000 MMbtu of production per day	Floor of $8.00
June 2006	10,000 MMbtu of production per day	Floor of $8.00
July 2006	10,000 MMbtu of production per day	Floor of $7.00
August 2006	10,000 MMbtu of production per day	Floor of $6.00
September 2006	10,000 Mmbtu of production per day	Floor of $5.00

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 effective in offsetting changes in cash flows of hedged items.

13. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying table presents information concerning the Company's crude oil and natural gas producing activities from continuing operations 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 from continuing operations are as follows:

	Years Ended December 31	
	2005	2004
	(In thousands)	
Proved crude oil and natural gas properties	$ 333,373	$ 298,382
Unproved properties	-	-
Total......................	333,373	298,382
Accumulated depreciation, depletion, and amortization, and impairment	(228,544)	(219,726)

Net capitalized costs ..	$ 104,829	$ 78,656

Cost incurred in oil and gas property acquisitions and development activities related to continuing operations are as follows:

	Years Ended December 31		
	2005	2004	2003
	(In Thousands)		
Property acquisition costs:			
Proved	$ -	$ -	$ -
Unproved	-	-	-
	$ -	$ -	$ -
Property development and exploration costs	$ 34,991	$ 9,088	$ 9,158

The results of operations for oil and gas producing activities from continuing operations for the three years ending December 31, 2005, 2004 and 2003, respectively are as follows:

	Years Ended December 31		
	2005	2004	2003
	(In thousands)		
Revenues	$ 47,314	$ 33,073	$ 29,710
Production costs	(11,094)	(8,567)	(8,342)
Depreciation, depletion, and amortization	(8,818)	(7,117)	(7,428)
General and administrative .	(1,378)	(1,281)	(998)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 26,024	$ 16,108	$ 12,942
Depletion rate per barrel of oil equivalent	$ 8.77	$ 7.39	$ 7.24

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, 2005, 2004, and 2003 related to continuing operations. 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.

	Liquid Hydrocarbons	N
	(Barrels)	
	(In thousan	
Proved developed and undeveloped reserves:		
Balance at December 31, 2002	3,236	
Revisions of previous estimates	268	
Extensions and discoveries	44	
Production	(229)	
Balance at December 31, 2003.....................	3,319	
Revisions of previous estimates	(59)	
Extensions and discoveries	70	

Production	(229)	
Balance at December 31, 2004.....................	3,101	
Revisions of previous estimates	9	
Extensions and discoveries	168	
Production	(194)	
Balance at December 31, 2005	3,084	

	Liquid Hydrocarbons	N
	(Barrels)	
Proved developed reserves:		
December 31, 2003................................	1,886	
December 31, 2004................................	1,878	
December 31, 2005................................	1,942	

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, 2005 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 relating to continuing operations for the three years ending December 31, 2005, 2004 and 2003.

	Years Ended December 31		
	2005	2004	2003
	(in Thousands)		
Future cash inflows ...	$ 937,638	$ 498,165	$ 512,797
Future production and development costs ...	(295,323)	(194,187)	(179,036)
Future income tax expense	-	-	-
Future net cash flows .	642,315	303,978	333,761
Discount	(330,407)	(154,943)	(172,177)
Standardized Measure of discounted future net cash relating to proved reserves	$ 311,908	$ 149,035	$ 161,584

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 related to continuing operations:

	Year Ended December 31		
	2005	2004	200

	(In thousands)		
Standardized Measure, beginning of year	$ 149,035	$ 161,584	$
Sales and transfers of oil and gas produced, net of production costs	(36,220)	(24,506)	
Net changes in prices and development and production costs from prior year	142,116	(2,814)	
Extensions, discoveries, and improved recovery, less related costs	51,438	810	
Purchase of minerals in place.............	-	-	
Revision of previous quantity estimates ...	51	(1,818)	
Other	(9,415)	(380)	
Accretion of discount	14,903	16,159	
Standardized Measure, end of year	$ 311,908	$ 149,035	$