ABRAXAS

2008 Annual Report

LETTER TO OUR SHAREHOLDERS:

What an amazing year! Never in my almost 40 years in the oil industry have I seen such a dramatic reversal of fortune in such a short period of time. Unfortunately, this statement would also reflect the overall economy as well.

After a successful closing of a large acquisition in January, which incidentally has performed very well, we entered a period of unprecedented escalation of service costs and commodity prices which led to chronic shortages and delays in oilfield service equipment. Even though our cash flows were growing significantly, we could not get drilling rigs and other service equipment on a timely basis. This turned out to be a blessing in disguise though at the time it was very frustrating. Our drilling program was delayed to the point where we did not get over committed during the boom and were able to throttle back expenditures when the bust became apparent.

Even though we did not drill as many wells as originally planned, we did drill two significant wells toward the end of the year that will have a meaningful impact on us in the years to come. The Nordheim #2H (DeWitt County, Texas) was a successful horizontal well drilled to a total measured depth of 17,000 feet, including a 3,000 foot lateral in the Edwards formation. In preparation for a completion involving a seven stage frac, the toe of the lateral was opened up and unexpectedly flowed naturally at rates as high as 6 MMcf of gas per day. We decided to produce the well as-is and postpone the opening of the remaining six sections of the lateral with a multi-stage frac until a later date when gas prices may be higher or service costs lower. At the time of this letter, the well was still producing in excess of 2 MMcf of gas per day. We own a 75% working interest in this well which has four potential offset locations.

In our Brooks Draw area of east central Wyoming, the Lakeside #1H was a successful horizontal well drilled to a total measured depth of 12,500 feet, including a 3,900 foot lateral in the Turner formation. After the seven stage frac, the well tested at rates above 700 barrels of oil per day, and in February of 2009 was placed on production at a restricted rate of 200 - 300 barrels of oil per day where it continues to produce today. To our knowledge, this was the first well in the area to use modern horizontal completion technology perfected in the Bakken formation of the northern Rockies together with information gained from 3D seismic to help orient the lateral. We own a 100% working interest in a large acreage position in this area, of which approximately 14,000 acres is held by production and not subject to lease expiration. We have identified 15 additional locations on our 3D with similar natural fractures as the Lakeside #1H. Depending on commodity prices and services costs, plans are being made for additional drilling as early as this summer.

Although the results from these two wells were very satisfying, due to their timing, they did not contribute to 2008 production, but they do set up a nice year-over-year increase for 2009.

Abraxas Energy Partners, L.P. (the “Partnership”), which we own 47% of, had a busy and successful year. In addition to incorporating approximately 1,500 new properties from the acquisition that closed in January of 2008, the Partnership participated in the drilling of 40 new wells, all of which were successful. The most significant of which was the Henson #3H (Lavaca County, Texas). This horizontal well was drilled to the Edwards formation, completed with a multi-stage frac and flowed at rates as high as 10 MMcf of gas per day. The Partnership owns a 75% interest in this well which continues to produce at satisfactory rates a year after drilling.

Even though we have many years of development drilling in inventory which we expect will generate comparable results as obtained in 2008, times have changed. We are seeing friends struggle with financial distress, some of whom may not survive this downturn. With a clean balance sheet, Abraxas will survive and we will be around to take advantage of opportunities that may turn out to be the best of my career. Our plans are to emerge from the downturn a larger, stronger company, with a clean balance sheet and even more opportunities for the future than we have today.

Our team has grown with people fully capable of surviving the downturn, with the knowledge and desire to make something even better for all concerned. I thank you, our shareholders, for your patience, not only for Abraxas, but our nation and economy as a whole. They all will see a brighter day.

Yours very truly,

Robert L.G. Watson
President and Chief Executive Officer

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2008

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

Commission File Number 001-16071

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)

18803 Meisner Drive
San Antonio, TX 78258
(Address of principal executive offices)
(210) 490-4788
Registrant's telephone number, including area code

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class:	**Name of each exchange on which registered:**
Common Stock, par value $.01 per share	NASDAQ Stock Market

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 ☒

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 ☐

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 ☒ 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. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐	Smaller reporting company ☐

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

As of June 30, 2008, the aggregate market value of the common stock held by non-affiliates of the registrant was $243,774,232 based on the closing sale price as reported on the American Stock Exchange.

As of February 20, 2009, there were 49,621,711 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2009 Annual Meeting of shareholders to be held on May 21, 2009.	Part III

ABRAXAS PETROLEUM CORPORATION
FORM 10-K
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Forward-Looking Information

We make forward-looking statements throughout this document. Whenever you read a statement that is not simply a statement of historical fact (such as 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 heading "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 success in development, exploitation and exploration activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- prices for oil and gas;
- our ability to raise equity capital or incur additional indebtedness;
- economic and business conditions;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price 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 document.

Part I

Item 1. Business

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

Information contained in this report represents the operations of Abraxas Petroleum Corporation and Abraxas Energy Partners, L.P., which we refer to as the Partnership or Abraxas Energy Partners, which are consolidated for financial reporting purposes. The interest of the 52.7% owners of the Partnership is presented as minority interest. Abraxas beneficially owns the remaining 47.3% of the partnership interests. Abraxas has determined that based on its control of the general partner of the Partnership, this 47.3% owned entity should be consolidated for financial reporting purposes. The terms "Abraxas" or "Abraxas Petroleum" refer only to Abraxas Petroleum Corporation and the terms "we," "us," "our," or the "Company," refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires.

General

We are an independent energy company primarily engaged in the development and production of oil and gas. Historically, we have grown through the acquisition and subsequent development and exploration 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 number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

At December 31, 2008, our properties were located in the Rocky Mountain, Mid-Continent, Permian Basin and Gulf Coast regions of the United States.

Our Rocky Mountain properties consist of the following:

- Northern Rockies—Our properties in the Northern Rockies are located in the Williston Basin of North Dakota, South Dakota and Montana and consist of wells that produce oil from Paleozoic-aged carbonate reservoirs from the Madison formation at 8,000 feet down to the Red River formation at 12,000 feet, including the Bakken at 9,000 feet.

- Southern Rockies—Our properties in the Southern Rockies are located in the Green River, Powder River and Uinta Basins of Wyoming, Colorado and Utah and consist of wells that produce oil from Cretaceous-aged fractured shales in the Mowry and Niobrara formation and oil and gas from Cretaceous-aged sandstones in the Turner, Muddy and Frontier formations. Well depths range from 7,000 feet down to 10,000 feet.

  We have 894 gross (110 net) producing wells in the Rocky Mountain region.

Our Mid-Continent properties consist of the following:

- Arkoma Basin—Our properties in the Arkoma Basin are located in Oklahoma and Arkansas and consist of wells that mainly produce gas from Hartshorne coals at 3,000 feet.

- Anadarko Basin—Our properties in the Anadarko Basin are located in Oklahoma and the Texas Panhandle and consist of wells that mainly produce gas from Pennsylvanian-aged sandstones (Atoka/Morrow) from depths of up to 18,000 feet.

- ARK-LA-TEX—Our properties in the ARK-LA-TEX region principally produce from the East Texas/North Louisiana Basins and include wells that produce oil and gas from various formations.

  We have 602 gross (103 net) producing wells in the Mid-Continent region.

Our Permian Basin properties consist of the following:

- ROC Complex—Our properties in the ROC Complex are located in Pecos, Reeves and Ward Counties and consist of wells that produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet.

- Oates SW—Our properties in the Oates SW area are located in Pecos County and consist of wells that produce gas from the Devonian formation at a depth of approximately 13,500 feet.

- Eastern Shelf – Our properties in the Eastern Shelf are predominately located in Coke, Scurry and Mitchell Counties and consist of wells that produce oil and gas from the Strawn Reef formation at 5,000 to 6,000 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet.

  We have 236 gross (160 net) producing wells in the Permian Basin region.

Our Gulf Coast properties consist of the following:

- Edwards— Our properties in the Edwards trend are located in DeWitt and Lavaca Counties and consist of wells that produce gas from the Edwards formation at a depth of 13,500 feet.

- Portilla—The Portilla field – located in San Patricio County, was discovered in 1950 by The Superior Oil Company, predecessor to Mobil Oil Corporation, and consists of wells that produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.

- Wilcox – Our properties in the Wilcox are located in Goliad, Bee and Karnes Counties and consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from 8,000 to 11,000 feet.

We have 79 gross (55 net) producing wells in the Gulf Coast region.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas 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 oil-producing and gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices of oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenue, profitability and cash flow from operations. You should read the discussion under "Risk Factors – Risks Relating to Our Industry — Market conditions for oil and gas, and particularly volatility of prices for oil and gas, 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 oil and gas prices on us. To help mitigate the impact of commodity price volatility, we hedge a portion of our production through the use of fixed price swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Derivative Activities" and Note 14 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2008, two purchasers accounted for approximately 29% of our oil and gas sales. We believe that there are numerous other customers available to purchase our oil and gas and that the loss of one or more of these purchasers would not materially affect our ability to sell oil and gas.

Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our operations are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and 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 oil, gas and natural gas liquids were subject to significant federal regulation. At the present time, however, all sales of our oil and gas 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.

Gas Regulation

Historically, the gas industry as a whole has been more heavily regulated than the oil or other liquid hydrocarbons markets. Most regulations focus 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 storage services, firm and interruptible transportation services, and standby sales and gas balancing services), and to adopt a ratemaking methodology to determine appropriate rates for those services. To the extent the pipeline company or its sales affiliate markets 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 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 gas. Our physical sales of 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 gas in the marketplace. FERC continues to review and modify its regulations regarding the transportation of gas. The 2005 Energy Policy Act recently authorized FERC to allow 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 gas storage service.

In recent years FERC also has pursued a number of important policy initiatives which could significantly affect the marketing of gas in the United States. Most of these initiatives are intended to enhance competition in 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 is pursuing an inquiry into whether it should revise its test for determining whether and under what circumstances FERC may reassert jurisdiction over gas gathering companies that have been "spun-down" from an affiliated interstate 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 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 gas through gathering facilities owned by others. Although FERC decisions create the potential for increasing the cost of shipping our 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 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 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 oil and gas 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 oil and gas properties have statutory provisions regulating the exploration for and production of oil and gas. 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 oil and gas 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 oil and gas wells generally prohibit the venting or flaring of 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 oil and 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, 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 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 post production costs that are deductible 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, and or long-term storage fees. Between 2003 and 2005, the MMS promulgated new rules and procedures for determining the value of oil produced from federal lands for purposes of calculating royalties owed to the government. As a general matter the oil and gas industry as a whole has resisted these rules under an assumption that royalty burdens will substantially increase. At this time, we are unable to predict the ultimate cost and effects of these new rules on our operations.

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 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 oil and gas 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.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as CERCLA, and comparable state statutes impose strict, joint, and several liability, without regard to fault or legality of conduct, 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, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon 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 the ordinary operations of our properties, certain wastes may be generated 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 oil cleanups.

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 oil and gas. Although Abraxas Petroleum has 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 oil, such as us, to prepare and implement spill prevention, control and countermeasure plans and spill response plans relating to possible discharge of oil into surface waters. The federal Oil Pollution Act ("OPA") contains numerous requirements relating to prevention of, reporting of, and response to 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 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 oil and 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, oil and 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 oil and 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 oil and 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 oil and gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and 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 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 oil and 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.

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of our properties 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.

Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Oil and gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change, or the Protocol, became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as "greenhouse gases," that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol; however, Congress has recently considered proposed legislation directed at reducing "greenhouse gas emissions," and certain states have adopted legislation, regulations and/or initiatives addressing greenhouse gas emissions from various sources, primarily power plants. Additionally, on April 2, 2007, the U.S. Supreme Court ruled in *Massachusetts v. EPA* that the EPA has authority under the CAA to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks). The Court also held that greenhouse gases fall within the CAA's definition of "air pollutant," which could result in future regulation of greenhouse gas emissions from stationary sources, including those used in oil and gas exploration and production operations. The oil and gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our properties are not adversely impacted by the current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

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 oil and 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 various states in which we operate.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. If we were to conduct any exploration and production activities on federal lands in the future, those activities would need to obtain governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and gas projects.

Endangered Species Act. The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our facilities may be located in areas that may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the discovery of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Abandonment Costs. All of our oil and 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 oil and gas industry, we make only a cursory review of title to undeveloped oil and gas leases at the time we acquire them. However, before drilling commences, we require a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/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 oil and gas properties, some of which are subject to immaterial encumbrances, easements and restrictions. The oil and gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.

Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas 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 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 February 20, 2009 we had 65 full-time employees. We retain independent geological, land and engineering consultants from time to time on a limited basis and expect to continue to do so in the future.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. You may read and copy any document we file with the SEC at the SEC's public reference room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet web site that contains annual, quarterly and current reports, proxy statements and other information that issuers (including Abraxas) file electronically with the SEC. The SEC's web site is www.sec.gov.

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. Information on our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

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

We must 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 debt and equity securities and we expect to continue to do so in the future. Abraxas also anticipates receiving distributions of available cash from the Partnership. We cannot assure you that we will have sufficient capital resources in the future to finance all of our capital expenditures.

Volatility in oil and gas prices, the timing of both Abraxas' and the Partnership's drilling programs and drilling results will affect both Abraxas' and the Partnership's cash flow from operations as well as distributions of available cash by the Partnership to Abraxas. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet both Abraxas' and the Partnership's 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 planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

The borrowing bases under Abraxas' and the Partnership's credit facilities are determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the respective borrowing bases, which would reduce the amount of financial resources available under these facilities 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 oil and gas 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 bases decrease for any reason, both Abraxas' ability to undertake exploration and development activities, and the Partnerships' ability to undertake development activities could be adversely affected. The Partnership's ability to undertake exploration and development activities will also be effected by the limitation set forth in the Partnership's Credit Facility limiting capital expenditures to $12.5 million while the Partnership's Subordinated Credit Agreement remains outstanding. See "Management's Discussion and Analysis of Financial Condition and Results of Operations –Liquidity and Capital Resources – Long-Term Indebtedness." As a result, our ability to replace production may be limited. In addition, if the borrowing bases under Abraxas' and the Partnership's respective credit facilities are reduced, both Abraxas and the Partnership would be required to reduce their borrowings under their respective credit facilities so that such borrowings do not exceed such borrowing bases. This could further reduce the cash available to us for capital spending and, if either Abraxas or the Partnership did not have sufficient capital to reduce its respective borrowing level, Abraxas and/or the Partnership may be in default under their respective credit facilities.

Abraxas has sold producing properties to provide it with liquidity and capital resources in the past and both Abraxas and the Partnership may do so in the future. After any such sale, we would expect to utilize the proceeds to drill new wells on our remaining properties. If we cannot replace the production lost from properties sold with production from the remaining properties, both Abraxas' and the Partnership's cash flow from operations, including distributions of available cash from the Partnership, will likely decrease, which in turn, would decrease the amount of cash available for 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 oil and gas 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 oil and gas properties and our proved reserves will decline as our reserves are produced. Unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, we cannot assure you that our exploration and development activities will result in increases in our proved reserves. Approximately 92% of the Partnership's and 85% of Abraxas', or 92% of the estimated ultimate recovery of our consolidated proved developed producing reserves as of December 31, 2008, had been produced. Based on the reserve information set forth in our reserve report of December 31, 2008, Abraxas' average annual estimated decline rate for its net proved developed producing reserves is 18% during the first five years, 13% in the next five years, and approximately 7% thereafter. Based on the reserve information set forth in our reserve report of December 31, 2008, the Partnership's average annual estimated decline rate for its net proved developed producing reserves is 10% during the first five years, 8% in the next five years and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While Abraxas has had some success in finding, acquiring and developing additional reserves, Abraxas has not always been able to fully replace the production volumes lost from natural field declines and prior property sales. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. As our proved reserves and consequently our production decline, our cash flow from operations, the amount of cash distributions Abraxas receives from the Partnership and the amount that we are able to borrow under our credit facilities will also decline. In addition, approximately 65% of Abraxas' and 39% of the Partnership's total estimated proved reserves at December 31, 2008 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. Even if we are successful in our development efforts, it could take several years for a significant portion of these undeveloped reserves to generate positive cash flow.

We may not find any commercially productive oil and gas 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 oil and gas may be unprofitable. Dry holes and wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. The inherent risk of not finding commercially productive reservoirs will be compounded by the fact that 65% of Abraxas and 39% of the Partnership's, or 46% of our consolidated total estimated proved reserves at December 31, 2008, 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 oil and gas we produce decreases, our cash flow from operations and the amount of any distributions that Abraxas may receive from the Partnership will decrease.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- shortages or delays in the availability of drilling rigs, equipment and crews;
- adverse weather conditions;
- compliance with environmental and governmental rules and regulations;
- title problems;
- unusual or unexpected geological formations;
- pipeline ruptures;
- fires, blowouts and explosions; and
- uncontrollable flows of oil or gas or well fluids.

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 interests.

Abraxas' credit facility and the Partnership's credit facility contain a number of significant covenants that, among other things, limit both Abraxas' and the Partnership's 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;
- permit a change of control; or

- consolidate, merge or transfer all or substantially all of the consolidated assets of Abraxas and our restricted subsidiaries.

In addition, both Abraxas' credit facility and the Partnership's credit facility require each of them to maintain compliance with specified financial ratios and satisfy certain financial condition tests and the Partnership's Credit Facility limits the Partnership's capital expenditures to $12.5 million while the Partnership's Subordinated Credit Agreement remains outstanding. Both Abraxas' and the Partnership's ability to comply with these ratios and financial condition tests may be adversely affected by events beyond our control, and we cannot assure you that either Abraxas or the Partnership will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit both Abraxas' and the Partnership's 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 either Abraxas' or the Partnership's inability to comply with the required financial ratios or financial condition tests could result in a default under Abraxas' credit facility and/or the Partnership's credit facility. A default, if not cured or waived, could result in all of our indebtedness 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 or favorable to us.

The marketability of our production depends largely upon the availability, proximity and capacity of 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 oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on us could be substantial and adversely affect our ability to produce and market oil and gas.

An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations.

Our oil and gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for all of our oil and gas are lower than the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Additionally, insufficient pipeline capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas. For example, production increases from competing Canadian and Rocky Mountain producers, combined with limited refining and pipeline capacity in the Rocky Mountain area, have gradually widened differentials in this area.

During 2008, differentials averaged $7.07 per Bbl of oil and $1.30 per Mcf of gas. Approximately 39% of our production during 2008 was from our Rocky Mountain and Mid-Continent properties. Historically, these regions have experienced wider differentials than our Permian Basin and Gulf Coast properties. As the percentage of our production from the Rocky Mountain and Mid-Continent regions increases, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

The Partnership's derivative contract activities could result in financial losses or could reduce our cash flow.

To achieve more predictable cash flow and reduce our exposure to adverse fluctuations in the prices of oil and gas and to comply with the requirements under the Partnership's credit facility, we have and expect to continue to enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. The Partnership has entered into NYMEX-based fixed price commodity swap arrangements on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011. The extent of our commodity price exposure is related largely to the effectiveness and scope of our commodity price derivative contract activities. For example, the prices utilized in our derivative instruments are NYMEX-based, which may differ significantly from the actual prices we receive for oil and gas which are based on the local markets where oil and gas are produced. The prices that we receive for our oil and gas production are lower than the relevant benchmark prices that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. As a result, our cash flow could be affected if the basis differentials widen more than we anticipate. For more information see ''—An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations''. We currently do not have any basis differential hedging arrangements in place. Our cash flow could also be affected based upon the levels of our production. If production is higher than we estimate, we will have greater commodity price exposure than we intended. If production is lower than the nominal amount that is subject to our hedging arrangements, we may be forced to satisfy all or a portion of our hedging arrangements without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows.

If the prices at which the Partnership has hedged its oil and gas production are less than current market prices, its ability to maintain or increase cash distributions could be adversely affected.

The Partnership has entered into NYMEX-based fixed price commodity swap arrangements on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011. The volume weighted average prices at which the Partnership has hedged this production are $84.23 per barrel of oil and $8.27 per MMbtu of gas. The hedged prices of oil and gas were greater than NYMEX future prices on December 31, 2008 of $44.60 per barrel of oil and $5.62 per Mcf of gas. When the Partnership's derivative contract prices are at higher than market prices, the Partnership will incur realized and unrealized gains on its derivative contracts and when contract prices are lower than market prices, the Partnership will incur realized and unrealized losses. For the year ended December 31, 2008 the Partnership recognized a realized loss on oil and gas derivative contracts of $9.3 million and an unrealized gain of $40.5 million. The realized loss resulted in a decrease in cash flow from operations of the Partnership as well as negatively impacting cash available for distribution by the Partnership. The Partnership expects to continue to enter into similar hedging arrangements in the future to reduce its cash flow volatility.

The following table sets forth the Partnership's oil and gas derivative contract position at December 31, 2008:

Period Covered	Product	Volume (Production per day)	Weighted Average Fixed Price
Year 2009	Gas	10,595 Mmbtu	$ 8.45
Year 2009	Oil	1,000 Bbl	$ 83.80
Year 2010	Gas	9,130 Mmbtu	$ 8.22
Year 2010	Oil	895 Bbl	$ 83.26
Year 2011	Gas	8,010 Mmbtu	$ 8.10
Year 2011	Oil	810 Bbl	$ 86.45

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

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

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

We use the full cost method to account for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and earnings. The risk that we will be required to write-down the carrying value of oil and gas properties increases when oil and gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

At December 31, 2008, our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million resulting in a write-down of $116.4 million. We cannot assure you that we will not experience additional ceiling limitation writedowns in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2008, we had, subject to the limitation discussed below, $194.4 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2028 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 $66.9 million for deferred tax assets at December 31, 2006, $47.2 million at December 31, 2007 and $60.8 million at December 31, 2008.

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 Abraxas' Ownership of General Partner Units and Common Units of the Partnership

The Partnership's inability to refinance its obligations under the Subordinated Credit Agreement would have a material adverse impact on the liquidity, financial position and capital resources of Abraxas and the Partnership.

The Partnership's subordinated credit agreement matures on July 1, 2009. The Partnership intends to refinance this obligation prior to its scheduled maturity; however there can be no assurance that the Partnership will be successful in this effort. In addition, under the Partnership's subordinated credit agreement, an event of default would occur if the Partnership fails to receive $20.0 million of proceeds from an equity issuance on or before April 30, 2009. Abraxas Energy is currently in discussions with Société Générale to amend the existing Senior Secured Credit Facility and/or the Subordinated Credit Agreement in the event the IPO is not completed by April 30, 2009. The Partnership has also entered into discussions with other lending institutions to re-finance the $40 million currently outstanding on the Subordinated Credit

Agreement. While the Company believes that there are options to this short term maturity requirement, there are no guarantees that any of these options will be successfully implemented. If additional funds are obtained by issuing equity securities, the Partnership's existing unitholders, including Abraxas, would be diluted and the distributions Abraxas receives from the Partnership could decrease. To the extent that the Partnership is unable to refinance the indebtedness under the subordinated credit agreement, consummate an issuance of additional equity securities or obtain additional financing, the Partnership may be required to sell assets and reduce capital expenditures, including distributions to Abraxas in order to avoid an event of default. We cannot assure you that the Partnership will be able to refinance the indebtedness under the Subordinated Credit Agreement, sell assets, or obtain additional financing on terms acceptable to it, if at all. If an event of default were to occur under the Subordinated Credit Agreement, an event of default would also occur under the Partnership's Credit Facility. Upon an event of default, the Partnership's lenders could foreclose on the Partnership's assets and exercise other customary remedies, all of which would leave a material adverse effect on the Partnership and Abraxas. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Long-Term Indebtedness Critical Accounting Policies – Amended and Restated Partnership Credit Facility."

The Partnership may not have sufficient cash flow from operations to pay the quarterly distributions on the general partner units and common units following establishment of cash reserves and payment of fees and expenses.

Under the terms of the Partnership's partnership agreement, the amount of cash otherwise available for distribution will be reduced by the Partnership's operating expenses and the amount of any cash reserve amounts that its general partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to its unitholders, including Abraxas. The Partnership has informed Abraxas that the Partnership intends to reserve a substantial portion of its cash generated from operations to develop its oil and gas properties and to acquire additional oil and gas properties in order to maintain and grow the Partnership's level of oil and gas reserves.

The amount of cash the Partnership actually generates will depend upon numerous factors related to its business that may be beyond its control, including among other things:

- the amount of oil and gas it produces;
- price of oil and gas;
- continued drilling and development of oil and gas wells;
- the level of the Partnership's operating costs, including reimbursement of expenses to its general partner;
- prevailing economic conditions; and
- government regulation and taxation.

In addition, the actual amount of cash that the Partnership will have available for distribution will depend on other factors, including:

- the level of its capital expenditures;
- its ability to make borrowings under its credit facility to pay distributions;
- sources of cash used to fund acquisitions;
- debt service requirements and restrictions on distributions contained in its credit facility or future debt agreements;
- fluctuations in its working capital needs;
- general and administrative expenses;
- cash settlement of hedging positions;
- timing and collectability of receivables; and
- the amount of cash reserves, which the Partnership expects to be substantial, established by its general partner for the proper conduct of its business.

The Partnership is unlikely to be able to sustain its expected level of distributions without making accretive acquisitions or capital expenditures that maintain or grow its asset base. If the Partnership does not set aside sufficient cash reserves or make sufficient cash expenditures to maintain its asset base, it will be unable to pay distributions at the expected level from cash generated from operations and would likely reduce distributions.

The Partnership is unlikely to be able to sustain its expected level of distributions without making accretive acquisitions or capital expenditures that maintain or grow its asset base. The Partnership will need to make capital expenditures to maintain and grow its asset base, which will reduce cash available for distributions. Because the timing and amount of these capital expenditures fluctuate each quarter, the Partnership expects to reserve substantial amounts of cash each quarter to finance these expenditures over time. The Partnership may use the reserved cash to reduce indebtedness until it makes the capital expenditures. Over a longer period of time, if the Partnership does not set aside sufficient cash reserves or make sufficient expenditures to maintain its asset base, it may be unable to pay distributions at the expected level from cash generated from operations and would therefore expect to reduce cash distributions. Under the terms of the Partnership Credit Agreement, the Partnership capital expenditures are limited to $12.5 million until the Subordinated Credit Agreement has been terminated. If the Partnership does not make sufficient growth capital expenditures, it may be unable to sustain its business operations and therefore will be unable to maintain its proposed or current level of distributions and its business, financial condition and results of operations would be adversely affected.

To fund its capital expenditures, the Partnership will be required to use cash generated from operations, additional borrowings or the issuance of additional partnership interests, or some combination thereof.

Use of cash generated from operations by the Partnership will reduce cash available for distribution to Abraxas as a unitholder. The Partnership's ability to borrow from its credit facility or to obtain additional bank financing or to access the capital markets for future equity or debt offerings may be limited by its financial condition at the time of any such borrowing, financing or offering and the covenants in its then-existing debt agreements, as well as by adverse market conditions resulting from, among other things, general economic conditions, operations and contingencies and uncertainties that are beyond the Partnership's control. The Partnership's failure to obtain the funds for necessary future capital expenditures could have a material adverse effect on its business, results of operations, financial condition and ability to pay distributions. Even if the Partnership is successful in obtaining the necessary funds, the terms of such financings could limit its ability to pay distributions to unitholders, including Abraxas. In addition, incurring additional debt may significantly increase the Partnership's interest expense and financial leverage, and issuing additional partnership interests may result in significant unitholder dilution thereby increasing the aggregate amount of cash required to maintain the then-current distribution rate, which could have a material adverse effect on the Partnership's ability to pay distributions at the then-current distribution rate.

The Partnership intends to make acquisitions of oil and gas properties to grow its asset base. Properties that the Partnership acquires may not produce as projected and it may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could adversely affect its cash available for distribution.

Part of the Partnership's business strategy is to make accretive acquisitions of oil and gas properties. Any future acquisition will require an assessment of recoverable reserves, title, future commodity prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, review efforts are focused on the higher-valued properties and are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed due diligence review may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations and the Partnership's ability to make cash distributions to its unitholders, including Abraxas.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil and gas or the future operating or development costs of properties acquired;
- incorrect estimates of the oil and gas reserves attributable to a property acquired;
- unpredictable production profiles and decline rates of properties acquired;
- an inability to integrate successfully the properties acquired;
- the assumption of liabilities;
- limitations on rights to be indemnified by the seller;
- the diversion of management's attention from other business concerns; and
- losses of key operational employees at the acquired properties.

The Partnership's ability to use hedging arrangements to protect it from future oil and gas price declines will be dependent upon oil and gas prices at the time it enters into these hedging arrangements and its future levels of hedging, and as a result of its future net cash flow may be more sensitive to commodity price changes.

The Partnership has currently hedged a significant portion of its estimated oil and gas production from its net proved developed producing reserves with NYMEX-based fixed price commodity swaps. As the Partnership's derivative contracts expire, more of its future production will be sold at market prices unless it enters into further hedging arrangements. The Partnership's commodity price hedging strategy and future hedging transactions will be determined at the discretion of its general partner, which is not under any future obligation to hedge a specific portion of its production. The prices at which the Partnership hedges its production in the future will be dependent upon commodity prices at the time it enters into these arrangements, which may be substantially higher or lower than current oil and gas prices. Accordingly, the Partnership's commodity price hedging strategy may not protect it from significant declines in oil and gas prices received for its future production. Conversely, the Partnership's commodity price hedging strategy has limited and may in the future limit its ability to realize increased cash flow from commodity price increases. It is also possible that a substantially larger percentage of the Partnership's future production will not be hedged in the next few years, which would result in its oil and gas revenues becoming more sensitive to commodity price changes.

There may be conflicts of interest between Abraxas and the Partnership which could be detrimental to Abraxas.

Abraxas owns and controls the general partner of the Partnership and some of Abraxas' directors and officers are directors and executive officers of the Partnership. Conflicts of interest exist and may arise between Abraxas and the Partnership. For example, the Partnership could acquire, develop or dispose of producing properties without any obligation to offer Abraxas the opportunity to purchase or develop any of the assets. In addition, it is currently anticipated that the executive officers of the general partner, who are officers of Abraxas, will devote between 30% and 60% of their time to the Partnership's business.

The general partner of the Partnership, which is wholly- owned by Abraxas, may be removed as general partner with the consent of unitholders owning at least $66^{2}/3$% of the common units, including units beneficially owned by Abraxas.

Holders of the common units of the Partnership are currently unable to remove the general partner without its consent because Abraxas beneficially owns sufficient units to be able to prevent the removal of the general partner. The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove the general partner. If Abraxas' beneficial ownership decreases below 33 1/3%, its subsidiary could be removed as the general partner which would result in Abraxas no longer controlling the business of the Partnership.

Risks Related to Our Industry

Market conditions for oil and gas, and particularly volatility of prices for oil and gas, 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 oil and gas. Gas prices affect us more than oil prices because 65% of our production and 72% of reserves were gas at December 31, 2008. 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 oil and gas.

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

- changes in foreign and domestic supply and demand for oil and gas;
- 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.

The current global recession has had a significant impact on commodity prices and our operations. If commodity prices remain depressed our revenues, profitability and cash flow from operations may decrease which could cause us to alter our business plans, including reducing our drilling activities.

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

The process of estimating oil and gas 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, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas 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 oil and gas reserves, future net revenue from proved reserves and the PV-10 thereof for our oil and gas properties are based on the assumption that future oil and gas prices remain the same as oil and gas prices at December 31, 2008. The sales prices as of such date used for purposes of such estimates were $4.77 per Mcf of gas and $41.84 per Bbl of oil. This compares with $6.33 per Mcf of gas and $87.30 per Bbl of oil as of December 31, 2007. These estimates also assume that Abraxas and the Partnership will make future capital expenditures of approximately $134.1 million in the aggregate primarily from 2009 through 2014, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. In addition, approximately 46% of our total estimated proved reserves as of December 31, 2008 were undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. 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 cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

As required by SEC regulations, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

- supply of and demand for oil and gas;
- actual prices we receive for oil and gas;
- our actual operating costs;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flow, which is required by the SEC, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

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

Our oil and gas 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, 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 oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas 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 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 oil and gas, the demand for oilfield services has risen and the costs of these services are increasing.

Our oil and gas 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 oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances and materials produced or used in connection with oil and gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Risks Related to the Common Stock

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

Abraxas is currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. Abraxas may in the future issue its previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. In addition, under the terms of the Exchange and Registration Rights Agreement entered into in connection with the transactions completed in May 2007 and amended in October 2008, Abraxas may be required to issue additional shares of common stock. Under the terms of this amended agreement, in the event that the Partnership has not consummated its initial public offering by April 30, 2009, which we refer to as the Trigger Date, the investors will have the right to convert their common units obtained in the private placement offering into shares of common stock. Each common unit will be convertible into a number of shares of common stock equal to \$16.66 divided by the volume weighted average price of the common stock for the ten (10) business day period immediately prior to the first business day following the Trigger Date times 0.9. If stockholder approval is required for such issuance, Abraxas has agreed to call a special meeting of the stockholders within 60 days of April 30, 2009, which we refer to as the Exchange Filing Date, and the executive officers and directors of Abraxas have agreed to vote the shares of common stock then held by them in favor of such issuance. Under this agreement, Abraxas also agreed within 30 days of the Trigger Date, to prepare and file with the Securities and Exchange Commission a registration statement, which we refer to as the Exchange Registration Statement, to enable the resale of the common stock, which we refer to as the Exchange Shares, by the investors or their transferees from time to time over any national stock exchange on which the common stock is then traded, or in privately-negotiated transactions. If the Exchange Registration Statement is not declared effective by the 120th day following the Trigger Date (which period would be extended to the 180th day following the Trigger Date under certain circumstances), then in addition to any other rights the investors may have under the Exchange and Registration Rights Agreement or under applicable law, Abraxas is required to pay an amount in cash as liquidated damages and not as a penalty, equal to 1.0% of the product of \$3.83 times the number of Exchange Shares then held by such investor for each 30-day period until the Exchange Registration Statement is declared effective. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of the common stock. Abraxas may also issue additional shares of 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 the common stock.

Abraxas does not pay dividends on common stock.

Abraxas has never paid a cash dividend on its common stock and the terms of Abraxas' credit facility prohibit its ability to pay dividends on Abraxas' common stock.

Shares eligible for future sale may depress our stock price.

At February 20, 2009, Abraxas had 49,621,711 shares of common stock outstanding of which 4,334,568 shares were held by affiliates and, in addition, 2,398,778 shares of common stock were subject to outstanding options granted under certain stock option plans (of which 1,965,987 shares were vested at February 20, 2009).

All of the shares of common stock held by affiliates are restricted or controlled 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 Abraxas common stock has been volatile and could continue to fluctuate substantially.

The Abraxas common stock is traded on the NASDAQ Stock Market. The market price of the 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 oil and gas oil industry.

Abraxas may issue shares of preferred stock with greater rights than the common stock.

Subject to the rules of the NASDAQ Stock Market, Abraxas' articles of incorporation authorize its 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 the common stock. Any preferred stock that is issued may rank ahead of the common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than the common stock.

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

Abraxas' 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 its 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 continue for the common stock.

The Abraxas common stock is quoted on the NASDAQ Stock Market. While there are currently three market makers in the common stock, these market makers are not obligated to continue to make a market in the common stock. In this event, the liquidity of the common stock could be adversely impacted and a stockholder could have difficulty obtaining accurate stock quotes.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Primary Operating Areas

The following table sets forth certain information relating to our properties as of December 31, 2008.

	Producing Wells	Average Working Interest	Estimated Net Proved Reserves (MMBOE)	Year ended December 31, 2008 Net Production (MBOE)
Rocky Mountain	894	12.4%	4,935.7	404.2
Mid-Continent	602	17.1%	3,050.4	435.8
Permian Basin	236	68.0%	10,413.6	545.0
Gulf Coast	79	69.2%	6,716.0	222.0
Total	1,811	23.7%	25,115.7	1,607.0

Rocky Mountain

Our Rocky Mountain properties consist of the following:

- Northern Rockies—Our properties in the Northern Rockies are located in the Williston Basin of North Dakota, South Dakota and Montana and consist of wells that produce oil from Paleozoic-aged carbonate reservoirs from the Madison formation at 8,000 feet down to the Red River formation at 12,000 feet, including the Bakken at 9,000 feet.

- Southern Rockies—Our properties in the Southern Rockies are located in the Green River, Powder River and Uinta Basins of Wyoming, Colorado and Utah and consist of wells that produce oil from Cretaceous-aged fractured shales in the Mowry and Niobrara formation and oil and gas from Cretaceous-aged sandstones in the Turner, Muddy and Frontier formations. Well depths range from 7,000 feet down to 10,000 feet.

Mid-Continent

Our Mid-Continent properties consist of the following:

- Arkoma Basin—Our properties in the Arkoma Basin are located in Oklahoma and Arkansas and consist of wells that mainly produce gas from Hartshorne coals at 3,000 feet.

- Anadarko Basin—Our properties in the Anadarko Basin are located in Oklahoma and the Texas Panhandle and consist of wells that mainly produce gas from Pennsylvanian-aged sandstones (Atoka/Morrow) from depths of up to 18,000 feet.

- ARK-LA-TEX—Our properties in the ARK-LA-TEX region principally produce from the East Texas/North Louisiana Basins and includes wells that produce oil and gas from various formations.

Permian Basin

Our Permian Basin properties consist of the following:

- ROC Complex—Our properties in the ROC Complex are located in Pecos, Reeves and Ward Counties and consist of wells that produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet.

- Oates SW—Our properties in the Oates SW area are located in Pecos County and consist of wells that produce gas from the Devonian formation at a depth of approximately 13,500 feet.

- Eastern Shelf – Our properties in the Eastern Shelf are predominately located in Coke, Scurry and Mitchell Counties and consist of wells that produce oil and gas from the Strawn Reef formation at 5,000 to 6,000 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet Wilcox – Our properties in the Wilcox are located in Goliad, Bee and Karnes Counties and consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from 8,000 to 11,000 feet.

Gulf Coast

Our Gulf Coast properties consist of the following:

- Edwards—Our properties fields in the Edwards trend are located in Dewitt and Lavaca counties and consist of wells which produce gas from the Edwards formation at a depth of approximately 13,500 feet.

- Portilla—The Portilla field – located in San Patricio County, was discovered in 1950 by The Superior Oil Company, predecessor to Mobil Oil Corporation, and consists of wells that produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.

- Wilcox – Our properties in the Wilcox are located in Goliad, Bee and Karnes Counties and consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from 8,000 to 11,000 feet.

Exploratory and Developmental Acreage

Our principal oil and gas properties consist of producing and non-producing oil and gas leases, including reserves of oil and gas in place. The following table indicates our interest in developed and undeveloped acreage and fee mineral acreage as of December 31, 2008

	Developed Acreage (1)		**Undeveloped Acreage(2)**		**Fee Mineral Acreage (3)**		Total
	Gross Acres(4)	**Net Acres (5)**	**Gross Acres(4)**	**Net Acres (5)**	**Gross Acres(4)**	**Net Acres (5)**	Net Acres (6)
Rocky Mountain (7).....	63,225	32,903	92,317	64,376	-	-	97,279
Mid-Continent (8)........	85,812	21,949	1,957	988	-	-	22,937
Permian Basin (9)........	24,574	17,197	10,882	8,768	12,007	5,272	31,237
Gulf Coast (10)............	11,699	6,675	4,837	2,013	-	-	8,688
Total	185,310	78,724	109,993	76,145	12,007	5,272	160,141

(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 oil and gas, 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 gross acres is equivalent to 160 net acres).

(6) Includes 3,981 acres that are included in developed and undeveloped gross acres.

(7) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Rocky Mountain region as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres
Abraxas	6,814	5,401	31,977	28,598	33,999
Partnership	56,411	27,502	60,340	35,778	63,280
Total	63,225	32,903	92,317	64,376	97,279

(8) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Mid-Continent region as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres
Abraxas	679	16	-	-	16
Partnership	85,133	21,933	1,957	988	22,921
Total	85,812	21,949	1,957	988	22,937

(9) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Permian Basin region as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres(6)	Net Acres	Total Net Acres
Abraxas	14,793	11,323	9,456	7,981	12,007	5,272	24,575
Partnership	12,425	8,388	1,766	1,127	-	-	9,515
Total (a)	28,218	19,711	11,222	9,108	12,007	5,272	34,090

(a) Abraxas and the Partnership have common ownership in certain developed and undeveloped acreage with each having rights at varying depths.

(10) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Gulf Coast region as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres
Abraxas	4,969	2,757	4,008	1,828	4,585
Partnership	6,730	3,917	829	185	4,103
Total	11,699	6,675	4,837	2,013	8,688

Productive Wells

The following table sets forth our total gross and net productive wells expressed separately for oil and gas, as of December 31, 2008:

	Productive Wells (1) As of December 31, 2008			
	Oil		Gas	
	Gross (2)	Net (3)	Gross (2)	Net (3)
Rocky Mountain (4)	384.0	92.9	510.0	17.5
Mid-Continent (5)	126.0	15.3	476.0	87.8
Permian Basin (6)	171.0	131.7	65.0	28.8
Gulf Coast (7)	34.5	26.7	44.5	27.9
Total	715.5	266.6	1,095.5	162.0

(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.

(4) The following table sets forth the productive wells owned by Abraxas and the Partnership in the Rocky Mountain region as of December 31, 2008:

	Productive Wells As of December 31, 2008			
	Oil		Gas	
	Gross	Net	Gross	Net
Abraxas	21.0	18.3	12.0	1.3
Partnership	363.0	74.6	498.0	16.2
Total	384.0	92.9	510.0	17.5

(5) The following table sets forth the productive wells owned by Abraxas and the Partnership in the Mid-Continent region as of December 31, 2008:

	Productive Wells As of December 31, 2008			
	Oil		Gas	
	Gross	Net	Gross	Net
Abraxas	1.0	0.1	1.0	-
Partnership	125.0	15.2	475.0	87.8
Total	126.0	15.3	476.0	87.8

(6) The following table sets forth the productive wells owned by Abraxas and the Partnership in the Permian Basin region as of December 31, 2008:

	Productive Wells As of December 31, 2008			
	Oil		Gas	
	Gross	Net	Gross	Net
Abraxas	104.0	99.1	18.0	9.6
Partnership	67.0	32.6	47.0	19.2
Total	171.0	131.7	65.0	28.8

(7) The following table sets forth the productive wells owned by Abraxas and the Partnership in the Gulf Coast region as of December 31, 2008:

	Productive Wells As of December 31, 2008			
	Oil		Gas	
	Gross	Net	Gross	Net
Abraxas	3.0	.5	12.0	7.0
Partnership	31.5	26.2	32.5	20.9
Total	34.5	26.7	44.5	27.9

Reserves Information

Oil and gas reserves have been estimated as of December 31, 2006 and December 31, 2007 for all of our properties on those dates by DeGolyer and MacNaughton, of Dallas, Texas. DeGolyer and MacNaughton estimated reserves for properties comprising approximately 92% of the PV-10 of our oil and gas reserves as of December 31, 2008, and reserves for the remaining 8% of our properties were estimated by Abraxas Petroleum personnel because we determined that it was not practical for DeGolyer and MacNaughton to prepare reserve estimates for all of our properties because we own a large number of properties with relatively low values. DeGolyer and MacNaughton's reserve report included a total of 412 properties, which comprised approximately 92% of the PV-10 of all our properties and a total of 889 properties were included in the reserve estimates prepared by Abraxas Petroleum personnel which comprised approximately 8% of our PV-10 at December 31, 2008. Oil and gas reserves, and the estimates of the present value of future net revenues there-from, were determined based on then current prices and costs. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas 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. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company's proved reserves are located in the continental United States. Proved reserves were estimated in accordance with guidelines established by the Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, year-end prices and costs were used in estimating net cash flows.

The following table sets forth certain information regarding estimates of our oil, gas liquids and gas reserves as of December 31, 2006, December 31, 2007 and December 31, 2008.

	Estimated Proved Reserves		
	Proved Developed	**Proved Undeveloped**	**Total Proved**
As of December 31, 2006			
Oil (MBbls)	1,708	1,048	2,756
Gas (MMcf)	37,333	33,000	70,333
As of December 31, 2007			
Abraxas			
Oil (MBbls)	1,017	908	1,925
Gas (MMcf)	4,574	17,969	22,543
Partnership			
Oil (MBbls)	1,167	39	1,206
Gas (MMcf)	29,334	36,126	65,460
Total			
Oil (MBbls)	2,184	947	3,131
Gas (MMcf)	33,908	54,095	88,003

As of December 31, 2008			
Abraxas			
Oil (MBbls)	1,147	1,420	2,567
Gas (MMcf)	7,179	17,831	25,010
Partnership			
Oil (MBbls)	4,416	62	4,478
Gas (MMcf)	41,030	42,376	83,406
Total			
Oil (MBbls)	5,563	1,482	7,045
Gas (MMcf)	48,209	60,207	108,416

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

You should not assume that the present value of future net revenues referred to in this Annual Report on Form 10-K statement is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the year of the estimate, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the Company's consolidated financial statements may be used. Because we use the full cost method to account for our oil and gas 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. As of December 31, 2008, the Company's net capitalized costs of oil and gas properties exceeded the present value of its estimated proved reserves by $116.4 million ($19.2 million on Abraxas Petroleum properties and $97.1 million on the Partnership properties). These amounts were calculated considering 2008 year-end prices of $44.60 per Bbl for oil and $5.62 per Mcf for gas as adjusted to reflect the expected realized prices for our proved oil and gas reserves compared to each of the full cost pools.

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 Operations – 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 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 oil and gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

The estimates of our reserves are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the PV-10 thereof for the oil and gas properties described in this report are based on the assumption that future oil and gas prices remain the same as oil and gas prices at December 31, 2008. The average sales prices as of such date used for purposes of such estimates were $41.74 per Bbl of oil and $4.77 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $134.1 million in the aggregate primarily in the years 2009 through 2014, 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 oil and gas 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.

Oil, Gas Liquids, and Gas Production and Sales Prices

The following table presents our net oil and gas production, the average sales price per Bbl of oil and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three years ended December 31, 2008:

	2006	2007	2008
Oil production (Bbls)	200,436	196,944	549,887
Gas production (Mcf)	6,515,055	5,567,668	6,342,934
Total production (MBOE) (1) (2)	1,286	1,125	1,607
Average sales price per Bbl of oil (3)	$ 62.10	$ 65.30	$ 81.35
Average sales price per Mcf of gas (3)	$ 5.77	$ 6.46	$ 7.11
Average sales price per BOE (3)	$ 38.44	$ 41.70	$ 61.66
Average cost of production per BOE produced (1)	$ 9.12	$ 10.02	$ 16.57

(1) Oil and gas were combined by converting gas to a BOE equivalent on the basis 6 Mcf of gas to 1 Bbl of oil. Production costs include direct operating costs, ad valorem taxes and gross production taxes.

(2) The following sets forth the production for Abraxas and the Partnership in 2007 and 2008:

(3) Average sales prices include the impact of hedging activity.

	2007	2008
Abraxas :		
Oil production (Bbls)	119,188	97,729
Gas production (Mcf)	2,815,045	838,193
Total production (BOE)	588,362	237,428
Partnership :		
Oil production (Bbls)	77,756	452,158
Gas production (Mcf)	2,752,623	5,504,741
Total production (BOE)	536,527	1,369,615

Drilling Activities

The following table sets forth our gross and net working interests in exploratory and development wells drilled during the three years ended December 31, 2008:

	2006		2007		2008 (7)	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Exploratory(3)						
Productive(4)						
Oil	-		-	-	-	-
Gas	1.0	1.0	1.0	0.6	1.0	.6
Dry holes(5)	1.0	1.0	1.0	1.0	-	-
Total	2.0	2.0	2.0	1.6	1.0	.6
Development(6)						
Productive (4)						
Oil	2.0	1.2	3.0	2.6	14.0	7.2
Gas	1.0	1.0	1.0	1.0	35.0	2.2
Dry holes (5)	-	-	-	-		
Total	3.0	2.2	4.0	3.6	49.0	9.4

(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 oil or gas in an unproved area, to find a new reservoir in a field previously found to be producing oil or gas in another reservoir, or to extend a known reservoir.

(4) A productive well is an exploratory or a development well that is not a dry hole.

(5) A dry hole is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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

(7) The following sets forth drilling activity for Abraxas and the Partnership for 2008:

	Gross	Net
Exploratory:		
Gas:		
Abraxas	1.0	0.6
Partnership	-	-
Total exploratory	1.0	0.6
Development:		
Oil:		
Abraxas	7.0	6.9
Partnership	7.0	0.3
Gas:		
Abraxas	2.0	0.9
Partnership	33.0	1.3
Total development	49.0	9.4

As of February 20, 2009, we had no operated wells but several non-operated wells in process of drilling and/or completing.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, consisting of approximately 21,000 square feet. The building is owned by Abraxas, and is subject to a real estate lien note. The note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2008, $5.4 million was outstanding on the note.

Other Properties

We own 10 acres of land, an office building, workshop, warehouse and house in Sinton, Texas,, 603 acres of land and an office building in Scurry County, Texas, 50 acres of land in Lavaca County, Texas, 160 acres of land in Coke County, Texas and 11,537 acres of land in Pecos County, Texas. We also own 22 vehicles which are used in the field by employees. We own two workover rigs, which are used for servicing our wells.

Item 3. Legal Proceedings

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, 2008, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

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, 2008.

Part II

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

Market Information

Abraxas common stock began trading on the American Stock Exchange on August 18, 2000, under the symbol "ABP." On July 25, 2008, Abraxas common stock began trading on The NASDAQ Stock Market under the symbol "AXAS". The following table sets forth certain information as to the high and low sales price quoted for Abraxas' common stock on the American Stock Exchange and NASDAQ.

	Period	High	Low
2007			
	First Quarter	$ 3.47	$ 2.72
	Second Quarter	4.68	2.95
	Third Quarter	4.73	3.25
	Fourth Quarter	4.85	3.19
2008			
	First Quarter	$ 4.35	$ 3.11
	Second Quarter	5.41	3.25
	Third Quarter	5.31	2.15
	Fourth Quarter	2.48	0.65
2009	First Quarter (Through February 20, 2009)	$ 1.48	$ 0.75

Holders

As of February 20, 2009, Abraxas had 49,621,711 shares of common stock outstanding and had approximately 1,178 stockholders of record.

Dividends

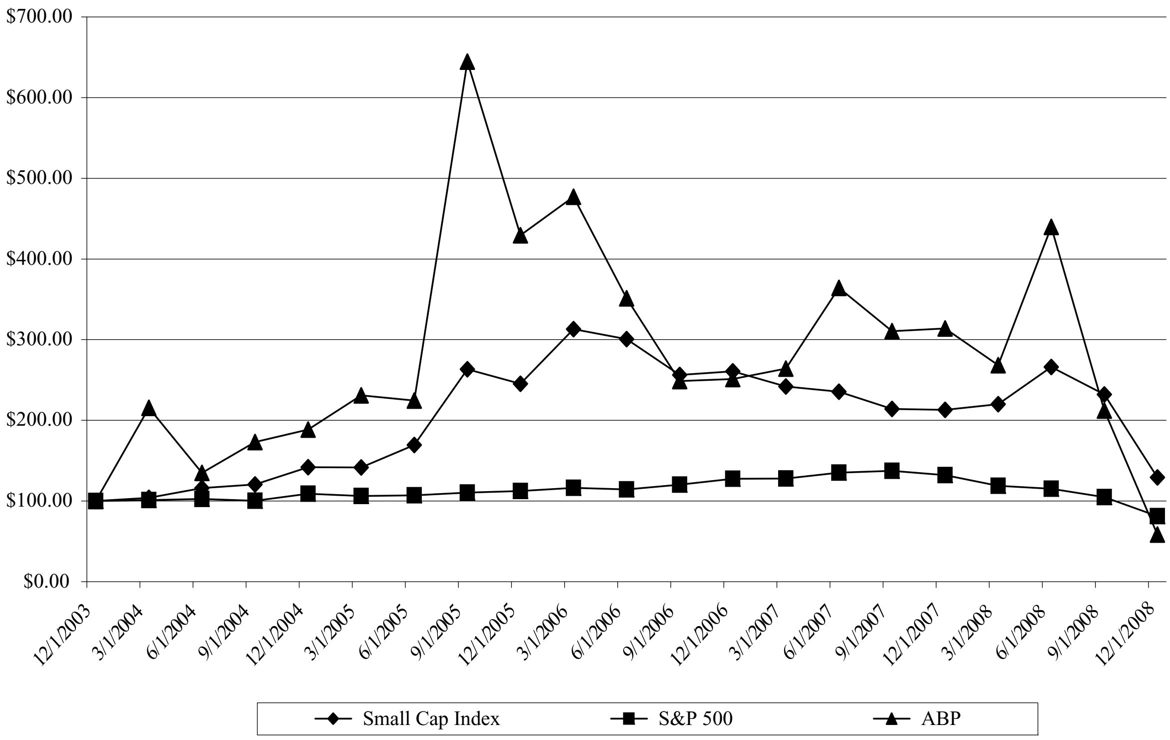
Abraxas has not paid any cash dividends on its common stock and it is not presently determinable when, if ever, Abraxas will pay cash dividends in the future. In addition, our credit facility prohibits the payment of cash dividends on the common stock. The Partnership pays distributions of available cash on a quarterly basis. During 2008, the Partnership paid distributions of $1.65 per unit. The Partnership's credit agreement permits the payment of distributions under certain conditions. 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 Abraxas' ability to pay dividends and on the Partnership's ability to pay distributions.

Performance Graph

Set forth below is a performance graph comparing yearly cumulative total stockholder return on the Abraxas common stock with (a) the monthly index of stocks included in the Standard and Poor's 500 Index and (b) the Energy Capital Solutions Index (the "ECS Index") of stocks of oil and gas exploration and production companies with a market capitalization of less than $800 million (the "Comparable Companies"). The Comparable Companies are: Brigham Exploration Co., Callon Petroleum Company, Prime Energy Corp., Gasco Energy Inc., Double Eagle Petroleum Company, Edge Petroleum Corporation, Houston American Energy Corp., CREDO Petroleum Corporation, TXCO Resources, Inc., NGAS Resources Inc., Parallel Petroleum Corporation and Toreador Resources Corp.

All of these cumulative total returns are computed assuming the value of the investment in Abraxas common stock and each index as $100.00 on December 31, 2003, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2004, 2005, 2006, 2007 and 2008.

Performance Graph



	Dec. 31, 2003	Dec. 31, 2004	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2008
ECS Index	$100.00	$141.99	$245.31	$ 260.86	$213.03	$129.35
S&P 500	$100.00	$108.99	$112.26	$ 127.55	$132.06	$ 81.23
ABP	$100.00	$188.62	$429.27	$ 251.22	$313.82	$ 58.54

The information contained above under the caption “Performance Graph” is being “furnished” to the Securities and Exchange Commission and shall not be deemed to be “soliciting material” or to be “filed” with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate it by reference into such filing.

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.

Discontinued operations in 2004 and 2005 represent the results of operations of Grey Wolf Exploration, Inc. which was a wholly-owned Canadian subsidiary of Abraxas until February 2005. In February 2005, Grey Wolf closed on an initial public offering resulting in the substantial divestiture of Abraxas’ investment in Grey Wolf.

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands except per share data)				
Total revenue - continuing operations	$ 33,854	$ 49,216	$ 51,077	$ 48,309	$ 100,310
Net income (loss)	$ 12,360(2)	$ 19,117(1)	$ 700	$ 56,702(3)	$ (52,403)(4)
Net income - discontinued operations	$ 3,323	$ 12,846(1)	$ —	$ —	$ —
Net income (loss) - continuing operations	$ 9,037	$ 6,271	$ 700	$ 56,702	$ (52,403)
Net income per common share – diluted	$ 0.32	$ 0.46	$ 0.02	$ 1.19	$ (1.07)
Weighted average shares outstanding – diluted (in thousands)	38,895	41,164	43,862	47,593	49,005
Total assets	$152,685	$121,866	$116,940	$147,119	$ 211,839
Long-term debt, excluding current maturities	$126,425	$129,527	$127,614	$ 45,900	$ 130,835
Total stockholders' equity (deficit)	$ (53,464)	$ (23,701)	$ (22,165)	$ 55,847	$ 4,658

(1) Includes gain on the sale of foreign subsidiary of $17.3 million net of non-cash tax of $6.1 million.
(2) Includes gain on debt extinguishment of $12.6 million and a deferred tax benefit of $6.1 million.
(3) Includes a gain on sale of assets of $59.4 million.
(4) Includes proved property impairment of $116.4 million.

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

The following is a discussion of our consolidated financial condition, results of 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 oil and gas. Historically, we have grown through the acquisition and subsequent development and exploration 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 number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

While we have attained positive net income from continuing operations in four of the last five years, 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 oil and gas;
- the level of total sales volumes of oil and gas;
- the availability of, and our ability to raise additional capital resources and provide liquidity to meet, cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Activities. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, price differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Recently, the prices of oil and gas have been volatile. During the first half of 2006, prices for oil and gas were sustained at record or near-record levels. Supply and geopolitical uncertainties resulted in significant price volatility during the remainder of 2006 with both oil and gas prices weakening. During 2007, oil prices remained strong while gas prices began 2007 strong but weakened during the course of the year. During the first half of 2008, prices for oil and gas were sustained at record or near-record levels, however during the second half of 2008, and subsequently, there has been a significant drop in prices. New York Mercantile Exchange (NYMEX) futures price for West Texas Intermediate (WTI) oil averaged $99.73 per barrel for 2008. WTI oil ended 2008 at $44.60 per barrel. NYMEX Henry Hub futures price for gas averaged $8.85 per million British thermal units (MMBtu) during 2008 and ended the year at $5.62. Subsequent to the end of the 2008 prices for oil and gas have continued to decline. As of February 11, 2009 the (NYMEX) futures price for West Texas Intermediate (WTI) oil was $36.22 per barrel and NYMEX Henry Hub futures price for gas was $4.57 per million British thermal units (MMBtu). If commodity prices continue to decline, our revenue and cash flow from operations could also decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. The current global recession has had a significant impact on commodity prices and our operations. If commodity prices remain depressed our revenues, profitability and cash flow from operations may decrease which could cause us to alter our business plans, including reducing our drilling activities.

The decline in commodity prices has also resulted in downward adjustments to our estimated proved reserves at December 31, 2008. For 2008 we incurred a "ceiling limitation write-down" under applicable accounting rules. Under these rules, if the net capitalized cost of oil and gas properties exceed the PV-10 of our reserves, we must charge the amount of the excess to earnings. As of December 31, 2008, the Company's net capitalized costs of oil and gas properties exceeded the present value of its estimated proved reserves by $116.4 million ($19.2 million for Abraxas Petroleum properties and $97.1 million for the Partnership properties). These amounts were calculated considering 2008 year-end prices of $44.60 per Bbl for oil and $5.62 per Mcf for gas as adjusted to reflect the expected realized prices for each of our oil and gas reserves compared to each of the full cost pools. This charge does not impact cash flow from operating activities, but does reduce our stockholder's equity and earnings. The risk that we will be required to write-down the carrying value of oil and gas properties increases when oil and gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher gas and oil prices may have increased the ceiling applicable to the subsequent period.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location,
- adjustments for BTU content; and
- gathering, processing and transportation costs.

During 2008, differentials averaged $7.07 per barrel of oil and $1.30 per Mcf of gas compared to $3.10 per barrel of oil and $1.00 per Mcf of gas in 2007. We experienced greater differentials during 2008 compared to prior years because of the increased percentage of our production from the Rocky Mountain and Mid-Continent regions which experience higher differentials than our Texas properties. Approximately 39% of our production during 2008 was from our Rocky Mountain and Mid-Continent properties. Historically, these regions have experienced wider differentials than our Permian Basin and Gulf Coast properties. As the percentage of our production from the Rocky Mountain and Mid-Continent regions increases, we expect that our consolidated price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

Under the terms of the Partnership's credit facility, Abraxas Energy Partners was required to enter into derivative contracts for specified volumes, which equated to approximately 85% of the estimated oil and gas production through December 31, 2011 from its estimated net proved developed producing reserves. At December 31, 2008 and continuing through December 2011, the Partnership has NYMEX-based fixed price commodity swaps covering approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves at volume weighted average prices of $84.23 per barrel of oil and $8.27 per Mmbtu of gas. The Partnership intends to enter into derivative contracts in the future to reduce the impact of price volatility on its cash flow. By removing a significant portion of price volatility on its future oil and gas production, the Partnership believes it will mitigate, but not eliminate, the potential effects of changing commodity prices on its cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained and in the future will sustain realized and unrealized losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our derivative contracts. For example, in 2007, the Partnership sustained an unrealized loss of $6.3 million and a realized gain of $1.9 million. In 2008, the Partnership incurred a realized loss of $9.3 million and an unrealized gain of $40.5 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative position at December 31, 2008:

Period Covered	**Product**	**Volume (Production per day)**	**Fixed Price**	
Year 2009	Gas	10,595 Mmbtu	$	8.45
Year 2009	Oil	1,000 Bbl	$	83.80
Year 2010	Gas	9,130 Mmbtu	$	8.22
Year 2010	Oil	895 Bbl	$	83.26
Year 2011	Gas	8,010 Mmbtu	$	8.10
Year 2011	Oil	810 Bbl	$	86.45

At December 31, 2008, the aggregate fair market value of our oil and gas derivative contracts was an asset of approximately $39.2 million.

Production Volumes. Because our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Approximately 85% of the estimated ultimate recovery of Abraxas' and 92% of the Partnership's, or 92% of our consolidated proved developed producing reserves as of December 31, 2008 had been produced. Based on the reserve information set forth in our reserve estimates as of December 31, 2008, Abraxas' average annual estimated decline rate for its net proved developed producing reserves is 18% during the first five years, 13% in the next five years, and approximately 7% thereafter. Based on the reserve information set forth in our reserve estimates as of December 31, 2008, the Partnership's average annual estimated decline rate for its net proved developed producing reserves is 10% during the first five years, 8% in the next five years and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While Abraxas has had some success in finding, acquiring and developing additional revenues, Abraxas has not always able to fully replace the production volumes lost from natural field declines and prior property sales. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. In 2007, however, we replaced 219% of the reserves we produced and in 2008, we replaced 555% of the reserves we produced primarily as a result of the St. Mary property acquisition in January 2008. 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, exploration and development projects. Please see "–Results of Operations–Selected Operation Data" for a presentation of our production levels for the three years.

We had capital expenditures during 2008 of $183.6 million including $123.6 million for the St. Mary property acquisition that closed in January, 2008. Capital expenditures in 2008 also included approximately $5.6 million for the acquisition of our corporate headquarters building. We have a capital budget for 2009 of approximately $32.0 million, of which $20.0 million is applicable to Abraxas and $12.0 million applicable to the Partnership. Under the terms of the Partnership credit facility, the Partnership's capital expenditures may not exceed $12.5 million prior to the termination of the Partnership's subordinated credit agreement. For more information, see "– Liquidity and Capital Resources – Long-Term Indebtedness– Subordinated Credit Agreement." The final amount of our capital expenditures for 2009 will depend on our success rate, production levels, the availability of capital and commodity prices.

The following table presents historical net production volumes for the years ended December 31, 2006, 2007 and 2008:

	Year Ended December 31,		
	2006	2007	2008
Total production (MMcfe)	7,718	6,749	9,642
Average daily production (Mcfepd)	21,144	18,492	26,346

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, Abraxas' sources of capital going forward will primarily be cash from operating activities, funding under the Credit Facility, cash on hand, distributions from the Partnership and if an appropriate opportunity presents itself, proceeds from the sale of properties. Abraxas Energy Partners' principal sources of capital will be cash from operating activities, borrowings under the Partnership Credit Facility, and sales of debt or equity securities if available to it. At December 31, 2008, Abraxas had approximately $6.5 million of availability under the Credit Facility and the Partnership had approximately $14.4 million of availability under the Partnership Credit Facility.

Additionally the Partnership's Subordinated Credit Agreement matures on July 1, 2009. The Partnership has intended to repay its indebtedness under the Subordinated Credit Agreement with proceeds from its initial public offering. However, the equity capital markets have been negatively affected in recent months. As a result, we cannot assure you that the Partnership will be successful in completing the IPO prior to the maturity of the Subordinated Credit Agreement. Abraxas Energy is currently in discussions with Société Générale to amend the existing Senior Secured Credit Facility and/or the Subordinated Credit Agreement in the event the IPO is not completed by April 30, 2009. The Partnership has also entered into discussions with other lending institutions to re-finance the $40 million currently outstanding on the Subordinated Credit Agreement. While the Company believes that there are options to this short term maturity requirement, there are no guarantees that any of these options will be successfully implemented.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and 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. At December 31, 2008, we operated properties accounting for approximately 83% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified 234 additional drilling locations (of which 109 were classified as proved undeveloped at December 31, 2008) on our existing properties, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2008, we drilled or participated in drilling 77 gross (34.8 net) wells of which 94.8% resulted in commercially productive wells.

Our future oil and gas 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 oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. In 2006, for example, Abraxas replaced only 7% of the reserves it produced. In 2007, however, we replaced 219% of our reserves, and in 2008, we replaced 555% of our reserves, primarily as the result of the St. Mary property acquisition in January 2008. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations, distributions of available cash from the Partnership to Abraxas and the amount that Abraxas is able to borrow under its credit facility and that the Partnership will be able to borrow under its credit facility will also decline. In addition, approximately 65% of Abraxas' and 39% of the Partnership's estimated proved reserves at December 31, 2008 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. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Borrowings and Interest. Abraxas Energy Partners had indebtedness of approximately $125.6 under the Partnership Credit Facility and $40 million under its Subordinated Credit Agreement as of December 31, 2008. At December 31, 2008 the Partnership had $14.4 million available under its Partnership Credit Facility. At December 31, 2008, Abraxas had availability of $6.5 million under its Credit Facility. As of December 31, 2008, there was no outstanding balance under this facility. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our numerous drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices. In order to mitigate its interest rate exposure, the Partnership entered into an interest rate swap, effective August 12, 2008, to fix its floating LIBOR-based debt. The Partnership's two-year interest rate swap arrangement for $100 million at a fixed rate of 3.367% expires on August 12, 2010. This interest rate swap was amended in February 2009 lowering the Partnership's fixed rate to 2.95%.

Results of Operations

Selected Operating Data. The following table sets forth certain of our operating data for the periods presented. Average prices reflect realized prices including the impact of hedging activities.

	Years Ended December 31, *(dollars in thousands, except per unit data.)*		
	2006	**2007**	**2008**
Operating revenue(1):			
Oil sales	$ 12,446	$ 13,633	$ 50,954
Gas sales	37,002	33,273	48,130
Rig and other	1,629	1,403	1,226
Total operating revenues	$ 51,077	$ 48,309	$ 100,310
Operating income (loss) (2)	$ 18,383	$ 15,524	$ (74,017)
Oil production (MBbls)	200.4	196.9	549.9
Gas production (MMcf)	6,515.0	5,567.7	6,342.9
Average oil sales price (per Bbl)	$ 62.10	$ 65.30	$ 81.35
Average gas sales price (per Mcf)	$ 5.77	$ 6.46	$ 7.11

(1) Revenue is after the impact of hedging activities.
(2) Operating loss in 2008 includes $116.4 million proved property impairment.

Comparison of Year Ended December 31, 2008 to Year Ended December 31, 2007

Operating Revenue. During the year ended December 31, 2008, operating revenue from oil and gas sales increased by $52.2 million from $46.9 million in 2007 to $99.1 million in 2008. The increase in revenue was due to increased production volumes in 2008 as compared to 2007 as well as higher oil and gas prices realized in 2008 as compared to 2007. The increase in production volumes contributed $29.1 million to revenue while increased commodity prices contributed $23.1 million to oil and gas production revenue.

Oil production volumes increased from 196.9 MBbls for the year ended December 31, 2007 to 549.9 MBbls for the same period of 2008. The increase in oil sales volumes was primarily due to production from properties acquired in the St. Mary acquisition that closed on January 31, 2008. Production for the year ended December 31, 2008 from these properties added 313.4 MBbls of oil. Gas production volumes increased from 5,568 MMcf for the year ended December 31, 2007 to 6,343 MMcf for the same period of

2008. The properties acquired in the St. Mary acquisition contributed 1,566 MMcf of gas production during the year, which was partially offset by natural field declines.

Average sales prices in 2008, before realized gain (loss) on derivative contracts were:

- $92.66 per Bbl of oil, and
- $ 7.59 per Mcf of gas.

Average sales prices in 2007, before realized gain (loss) on derivative contracts were:

- $69.22 per Bbl of oil, and
- $ 5.98 per Mcf of gas.

Lease Operating Expense and Production Taxes. Lease operating expense, or LOE, increased from $11.3 million in 2007 to $26.6 million in 2008. The increase in LOE was primarily due to the properties acquired from St. Mary in January of 2008 as well as an increase in ad valorem and severance taxes. Severance and ad valorem taxes increased from $3.8 million in 2007 to $9.1 million in 2008. LOE related to the properties acquired in the St. Mary property acquisition added $13.1 million to LOE during 2008. LOE on a per BOE basis for the year ended December 31, 2008 was $16.57 per BOE compared to $10.02 for the same period of 2007. The increase in per BOE cost was attributable to the increase in the number of oil wells as a result of the St. Mary acquisition, which are generally more expensive to operate than gas wells, as well as the overall increase in costs.

G&A Expense. General and administrative, or G&A expense, excluding stock based compensation increased from $5.4 million in 2007 to $5.7 million in 2008. The increase in G&A was primarily due to higher personnel expenses associated with additional staff added to manage the properties acquired from St. Mary. G&A expense on a per BOE basis was $3.56 for 2008 compared to $4.84 for the same period of 2007. The per BOE decrease was attributable to the higher G&A expense being offset by higher production volumes during 2008 as compared to 2007.

Stock-based Compensation. We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the year ended December 31, 2007 and 2008, stock based compensation was approximately $996,000 and $1.4 million respectively.

DD&A Expense. Depreciation, depletion and amortization, or DD&A, expense increased from $14.3 million in 2007 to $23.3 million in 2008. The increase in DD&A was primarily the result of increased production as well as an increase in the depletion base as a result of the St. Mary acquisition. Our DD&A expense on a per BOE basis for 2007 was $12.71 per BOE as compared to $14.53 per BOE in 2008. The increase in the per BOE basis was due to the increased production volumes in 2008 as compared to 2007.

Interest Expense. Interest expense increased to $10.5 million in 2008 compared to $8.4 million for in 2007. The increase in interest expense was primarily due to the increase in long term debt incurred by the Partnership as a result of the St. Mary acquisition. The Partnerships' debt as of December 31, 2008 was $165.6 million compared to $45.9 million as of December 31, 2007.

Income taxes. No current or deferred income tax expense or benefit has been recognized due to losses or loss carryforwards and valuation allowance, which has been recorded against such benefits.

Income (loss) from derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by SFAS 133; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Abraxas Energy Partners has entered into a series of NYMEX–based fixed price commodity swaps, the estimated unearned value of which was an asset of approximately $39.2 million as of December 31, 2008. For the year ended December 31, 2008, the Partnership realized a loss of $9.3 million related to these oil and gas derivatives, and an unrealized gain of

$40.5 million. This compares to an unrealized loss of $6.3 million and a realized gain of $1.9 million in 2007.

Other Expense. For the year ended December 31, 2008 as the result of the exchange and registration rights agreement whereby Partnership unitholders, under certain circumstances can convert their Partnership units into Abraxas Common Stock, the Company has recognized an expense of $7.4 million, including approximately $293,000 relating to shares converted during the fourth quarter and $7.1 million representing the fair value of potential conversions. This expense is included in other expense on the accompanying Consolidated Statement of Operations for the year ended December 31, 2008. See footnote 3 to the Consolidated Financial Statements for a further description of the exchange and registration rights agreement.

In August of 2008, the Partnership entered into an interest rate swap, effective August 12, 2008, to fix its floating LIBOR based debt. The Partnership's two-year interest rate swap arrangement is for $100 million at a fixed rate of 3.367%. The arrangement expires on August 12, 2010. For the year ended December 31, 2008, the Partnership realized a loss of approximately $260,000 related to this derivative and an unrealized loss of $2.7 million. The estimated unearned value of this agreement was a liability of $3.0 million as of December 31, 2008. This interest rate swap was amended in February 2009 lowering the Partnership's fixed rate to 2.95%.

Ceiling Limitation Write-down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, 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. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity. The cost ceiling represents the present value (discounted at 10%) of net cash flows from sales of future production, using commodity prices on the last day of the quarter, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the our financial statements. As of December 31, 2008, our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million ($19.2 million on Abraxas Petroleum properties and $97.1 million on the Partnership properties). These amounts were calculated considering 2008 year-end prices of $44.60 per Bbl for oil and $5.62 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves as compared to each of the full cost pools.

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

Minority interest. Minority interest represents the share of the net income (loss) of Abraxas Energy Partners for the period owned by the partners other than Abraxas Petroleum. Additionally, in accordance with generally accepted accounting principles, when cumulative losses applicable to the minority interest exceed the minority interest equity capital in the entity, such excess and any further losses applicable to the minority interest are charged to the earnings of the majority interest. If future earnings are recognized by the minority interest, such earnings will then be credited to the majority interest (Abraxas) to the extent of such losses previously absorbed and any excess earnings will increase the recorded value. For the year ended December 31, 2008, primarily as a result of the ceiling test impairment of the Partnership's oil and gas properties, losses applicable to the minority interest exceeded the minority interest equity capital by $9.3 million and, as a result, $9.3 million of the minority interest loss in excess of equity was charged to earnings and was reflected as a reduction of the loss applicable to the minority interest.

Comparison of Year Ended December 31, 2007 to Year Ended December 31, 2006

Operating Revenue. During the year ended December 31, 2007, operating revenue from oil and gas sales decreased by $2.5 million from $49.4 million in 2006 to $46.9 million in 2007. The decrease in revenue was primarily due to decreased production volumes in 2007 as compared to 2006 offset by higher oil and gas prices realized in 2007 as compared to 2006. Lower production volumes had a negative impact of $5.6 million which was partially offset by higher realized prices, excluding derivative activities, which contributed $3.1 million to oil and gas revenue for the year ended December 31, 2007.

Oil sales volumes decreased from 200.4 MBbls in 2006 to 196.9 MBbls during 2007. The decrease in oil production was primarily due to natural field declines. Gas sales volumes decreased from 6.5 Bcf in 2006 to 5.6 Bcf in 2007. This decrease was primarily due to the sale of properties in Live Oak County, Texas effective August 1, 2006, as well as natural field declines. Properties sold in 2006 contributed 182.3 MMcfe during 2006 prior to their sale. Production from a Permian Basin well drilled and brought onto production in August 2005 produced 2.2 Bcf in 2006 as compared to 1.4 Bcf in 2007. The Permian Basin well, the La Escalera 1AH well, provided approximately 20% of our Mcfe production for the year ended December 31, 2007.

Average sales prices in 2007, before realized loss on derivative contracts were:

- $69.22 per Bbl of oil, and
- $ 5.98 per Mcf of gas.

Average sales prices in 2006, before realized loss on derivative contracts were:

- $62.10 per Bbl of oil, and
- $ 5.68 per Mcf of gas.

Lease Operating Expense and Production Taxes. Lease operating expense, or LOE, decreased from $11.8 million in 2006 to $11.3 million in 2007. The decrease in LOE was primarily due to a decrease in ad valorem and severance taxes. Severance and ad valorem taxes decreased from $4.5 million in 2006 to $3.8 million in 2007. The decrease was due to revisions of values of some properties resulting in a lower ad valorem tax assessment. Excluding taxes, LOE increased from $7.3 million in 2006 to $7.4 million in 2007. This increase was due to a general increase in the cost of field services. Our LOE on a per BOE for the year ended December 31, 2007 was $10.00 per BOE compared to $9.16 per BOE in 2006. The increase on a per BOE basis was primarily due to a decrease in production volumes in 2007 as compared to 2006.

G&A Expense. General and administrative, or G&A expense, excluding stock based compensation increased from $4.2 million in 2006 to $5.4 million in 2007. The increase in G&A expense in 2007 was primarily due to new, incremental G&A costs incurred by Abraxas Energy Partners and to higher performance bonuses in 2007 as compared to 2006. Performance bonuses amounted to $162,000 in 2006, as compared to $1.1 million in 2007. Our G&A expense on a per BOE basis increased from $3.24 in 2006 to $4.84 in 2007. The increase in the per BOE cost was due to increased G&A expense in 2007 as compared to 2006 as well as decreased production volumes in 2007 as compared to 2006.

Stock-based Compensation. We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the year ended December 31, 2006 and 2007, stock based compensation was approximately $998,000 and $996,000 respectively.

DD&A Expense. Depreciation, depletion and amortization, or DD&A, expense decreased from $14.9 million in 2006 to $14.3 million in 2007. The decrease in DD&A was primarily due to increased reserves as of December 31, 2007 as compared to December 31, 2006, as well as a decrease in production volumes in 2007 as compared to 2006. Our DD&A expense on a per BOE basis for 2007 was $12.71 per BOE as compared to $11.30 per BOE in 2006. The increase in the per BOE basis was due to the decreased production volumes in 2007 as compared to 2006.

Interest Expense. Interest expense decreased to $8.4 million in 2007 compared to $16.8 million for 2006. The decrease in interest expense was due to the redemption of our outstanding senior secured notes and refinancing and repayment of our credit facility with Wells Fargo Foothill in May 2007.

*Loss on debt extinguishments***.** The loss on debt extinguishment consists primarily of the call premium and interest that was paid in connection with the refinancing and redemption of our senior secured notes in May 2007.

Income taxes. Federal income tax and state of Texas margin tax have been recognized for the year ended December 31, 2007 as a result of the gain on the sale of assets during the period. No deferred income tax expense or benefit has been recognized due to losses or loss carryforwards and valuation allowance, which has been recorded against such benefits.

Gain on sale of assets. As a result of the transactions related to the formation of Abraxas Energy Partners, we recognized a gain of $59.4 million. This gain was calculated based on the requirements of Staff Accounting Bulletin 51, (Topic 5H) based on the fact that we elected gain treatment as a policy and the transaction met the following criteria: (1) there were no additional broad corporate reorganizations contemplated; (2) there was not a reason to believe that the gain would not be realized, since there is no additional capital raising transaction anticipated nor was there a significant concern about the new entity's ability to continue in existence; (3) the share price of capital raised in the private placement was objectively determined; (4) no repurchases of the new subsidiary's units are planned; and (5) we acknowledge that we will consistently apply the policy, and any future transactions that might result in a loss must be recorded as a loss in the income statement.

Income (loss) from derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by SFAS 133; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Abraxas Energy Partners has entered into a series of NYMEX–based fixed price commodity swaps, the estimated unearned value of which was approximately $(9.1) million as of December 31, 2007. For the year ended December 31, 2007, we realized a gain on these derivative contracts of $1.9 million. As of December 31, 2007 we incurred unrealized losses on derivative contracts of $6.3 million.

Minority interest. Minority interest represents the share of the net income (loss) of Abraxas Energy Partners for the period owned by the partners other than Abraxas Petroleum. For the year ended December 31, 2007, the minority interest in the net loss of the Partnership was approximately $1.8 million.

Liquidity and Capital Resources

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

- the development of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional oil and gas 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.

Abraxas' sources of capital going forward will primarily be cash from operating activities, funding under its credit facility, distributions from the Partnership 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. The Partnership's principal sources of capital will be cash from operating activities, borrowings under the Partnership Credit Facility, and sales of debt or equity securities if available to it.

Working Capital (Deficit). At December 31, 2008 our current liabilities of $59.3 million exceeded our current assets of $33.3 million resulting in working capital deficit of $26.0 million. This compares to working capital of $11.3 million as of December 31, 2007. Significant components of current liabilities as of December 31, 2008 consisted of trade payables of $10.7 million, revenues due third parties of $3.2 million, other accrued liabilities of $2.3 million, current derivative liabilities of $3.0 million and current maturities of long-term debt of $40.1 million, primarily related to the Partnership's Subordinated Credit Agreement. The Partnership has intended to repay its indebtedness under the Subordinated Credit Agreement with proceeds from its initial public offering. However, the equity capital markets have been negatively affected in recent months. As a result, we cannot assure you that the Partnership will be successful in completing the IPO prior to the maturity of the Subordinated Credit Agreement. The Partnership has entered into discussions with the lending institutions to either extend or refinance the $40.0 million in debt under its Subordinated Credit Agreement, due July 1, 2009. There can be no assurance that the Partnership will be successful in such negotiations.

Capital Expenditures. Capital expenditures related to our continuing operations in 2006, 2007 and 2008 were $26.3 million, $26.9 million and $183.6 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2008.

	Year Ended December 31,		
	2006	**2007**	**2008**
	(dollars in thousands)		
Expenditure category:			
Exploration/Development	$ 26,117	$ 16,793	$ 49,610
Acquisition	-	10,000	127,671
Facilities and other	229	115	6,351
Total	$ 26,346	$ 26,908	$ 183,632

During 2006 and 2007, capital expenditures were primarily for the development of existing properties and a deposit for the St. Mary property acquisition that closed in January 2008. During 2008 capital expenditures included $127.7 million for the acquisition of the St. Mary properties and other smaller acquisitions, as well as the development of our properties. We anticipate making capital expenditures for 2009 of $20.0 million. These anticipated expenditures are subject to adequate cash flow from operations and availability under our revolving credit facility. The Partnership anticipates making capital expenditures for 2009 of $12.0 million which will be used primarily for the development of its current properties. Additionally, while the Subordinated Credit Agreement is outstanding, the Partnership's capital expenditures are limited to $12.5 million. These anticipated expenditures are subject to adequate cash flow from operations, availability under Abraxas' and the Partnership's Credit Facilities and, in Abraxas' case, distributions of available cash from the Partnership. 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 the acquisition of producing properties if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on market conditions and other related economic factors. There has been a significant decline in oil and gas prices since the second quarter of 2008. Should the prices of oil and gas 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 oil and gas 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,		
	2006	2007	2008
	(dollars in thousands)		
Net cash provided by operating activities	$ 15,561	$ 18,332	$ 43,387
Net cash used in investing activities	(14,102)	(26,908)	(173,944)
Net cash (used in) provided by financing activities	(1,458)	27,469	113,545
Total	$ 1	$ 18,893	$ (17,012)

Operating activities for the year ended December 31, 2008 provided $43.4 million in cash compared to providing $18.3 million in 2007. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds, including the non–cash proved property impairment of $116.4 million. Financing activities provided $113.5 million for the year ended December 31, 2008 as compared to providing $27.5 million in 2007. Most of the funds provided in 2008 were the proceeds of long-term borrowing in connection with the acquisition of the St. Mary properties in January 2008. Investing activities used $173.9 million in 2008 including $127.7 million for the acquisition of oil and gas properties as well as the development of our current properties.

Operating activities for the year ended December 31, 2007 provided $18.3 million in cash compared to providing $15.6 million in the same period in 2006. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Financing activities provided $27.5 million for the year ended December 31, 2007 compared to using $1.5 million for the same period of 2006. Most of the funds provided in 2007 were proceeds from the issuance of common stock, proceeds from the sale of common units of the Partnership and proceeds from the Partnership's and Abraxas' credit facilities. In 2006, most of the funds used were for net reductions in long-term borrowings from our revolving line of credit. Investing activities used $26.9 million during the year ended December 31, 2007 compared to using $14.1 million for the same period of 2006. Investing activities in 2007 included $16.9 million for the development of our existing properties and $10 million for the St. Mary property acquisition that was completed in January 2008.

Operating activities for the year ended December 31, 2006 provided us with $15.6 million of cash. Expenditures in 2006 of approximately $26.3 primarily for the development of oil and gas properties offset by proceeds from the sale of oil and gas properties of $12.2 million. Financing activities used $1.5 million during 2006, of which $20.4 million was provided from long-term borrowing offset by $22.4 million of payments on long-term debt.

Future Capital Resources. Abraxas' sources of capital going forward will primarily be cash from operating activities, funding under the Credit Facility, cash on hand, distributions from the Partnership and if an appropriate opportunity presents itself, proceeds from the sale of properties. Abraxas Energy Partners' principal sources of capital will be cash from operating activities, borrowings under the Partnership Credit Facility, and sales of debt or equity securities, if available to it. The credit markets are undergoing significant volatility and capacity constraints. Many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the credit market. Our exposure to the current credit market crisis includes our Credit Facility, the Partnership Credit Facility and the Subordinated Credit Agreement and counterparty performance risk.

Our Credit Facility and the Partnership Credit Facility are each subject to a borrowing base. Our Credit Facility matures on June 27, 2011 and the Partnership Credit Facility matures on January 31, 2013. Should current credit market volatility be prolonged for several years, future extensions of credit may contain terms that are less favorable than those in our Credit Facility and the Partnership Credit Facility. The Subordinated Credit Agreement matures on July 1, 2009. The Partnership has intended to re-pay the amounts due under this agreement with the proceeds of the initial public offering. However, the equity capital markets have been negatively affected in recent months. As a result, we cannot assure you that the Partnership will be successful in completing the IPO prior to the maturity of the Subordinated Credit Agreement. In addition, the Partnership's failure to receive $20.0 million of proceeds from an equity issuance on or prior to April 30, 2009 would be an event of default under the Subordinated Credit Agreement.

Current market conditions also elevate concern over counterparty risks related to our commodity derivative instruments. The Partnership has all of its commodity derivative instruments with one major financial institution. Should this financial counterparty not perform, we may not realize the benefit of some of our hedges under lower commodity prices. Although these derivative instruments as well as our Credit Facility and the Partnership Credit Facility expose us to credit risk, we monitor the creditworthiness of our counterparty, and we are not currently aware of any inability on the part of our counterparty to perform under our contracts. However, we are not able to predict sudden changes in the credit worthiness of our counterparty.

Oil and gas prices are also volatile and have declined significantly during the second half of 2008 and have continued to decline since the end of the year. Further, the decline in commodity prices has not been accompanied by a relative decline in the prices of goods and services that we use to drill, complete and operate our wells. The decline in commodity prices has reduced our cash flow from operations from what it would have otherwise been. To mitigate the impact of lower commodity prices on our cash flows, we have entered into commodity derivative contracts. As the result of the global recession, commodity prices may stay depressed or reduce further, thereby causing a prolonged downturn, which could further reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans.

Our cash flow from operations will also depend upon the volume of oil and gas that we produce. Unless we otherwise expand reserves, our production volumes may decline as reserves are produced. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. In 2007 we replaced 219% of the reserves we produced and in 2008, we replaced 555% of the reserves we produced, primarily as the result of the St. Mary property acquisition in January 2008. In the future, if an appropriate opportunity presents itself, we may sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration 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 oil and gas reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations, distributions from the Partnership and the amount that we are able to borrow under our credit facilities will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 65% of Abraxas Petroleum's and 39% of the Partnership's total estimated proved reserves at December 31, 2008 were undeveloped. For the year ended December 31, 2008, we expended approximately $49.6 million on our exploration and development activities s and continued general well maintenance and work-overs utilizing our own work-over rigs

Contractual Obligations. We are committed to making cash payments in the future on our long-term debt.

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, 2008.

		Payments due in:			
Contractual Obligations (dollars in thousands)	**Total**	**2009**	**2010-2011**	**2012-2013**	**Thereafter**
Long-term debt (1)	$170,969	$40,134	$ 295	$ 125,936	$ 4,604
Interest on long-term debt (2)	11,895	4,584	6,261	618	432
Total	$182,864	$44,718	$ 6,556	$ 126,554	$ 5,036

(1) These amounts represent the balances outstanding under the Partnership Credit Facility, the Partnership's Subordinated Credit Agreement and Abraxas' mortgage on its headquarters building. 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.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2008, our reserve for these obligations totaled $9.9 million for which no contractual commitment exist. For additional information relating to this obligation, see Note 1 of Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2008, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

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, 2008 we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, exploration, development and production of oil and 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

Long-term indebtedness consisted of the following:

	December 31, 2008	December 31, 2007
	(in thousands)	
Partnership credit facility	$ 125,600	$ 45,900
Partnership subordinated credit agreement	40,000	—
Real estate lien note	5,369	—
	170,969	45,900
Less current maturities	(40,134)	—
	$ 130,835	$ 45,900

Abraxas Senior Secured Credit Facility. On June 27, 2007, Abraxas entered into a new senior secured revolving credit facility, which we refer to as the Credit Facility. The Credit Facility has a maximum commitment of $50.0 million. Availability under the Credit Facility is subject to a borrowing base. The borrowing base under the Credit Facility, which is currently $6.5 million, is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, may make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we may also request one redetermination during any six-month period between scheduled redeterminations. The lenders may also make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our current borrowing base. Our borrowing base at December 31, 2008 of $6.5 million was determined based upon our reserves at June 30, 2008. Our borrowing base can never exceed the $50.0 million maximum commitment amount. Outstanding amounts under the Credit Facility will bear interest at (a) the greater of the reference rate announced from time to time by Société Générale, and (b) the Federal Funds Rate plus 0.5% of 1%, plus in each case, (c) 0.5% - 1.5% depending on utilization of the borrowing base, or, if Abraxas elects, at the London Interbank Offered Rate plus 1.5% - 2.5%, depending on the utilization of the borrowing base. Subject to earlier termination rights and events of default, the Credit Facility's stated maturity date is June 27, 2011. Interest will be payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances.

Abraxas is permitted to terminate the Credit Facility, and may, from time to time, permanently reduce the lenders' aggregate commitment under the Credit Facility in compliance with certain notice and dollar increment requirements.

Each of Abraxas' subsidiaries other than the Partnership, Abraxas General Partner, LLC and Abraxas Energy Investments, LLC has guaranteed Abraxas' obligations under the Credit Facility on a senior secured basis. Obligations under the Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of Abraxas' and the subsidiary guarantors' material property and assets.

Under the Credit Facility, Abraxas is subject to customary covenants, including certain financial covenants and reporting requirements. The Credit Facility requires Abraxas to maintain a minimum current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio (generally defined as the ratio of consolidated EBITDA to consolidated interest expense as of the last day of such quarter) of not less than 2.50 to 1.00.

In addition to the foregoing and other customary covenants, the Credit Facility contains a number of covenants that, among other things, will restrict Abraxas' ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an "arms-length" basis;
- make any change in the principal nature of its business; and
- permit a change of control.

The 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.

Amended and Restated Partnership Credit Facility. On May 25, 2007, the Partnership entered into a senior secured revolving credit facility which was amended and restated on January 31, 2008 and further amended on January 16, 2009, which we refer to as the Partnership Credit Facility. The Partnership Credit Facility has a maximum commitment of $300.0 million. Availability under the Partnership Credit Facility is subject to a borrowing base. The borrowing base under the Partnership Credit Facility, which is currently $140.0 million, is determined semi-annually by the lenders based upon the Partnership's reserve reports, one of which must be prepared by the Partnership's independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of the Partnership's proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, may make one additional borrowing base redetermination during any six-month period between scheduled redeterminations. The lenders may also make a redetermination in connection with any sales of producing properties with a market value of 5% or more of the Partnership's current borrowing base. The Partnership's current borrowing base of $140.0 million was determined based upon its reserves at June 30, 2008. The borrowing base can never exceed the $300.0 million maximum commitment amount. During the period beginning on January 16, 2009 and ending on the date that the Subordinated Credit Agreement is terminated, outstanding amounts under the Partnership Credit Facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR rate plus, in each case, (b) 1.5% - 2.5%, depending on the utilization of the borrowing base, or, if the Partnership elects, at the London Interbank Offered Rate plus 2.5% - 3.5% depending on the utilization of the borrowing base. After the termination of the Subordinated Credit Agreement, outstanding amounts under the Partnership Credit Facility will bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR rate plus, in each case, (b) 1.0% - 2.0%, depending on the utilization of the borrowing base, or, if the Partnership elects, at the London Interbank Offered Rate plus 2.0% - 3.0% depending on the utilization of the borrowing base. At January 16, 2009, the interest rate on the Partnership Credit Facility was 3.8%. Subject to earlier termination rights and events of default, the Partnership Credit Facility's stated maturity date is January 31, 2013. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. The Partnership is permitted to terminate the Partnership Credit Facility, and under certain circumstances, may be required, from time to time, to permanently reduce the lenders' aggregate commitment under the Partnership Credit Facility.

Each of the general partner of the Partnership, Abraxas General Partner, LLC, which is a wholly-owned subsidiary of Abraxas and which we refer to as the GP, and Abraxas Operating, LLC, which is a wholly-owned subsidiary of the Partnership and which we refer to as the Operating Company, has guaranteed the Partnership's obligations under the Partnership Credit Facility on a senior secured basis. Obligations under the Partnership Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the property and assets of the GP, the Partnership and the Operating Company, other than the GP's general partner units in the Partnership.

Under the Partnership Credit Facility, the Partnership is subject to customary covenants, including certain financial covenants and reporting requirements. The Partnership Credit Facility requires the Partnership to maintain a minimum current ratio as of the last day of each quarter of 1.00 to 1.00 and an interest coverage ratio (defined as the ratio of consolidated EBITDA to consolidated interest expense) as of the last day of each quarter of not less than 2.50 to 1.00. The Partnership Credit Facility required it to enter into derivative contracts for specific volumes, which equated to approximately 85% of the estimated oil and gas production from its net proved developed producing reserves through December 31, 2011. The Partnership entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011.

Under the terms of the Partnership Credit Facility, the Partnership may make cash distributions if, after giving effect to such distributions, the Partnership is not in default under the Partnership Credit Facility, there is no borrowing base deficiency and provided that (a) no such distribution shall be made using the proceeds of any advance unless the unused portion of the amount then available under the Partnership Credit Facility is greater than or equal to 10% of the lesser of the Partnership's borrowing base (which at January 16, 2009 was $140.0 million) or the total commitment amount of the Partnership Credit Facility (which at January 16, 2009 was currently $300.0 million) at such time, (b) with respect to the cash distribution scheduled to be made on or about May 15, 2009 attributable to the first quarter of 2009, no such distribution shall be made unless (i) the sum of unrestricted cash and the unused portion of the amount then available under the Partnership Credit Facility after giving effect to such distribution exceeds $20.0 million, or (ii) the Subordinated Credit Agreement shall have terminated and (c) no cash distribution shall exceed $0.44 per unit per quarter while the Subordinated Credit Agreement is outstanding. Additionally, while the Subordinated Credit Agreement is outstanding, the Partnership's capital expenditures are limited to $12.5 million.

In addition to the foregoing and other customary covenants, the Partnership Credit Facility contains a number of covenants that, among other things, will restrict the Partnership's ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates;
- make any change in the principal nature of its business; and
- permit a change of control.

. The Partnership 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 including the Subordinated Credit Agreement described below, bankruptcy and material judgments and liabilities.

Subordinated Credit Agreement

On January 31, 2008, the Partnership entered into a subordinated credit agreement which was amended on January 16, 2009, which we refer to as the Subordinated Credit Agreement. The Subordinated Credit Agreement has a maximum commitment of $40.0 million. Outstanding amounts under the Subordinated Credit Agreement bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5% and (3) a rate determined by Société Générale as the daily one-month LIBOR Offered Rate, plus in each case (b) 7.50% or, if the Partnership elects, at the greater of (a) 2.0% and (b) at the London Interbank Offered Rate, in each case, plus 8.50%. At January 16, 2009 the interest rate on the Subordinated Credit Agreement was 10.5%. Principal payments under the Subordinated Credit Agreement must be made on May 14, 2009 in an amount, which we refer to as the May 14, 2009 Payment Amount, equal to the lesser of the amount of cash distributed to Abraxas Energy Investments, LLC, a wholly-owned subsidiary of Abraxas Petroleum, on or about February 14, 2009 and $2.25 million with the balance due on the maturity date. The maturity date may be accelerated if any limited partner of the Partnership, other than Perlman Value Partners, exercises its right to convert its limited partner units into shares of common stock of Abraxas Petroleum pursuant to the terms of the Exchange and Registration Rights Agreement dated May 25, 2007, as amended, among Abraxas Petroleum, the Partnership and the purchasers named therein. As a result of the amendment to the Subordinated Credit Agreement, the date on which the purchasers, if the Partnership's initial public offering has not been consummated prior to that date, may first exchange their Partnership units for Abraxas Petroleum common stock is April 30, 2009. Subject to earlier termination rights and events of default, the Subordinated Credit Agreement's stated maturity date is July 1, 2009. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. The Partnership is permitted to terminate the Subordinated Credit Agreement, and under certain circumstances, may be required, from time to time, to make prepayments under the Subordinated Credit Agreement.

Each of the GP and the Operating Company has guaranteed the Partnership's obligations under the Subordinated Credit Agreement on a subordinated secured basis. Obligations under the Subordinated Credit Agreement are secured by subordinated security interests, subject to certain permitted encumbrances, in all of the property and assets of the Partnership, GP, and the Operating Company, other than the GP's general partner units in the Partnership.

Under the Subordinated Credit Agreement, the Partnership is subject to customary covenants, including certain financial covenants and reporting requirements. The Subordinated Credit Agreement requires the Partnership to maintain a minimum current ratio as of the last day of each quarter of 1.00 to 1.00 and an interest coverage ratio (defined as the ratio of consolidated EBITDA to consolidated interest expense) as of the last day of each quarter of not less than 2.50 to 1.00. The Partnership Credit Facility required it to enter into derivative contracts for specific volumes, which equated to approximately 85% of the estimated oil and gas production from its net proved developed producing reserves through December 31, 2011. The Partnership entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011.

In addition to the foregoing and other customary covenants, the Subordinated Credit Agreement contains a number of covenants that, among other things, will restrict the Partnership's ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates;
- make any change in the principal nature of its business; and
- permit a change of control.

The Subordinated Credit Agreement 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 the Partnership Credit Facility, bankruptcy and material judgments and liabilities. In addition, as a result of the amendment to the Subordinated Credit Agreement, two events of default were added to the Subordinated Credit Agreement. The first event of default would occur if the Partnership fails to receive a letter of credit, which we refer to as the APC L/C, in its favor from Abraxas Petroleum equal to the May 14, 2009 Payment Amount, the Partnership fails to draw on the APC L/C on or before May 14, 2009 or the Partnership fails to use the proceeds of the APC L/C to make the principal payment due on May 14, 2009. This event of default would not occur in the event that the Partnership repays the principal amount due on May 14, 2009 with funds received from Abraxas Petroleum. The Partnership and Abraxas Petroleum have agreed that upon the occurrence of such a payment or the Partnership's drawing on the APC L/C that, in consideration thereof, the Partnership would issue a number of additional units to Abraxas Petroleum determined by dividing the May 14, 2009 Payment Amount by 110% of the average trading yields of comparable E&P MLPs based on the closing market price on May 14, 2009 multiplied by the most recent quarterly distribution paid or declared by the Partnership times four. The other event of default would occur if the Partnership fails to receive $20.0 million of proceeds from an equity issuance on or before April 30, 2009.

Real Estate Lien Note

On May 9, 2008 the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a new building to serve as its corporate headquarters. This note was refinanced in November 2008. The new note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2008, $5.4 million was outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. Under the terms of the Partnership Credit Facility, Abraxas Energy Partners was required to enter into hedging arrangements for specified volumes, which equated to approximately 85% of the estimated oil and gas production through December 31, 2011 from its net proved developed producing reserves.

In order to mitigate its rate exposure, the Partnership entered into an interest rate swap, effective August 12, 2008, to fix its floating LIBOR based debt. Our 2-year interest rates swap arrangement is for $100 million at a fixed rate of 3.367%. The arrangement expires on August 12, 2010. The interest rate swap was amended in February 2009 lowering the Partnership's fixed rate from 3.367% to 2.95%.

See "—Quantitative and Qualitative Disclosures about Market Risk—Hedging Sensitivity" for further information.

Net Operating Loss Carryforwards

At December 31, 2008, we had, subject to the limitation discussed below, $194.4 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2028 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 $47.2 million and $60.8 million for deferred tax assets at December 31, 2007 and 2008, 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.

Abraxas performs general and administrative services for the Partnership, such as accounting, finance, land and engineering. The Partnership currently pays us $2.6 million per year, which included an adjustment of $1.1 million annually as a result of the St. Mary Acquisition, for performing these general and administrative services. The amount of reimbursement is subject to annual adjustments for inflation and acquisition or other expansion adjustments.

Pursuant to our operating agreements, the Partnership is required to reimburse us for all direct and indirect expenses associated with operating our wells. Operating expenses are the costs incurred in the operation of producing properties. Expenses for utilities, direct labor, water injection and disposal, production taxes and materials and supplies comprise the most significant portion of our operating expenses. Operating expenses do not include general and administrative expenses.

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

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years, most recently in 2002 and the current year. Our oil and gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from impairment testing procedures associated with the full cost method of accounting as discussed below.

Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves 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 oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are depressed. 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 gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

Estimates of Proved Oil and Gas Reserves. Estimates of our proved reserves included in this report are prepared in accordance with U.S. generally accepted accounting principles ("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 were predominately 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.

Accounting for Derivatives. We use commodity price derivative contracts to limit our exposure to fluctuations in oil and gas prices and interest rate swaps to hedge our interest rate risk. Fluctuations in the market value are recognized in earnings in the current period. 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. We have elected out of hedge accounting as prescribed by SFAS 133 – accordingly all of our derivative contracts are required to be recorded at fair value on our balance sheet, while changes in the fair value of our derivative contracts are recognized in earnings in the current period. Due to the volatility of oil and gas prices and, to a lesser extent, interest rates, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2007 and 2008, the net market value of our oil and gas derivatives was a liability of $9.1 million and a net asset of $39.2 million, respectively. The market value of our interest rate derivative was a liability of $3.0 million at December 31, 2008.

Share-Based Payments. We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Additional information about management's assumptions can be found in footnote 6 to the consolidated financial statements. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the years ended December 31, 2006, 2007 and 2008, stock based compensation was approximately $998,000; $996,000 and $1.4 million respectively.

Recent Accounting Pronouncements

Fair Value Measurements (SFAS No. 157) — In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The FASB agreed to defer the effective date of Statement 157 for one year for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. There is no deferral for financial assets and financial liabilities. See Note 13 to the consolidated financial statements for more information regarding this pronouncement.

The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115 (SFAS No. 159) — In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the implementation of SFAS No. 159 to have a material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in the equity in the consolidated financial statements separately from the parent's equity. Subsequent changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest, are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. Due to our investment in Abraxas Energy Partners, the adoption of SFAS No. 160 could have a material impact on our financial position and results of operations, however we do not believe that it will have a material impact on our cash flows.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a "business" and a "business combination" have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. We cannot predict the impact that the adoption of SFAS No. 141(R) will have on our financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2008.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Enhanced disclosures to improve financial reporting transparency are required and include disclosure about the location and amounts of derivative instruments in the financial statements, how derivative instruments are accounted for and how derivatives affect an entity's financial position, financial performance and cash flows. A tabular format including the fair value of derivative instruments and their gains and losses, disclosure about credit risk-related derivative features and cross-referencing within the footnotes are also new requirements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application and comparative disclosures encouraged, but not required. We have not yet adopted SFAS No. 161. We do not believe that SFAS No. 161 will have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles.” The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are prepared in conformance with generally accepted accounting principles. Unlike Statement on Auditing Standards (SAS) No. 69, “The Meaning of Present in Conformity With GAAP,” FAS No. 162 is directed to the entity rather than the auditor. The statement is effective 60 days following the SEC’s approval of the Public Company Accounting Oversight Board (PCAOB) amendments to AU Section 411, “The Meaning of Present Fairly in Conformity with GAAP,” and is not expected to have any impact on the Company’s results of operations, financial condition or liquidity.

On December 29, 2008, the Securities and Exchange Commission adopted rule changes to modernize its oil and gas reporting disclosures. The changes are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves.

The updated disclosure requirements are designed to align with current practices and changes in technology that have taken place in the oil and gas industry since the adoption of the original reporting requirements more than 25 years ago.

New disclosure requirements include:

- Permitting the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes.
- Enabling companies to additionally disclose their probable and possible reserves to investors. Currently, the rules limit disclosure to only proved reserves.
- Allowing previously excluded resources, such as oil sands, to be classified as oil and gas reserves.
- Requiring companies to report on the independence and qualifications of a preparer or auditor and requiring companies to file reports when a third party is relied upon to prepare reserve estimates or conduct a reserves audit.
- Requiring companies to report oil and gas reserves using an average price based upon the prior 12-month period – rather than the year-end price – to maximize the comparability of reserve estimates among companies and mitigate the distortion of the estimates that arises when using a single pricing date.

The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending on or after December 31, 2009.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and equity earnings and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil, 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 oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global political and economic conditions. Historically, prices received for oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2008, a 10% decline in oil and gas, prices would have reduced our operating revenue and cash flow by approximately $10.0 million for the year.

Hedging Activity and Sensitivity

To achieve more predictable cash flow, we reduce our exposure to fluctuations in the prices of oil and gas. We have and may continue to enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production. The Partnership Credit Facility required the Partnership to enter into hedging arrangements on specified volumes, which equated to approximately 85% of the estimated projected oil and gas production from its estimated pro forma net proved developed producing reserves through December 31, 2011. The Partnership has entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011 at volume weighted average prices of $84.23 per barrel of oil and $8.27 per MMbtu of gas.

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. We record our derivative instruments using the same method, 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 income.

At December 31, 2008, the Partnership had the following derivative contracts in place:

Period Covered	Product	Volume (Production per day)	Fixed Price
Year 2009	Gas	10,595 Mmbtu	$8.45
Year 2009	Oil	1,000 Bbl	$83.80
Year 2010	Gas	9,130 Mmbtu	$8.22
Year 2010	Oil	895 Bbl	$83.26
Year 2011	Gas	8,010 Mmbtu	$8.10
Year 2011	Oil	810 Bbl	$86.45

We expect to sustain realized and unrealized gains and losses as a result of these derivative contracts. For the year ended December 31, 2007, we recognized a realized gain of $1.9 million and an unrealized loss of $6.3 million, and for the year ended December 31, 2008, we recognized a realized loss of $9.3 million and an unrealized gain of $40.5 million on our derivative contracts. The realized losses for the year ended December 31, 2008 were the result of the contract prices for oil being significantly less than current market prices. The unrealized gains were the result of the drastic drop in commodity prices during the second half of 2008 resulting in the contract prices for oil and gas being greater that the market price. On December 31, 2008, NYMEX futures prices were $44.60 per barrel of oil and $5.62 per Mmbtu of gas. We expect to continue to sustain realized and unrealized gains on our derivative contracts if market prices continue to be less than our contract prices.

Interest rate risk

The Partnership is subject to interest rate risk associated with borrowings under the Partnership Credit Facility and the Subordinated Credit Agreement. At December 31, 2008, the Partnership had $125.6 million in outstanding indebtedness under the Partnership Credit Facility. Outstanding amounts under the Partnership Credit Facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR rate plus, in each case, (b) 1.5% - 2.5%, depending on the utilization of the borrowing base, or, if the Partnership elects, at the London Interbank Offered Rate plus 2.5% - 3.5% depending on the utilization of the borrowing base. At December 31, 2008, the interest rate on the facility was 3.2%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.3 million on an annual basis. In addition the Partnership had $40.0 million in outstanding indebtedness under the Subordinated Credit Agreement. Outstanding amounts under the Subordinated Credit Agreement bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5% and (3) a rate determined by Société Générale as the daily one-month LIBOR Offered Rate, plus in each case (b) 7.50% or, if the Partnership elects, at the greater of (a) 2.0% and (b) at the London Interbank Offered Rate, in each case, plus 8.50%. At December 31, 2008 the interest rate on the facility was 7.7%. For every percentage point that the rate rises, our interest expense would increase by approximately $400,000 on an annual basis. In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating

LIBOR based debt. The arrangement expires on August 12, 2010. The interest rate swap was amended in February 2009 lowering the Partnership's fixed rate from 3.367% to 2.95%.

Item 8. Financial Statements and Supplementary Data

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

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer believe that the disclosure controls and procedures as of December 31, 2008 were effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and are effective to ensure that information required to be disclosed by us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and implemented by the Company's Board of Directors, management and other personnel, 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 and 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.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by BDO Seidman LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2008 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART II

Item 10. Directors, Executive Officers and Corporate Governance

There is incorporated in this Item 10 by reference that portion of our definitive proxy statement for the 2009 Annual Meeting of Stockholders which appears therein under the caption "Election of Directors – Board of Directors and Executive Officers," "– Code of Ethics" and "– Committees of the Board of Directors."

Audit Committee and Audit Committee Financial Expert

The Audit Committee of our board of directors consists of C. Scott Bartlett, Jr., Franklin A. Burke and Paul A. Powell. 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 NASDAQ Stock Market and Item 407(a) of Regulation S-K. 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 NASDAQ 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 2008.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2009 Annual Meeting of Stockholders which appears therein under the captions "Election of Directors – Committees of the Board of Directors" and "Executive Compensation", except the material under the caption "Compensation Committee Report on Executive Compensation."

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 2009 Annual Meeting of Stockholders which appears therein under the caption "Securities Holdings of Principal Stockholders, Directors, Nominees and Officers."

Item 13. Certain Relationships and Related Transactions, and Director Independence

There is incorporated in this Item 13 by reference that portion of our definitive proxy statement for the 2009 Annual Meeting of Stockholders which appears therein under the captions "Certain Transactions" and "Election of Directors – Board Independence."

Item 14. Principal Accountants Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2009 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 on Form 10-K (Filed April 2, 2001).
3.6	Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to Abraxas' Current Report on Form 8-K. on November 17, 2008).
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).
*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 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).

*10.3 Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.4 to our Annual Report on Form 10-K filed March 14, 2007).

*10.4 Employment Agreement between Abraxas and Robert L. G. Watson. (Filed as Exhibit 10.19 to the Registration Statement on Form S-1, No. 333-95281 (the "2000 S-1 Registration Statement")).

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

*10.6 Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the Registration Statement on Form S-3, No. 333-127480 (the "S-3 Registration Statement")).

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

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

*10.9 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).

*10.10 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).

*10.11 Abraxas Petroleum Corporation Senior Management Incentive Bonus Plan 2006. (Filed as Exhibit 10.17 to Annual Report on Form 10-K filed March 23, 2006).

10.12 Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on May 26, 2006).

10.13 Form of Employee Stock Option Agreement under the Abraxas 2005 Employee Long-Term Equity Incentive Plan. (Previously filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed August 26, 2006).

10.14 Purchase Agreement dated as of May 25, 2007, by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, Abraxas Operating, LLC and the purchasers named therein. (Filed as Exhibit 10. 2 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.15 Registration Rights Agreement dated as of May 25, 2007, by and among Abraxas Energy Partners, L.P. and the purchasers named therein. (Filed as Exhibit 10. 3 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.16 Omnibus Agreement dated as of May 25, 2007, by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P., Abraxas General Partner, LLC and Abraxas Operating, LLC. (Filed as Exhibit 10. 4 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.17 Second Amended and Restated Agreement of Limited Partnership of Abraxas Energy Partners, L.P. (Filed as Exhibit 10.17 to Abraxas Annual Report on Form 10-K filed on March 17, 2008)

10.18 Securities Purchase Agreement dated May 25, 2007 by and among Abraxas Petroleum Corporation and the purchasers named therein. (Filed as Exhibit 10.7 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.19 Form of Common Stock Purchase Warrant. (Filed as Exhibit 10. 8 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.20 Exchange and Registration Rights Agreement dated as of May 25, 2007 by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P. and the purchasers named therein. (Filed as Exhibit 10. 9 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.21 Credit Agreement dated June 27, 2007 among Abraxas Petroleum Corporation, the lenders party thereto and Société Générale as Administrative Agent and Issuing Lender. (Filed as Exhibit 10.1 to Abraxas Current Report on Form 8-K filed June 28, 2007).

10.22 Amended and Restated Credit Agreement dated January 31, 2008 among Abraxas Energy Partners, L.P., the lenders party thereto, Société Générale as Administrative Agent and Issuing Lender, The Royal Bank of Canada, as Syndication Agent, and The Royal Bank of Scotland PLC, as

Documentation Agent. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed on February 6, 2008).

10.23 Subordinated Credit Agreement dated January 31, 2008 among Abraxas Energy Partners, L.P., the lenders party thereto, Société Générale, as Administrative Agent, and The Royal Bank of Canada, as Syndication Agent. (Filed as Exhibit 10.3 to Abraxas' Current Report on Form 8-K filed on February 6, 2008).

10.24 Intercreditor and Subordination Agreement dated January 31, 2008 among Abraxas Energy Partners, L.P., the Senior Lenders party thereto, the Subordinated Lenders party thereto and Société Générale, as Administrative Agent. (Filed as Exhibit 10.4 to Abraxas' Current Report on Form 8-K filed on February 6, 2008).

10.25 Form of Indemnification Agreement by and among Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, and each of its officers and directors. (Filed as Exhibit 10.25 to Abraxas' Annual Report on Form 10-K filed on March 17, 2008).

10.26 Amendment No. 2 to Registration Rights Agreement dated October 6, 2008, by and among Abraxas Energy Partners, L.P. and the Purchasers. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on October 6, 2008).

10.27 Amendment No. 1 to Exchange and Registration Rights Agreement dated October 6, 2008 by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P. and the Purchasers. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed on October 6, 2008)

10.28 Amendment No. 1 to Amended and Restated Credit Agreement dated January 16, 2009, by and among Abraxas Energy Partners, L.P., Société Générale, as administrative agent and issuing lender, The Royal Bank of Canada, as syndication agent, The Royal Bank of Scotland PLC, as documentation agent, and the lenders signatory thereto. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on January 20, 2009).

10.29 Amendment No. 1 to Subordinated Credit Agreement dated January 16, 2009 by and among Abraxas Energy Partners, L.P., Société Générale, as administrative agent, The Royal Bank of Canada, as syndication agent, and the lenders signatory thereto. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on January 20, 2009).

14.1 Abraxas Petroleum Corporation Code of Business Conduct and Ethics. (Filed as Exhibit 14.1 to Abraxas Annual Report on Form 10-K filed March 22, 2006).

18.1 Change in Accounting Principles. (Filed as Exhibit 18.1 to Abraxas Annual Report on Form 10-K/A Number 2 filed on August 20, 2008)

21.1 Subsidiaries of Abraxas. (Filed as Exhibit 21.1 to Abraxas Annual Report on Form 10-K filed on March 17, 2008)

23.1 Consent of BDO Seidman, LLP. (Filed herewith).

23.2 Consent of DeGoyler 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.

Exhibit Index

23.1	Consent of BDO Seidman, LLP. (Filed herewith).
23.2	Consent of DeGoyler & 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).

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

DATED: February 24, 2009

Pursuant to the requirements of the Securities 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	February 24, 2009
/s/ Chris E. Williford Chris E. Williford	Exec. Vice President and Treasurer (Principal Financial and Accounting Officer)	February 24, 2009
/s/ Craig S. Bartlett, Jr. Craig S. Bartlett, Jr.	Director	February 24, 2009
/s/ Franklin A. Burke Franklin A. Burke	Director	February 24, 2009
/s/ Harold D. Carter Harold D. Carter	Director	February 24, 2009
/s/ Ralph F. Cox Ralph F. Cox	Director	February 24, 2009
/s/ Dennis E. Logue Dennis E. Logue	Director	February 24, 2009
/s/ Paul A. Powell Paul A. Powell	Director	February 24, 2009

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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 as of December 31, 2007 and 2008 and the related consolidated statements of operations, stockholders' equity, cash flows, and other comprehensive income (loss) for each of the three years in the period ended December 31, 2008. 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, 2007 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008**,** in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Abraxas Petroleum Corporation's internal control over financial reporting as of December 31, 2008, 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 February 24, 2009 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Dallas, Texas
February 24, 2009

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

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

We have audited Abraxas Petroleum Corporation's internal control over financial reporting as of December 31, 2008, 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, included in the accompanying Item 9A, "Management's Report on Internal Control Over Financial Reporting". Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Abraxas Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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 of Abraxas Petroleum Corporation as of December 31, 2007 and 2008, and the related consolidated statements of operations, stockholders' equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2008 and our report dated February 24, 2009 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Dallas, Texas
February 24, 2009

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2007	December 31, 2008
	(Dollars in thousands)	
Current assets:		
Cash and cash equivalents	$ 18,936	$ 1,924
Accounts receivable:		
Joint owners	840	1,740
Oil and gas production sales	5,288	6,168
Other	—	58
	6,128	7,966
Derivative asset – Current	2,658	22,832
Other current assets	377	572
Total current assets	28,099	33,294
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	265,090	440,712
Unproved properties excluded from depletion	—	—
Other property and equipment	3,633	10,986
Total	268,723	451,698
Less accumulated depreciation, depletion, and amortization	151,696	291,390
Total property and equipment - net	117,027	160,308
Deferred financing fees, net	856	1,443
Derivative asset – long-term	359	16,394
Other assets including marketable securities	778	400
Total assets	$ 147,119	$ 211,839

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2007	December 31, 2008
	(Dollars in thousands)	
Current liabilities:		
Accounts payable	$ 7,413	$ 10,748
Joint interest oil and gas production payable	2,429	3,176
Accrued interest	241	350
Other accrued expenses	1,514	1,886
Derivative liability – current	5,154	3,000
Current maturities of long-term debt	—	40,134
Total current liabilities	16,751	59,294
Long-term debt – less current maturities	45,900	130,835
Derivative liability – long-term	3,941	—
Future site restoration	1,183	9,959
Total liabilities	67,775	200,088
Minority interest	23,497	7,093
Commitments and contingencies		
Stockholders' equity:		
Convertible preferred stock, par value $.01, authorized 1,000,000 shares; -0- shares issued and outstanding.	—	—
Common stock, par value $.01 per share – authorized 200,000,000 shares; issued 49,020,949 and 49,622,423	490	496
Additional paid-in capital	185,646	187,243
Accumulated deficit	(130,791)	(183,194)
Accumulated other comprehensive income	502	113
Total stockholders' equity	55,847	4,658
Total liabilities, minority interest and stockholders' equity	$ 147,119	$ 211,839

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2006	2007	2008
	(In thousands except per share data)		
Revenues:			
Oil and gas production revenues	$ 49,448	$ 46,906	$ 99,084
Rig revenues	1,613	1,396	1,210
Other	16	7	16
	51,077	48,309	100,310
Operating costs and expenses:			
Lease operating and production taxes	11,776	11,254	26,635
Depreciation, depletion, and amortization	14,939	14,292	23,343
Impairment	—	—	116,366
Rig operations	819	801	856
General and administrative (including stock-based compensation of $998; $996; and $1,404 respectively)	5,160	6,438	7,127
	32,694	32,785	174,327
Operating income (loss)	18,383	15,524	(74,017)
Other (income) expense:			
Interest income	(29)	(408)	(187)
Amortization of deferred financing fees	1,591	671	1,028
Interest expense	16,767	8,392	10,496
Financing fees	—	—	359
Loss (gain) on derivative contracts (unrealized $(81); $6,288 and $(37,860))	(646)	4,363	(28,333)
Loss on debt extinguishment	—	6,455	—
Gain on sale of assets	—	(59,439)	—
Other		347	8,523
	17,683	(39,619)	(8,114)
Income (loss) from operations before income tax and minority interest	700	55,143	(65,903)
Income tax	—	(283)	—
Income (loss) before minority interest	700	54,860	(65,903)
Minority interest in loss of partnership	—	1,842	13,500
Net income (loss)	$ 700	$ 56,702	$ (52,403)
Net income (loss) per common share - basic	$ 0.02	$ 1.22	$ (1.07)
Net income (loss) per common share - diluted	$ 0.02	$ 1.19	$ (1.07)

See accompanying notes to consolidated financial statements

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

	Common Stock		Treasury Stock					
	Shares	Amount	Shares	Amount	Additional Paid-InCapital	Accumulated Deficit	Accumulated Other Comprehensive Income(Loss)	Total
Balance at December 31, 2005	42,063,167	$ 421	56,477	$ (408)	$ 162,795	$ (188,193)	$ 1,684	$ (23,701)
Net Income	—	—	—	—	—	700	—	700
Change in unrealized gain (loss) fair value of investments	—	—	—	—	—	—	(709)	(709)
Stock-based compensation	—	—	—	—	998	—	—	998
Shares issued for compensation	5,782	—	(20,925)	123	14	—	—	137
Stock options exercised	693,517	7	—	—	403	—	—	410
Balance at December 31, 2006	42,762,466	428	35,552	(285)	164,210	(187,493)	975	(22,165)
Net Income	—	—	—	—	—	56,702	—	56,702
Change in unrealized gain (loss) fair value of investments	—	—	—	—	—	—	(473)	(473)
Stock-based compensation	—	—	—	—	996	—	—	996
Shares issued for compensation	22,960	—	(35,552)	285	(94)	—	—	191
Stock options exercised	208,109	2	—	—	10	—	—	12
Equity issuance, net of offering costs	5,874,678	59	—	—	20,525	—	—	20,584
Restricted stock issue	152,736	1	—	—	(1)	—	—	—
Balance at December 31, 2007	49,020,949	490	—	—	185,646	(130,791)	502	55,847
Net Loss						(52,403)		(52,403)
Change in unrealized gain (loss) fair value of investments	—	—	—	—	—	—	(389)	(389)
Stock-based compensation	—	—	—	—	1,162	—	—	1,162
Shares issued for compensation	30,655	—	—	—	60	—	—	60
Stock options exercised	141,501	2	—	—	65	—	—	67
Warrants exercised	31,961	—	—	—	—	—	—	—
Conversion of units in Partnership	344,752	3	—	—	290	—	—	293
Restricted stock issued, net of cancellations	52,605	1	—	—	20	—	—	21
Balance at December 31, 2008	49,622,423	$ 496	—	$ —	$ 187,243	$ (183,194)	$ 113	$ 4,658

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2006	2007	2008
	(In thousands)		
Operating Activities			
Net income (loss)	$ 700	$ 56,702	$ (52,403)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Minority interest in partnership loss	—	(1,842)	(13,500)
(Gain) loss on sale of partnership interest	—	(59,439)	—
Change in derivative fair value	(81)	6,235	(42,304)
Depreciation, depletion, and amortization	14,939	14,292	23,343
Impairment	—	—	116,366
Accretion of future site restoration	133	127	570
Amortization of deferred financing fees	1,591	671	1,028
Stock-based compensation	998	996	1,404
Other non-cash transactions	92	191	7,446
Changes in operating assets and liabilities:			
Accounts receivable	2,357	112	(1,838)
Other assets and liabilities	(486)	15	(206)
Accounts payable	(5,406)	1,063	4,082
Accrued expenses	724	(791)	(601)
Net cash provided by operations	15,561	18,332	43,387
Investing Activities			
Capital expenditures, including purchases and development of properties	(26,346)	(26,908)	(174,586)
Proceeds from the sale of oil and gas properties	12,244	—	642
Net cash used in investing activities	(14,102)	(26,908)	(173,944)
Financing Activities			
Proceeds from issuance of common stock	455	22,441	88
Proceeds from issuance of partnership equity	—	100,000	—
Cost of common stock and partnership equity issuance	—	(9,098)	—
Proceeds from long-term borrowings	20,444	46,690	135,084
Payments on long-term borrowings	(22,357)	(128,404)	(10,015)
Partnership distribution to minority interest	—	(3,163)	(9,997)
Deferred financing fees	—	(997)	(1,615)
Net cash provided by (used in) financing activities	(1,458)	27,469	113,545
Increase (decrease) in cash	1	18,893	(17,012)
Cash at beginning of year	42	43	18,936
Cash at end of year	$ 43	$ 18,936	$ 1,924
Supplemental disclosures of cash flow information:			
Interest paid	$ 12,583	$ 9,494	$ 9,817

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2006	2007	2008
	(In thousands)		
Net income (loss)	$ 700	$56,702	$(52,403)
Other Comprehensive income (loss):			
Change in unrealized value of investments	(709)	(473)	(389)
Other comprehensive loss	(709)	(473)	(389)
Comprehensive income (loss)	$ (9)	$56,229	$(52,792)

See accompanying notes to consolidated financial statements.

1. Organization and Significant Accounting Policies

Nature of Operations

Abraxas Petroleum Corporation ("Abraxas" or "Abraxas Petroleum") is an independent energy company primarily engaged in the exploration of and the acquisition, development, and production of oil and gas principally in Texas, the Mid-Continent and the Rocky Mountains. The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries and its 47.3% interest in Abraxas Energy Partners, L.P. (the "Partnership"). All intercompany accounts and transactions have been eliminated in consolidation.

The terms "Abraxas" and "Abraxas Petroleum" refers only to Abraxas Petroleum Corporation, the term "Partnership" refers only to Abraxas Energy Partners L.P. and the terms "we," "us," "our," or the "Company," refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and the operations of the Partnership which was formed on May 25, 2007. The operations of Abraxas Petroleum and the Partnership are consolidated for financial reporting purposes. The interest of the 52.7% owners of the Partnership is presented as minority interest. Abraxas owns the remaining 47.3% of the partnership interests. The Company has determined that based on its control of the general partner of the Partnership, this 47.3% owned entity should be consolidated for financial reporting purposes. See Note 4 for condensed consolidating financial statements.

Liquidity

The current global recession has had a significant impact on our operations. As a result of the global recession, commodity prices are depressed and may stay depressed or reduce further, thereby causing a prolonged downturn, which could reduce our future cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Additionally the Partnership's Subordinated Credit Agreement matures on July 1, 2009. The Partnership has intended to repay its indebtedness under the Subordinated Credit Agreement with proceeds from its initial public offering. However, the equity capital markets have been negatively affected in recent months. As a result, we cannot assure you that the Partnership will be successful in completing the IPO prior to the maturity of the Subordinated Credit Agreement. Abraxas Energy is currently in discussions with Société Générale to amend the existing Senior Secured Credit Facility and/or the Subordinated Credit Agreement in the event the IPO is not completed by April 30, 2009. The Partnership has also entered into discussions with other lending institutions to re-finance the $40 million currently outstanding on the Subordinated Credit Agreement. While the Company believes that there are options to this short term maturity requirement, there are no guarantees that any of these options will be successfully implemented.

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 future proved oil and 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 oil and gas price derivative contracts. 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 counterparty to the Partnership's oil and gas price contracts is the same financial institution from which the Partnership has outstanding debt, accordingly the Company believes its exposure to credit risk to this counterparty is currently mitigated in part by this, as well as the current overall financial condition of the counterparty.

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 include 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 $10,000 and $33,000 at December 31, 2007 and 2008, 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.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and 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 oil and 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 oil and 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. The Company does not have any properties that are being excluded from amortization. Costs in excess of the present value of estimated future net revenues as discussed above are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties, except in unusual circumstances. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. During the fourth quarter the Company incurred approved property impairment due to the decrease in commodity prices during the period. For the year ended December 31, 2008, the Company incurred an impairment of $116.4 million, based on year end prices of $44.60 per barrel of oil and $5.62 per Mcf of gas.

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.

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with U.S. generally accepted accounting principles ("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.

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. Future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate which would impact the estimated value of our reserves.

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.

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are primarily in the form of fixed price swaps, which limit the impact of price fluctuations with respect to the Company's sale of oil and gas. The Company does not enter into speculative hedges.

Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. The Company elected out of hedge accounting as prescribed by SFAS 133. Accordingly, all derivatives are recorded on the balance sheet at fair value with changes in fair value being recognized in earnings.

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 carrying value. The Company assumes the carrying 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.

Share-Based Payments

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the years ended December 31, 2006, 2007 and 2008, stock based compensation was approximately $998,000; $996,000 and $1.4 million respectively. For additional information regarding share-based payments please see Note 6 "Stock-based Compensation, Option Plans and Warrants."

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.

FASB Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (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 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 estimated 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 during the following years ended December 31:

	2006	2007	2008
	(in thousands)		
Beginning asset retirement obligation	$ 883	$ 1,019	$ 1,183
New wells placed on production and other	29	43	9,046
Deletions related to property disposals	(26)	(6)	(840)
Accretion expense	133	127	570
Ending asset retirement obligation	$ 1,019	$ 1,183	$ 9,959

Revenue Recognition and Major Purchasers

The Company recognizes oil and gas revenue from its interest in producing wells as oil and gas is sold from those wells, net of royalties. 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, 2007 and 2008.

Rig revenue is recognized as workover rig services are performed on our wells on behalf of third party working interest owners.

During 2006, 2007 and 2008 two purchasers accounted for 25% and, 24%; 25% and 23%; and 14% and 15% of oil and gas revenues, respectively.

Deferred Financing Fees

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

Income Taxes

The Company records deferred income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

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. Comprehensive income for the Company is the change in the market value of marketable securities.

Accounting for Uncertainty in Income Taxes

In June 2006 the Financial Accounting Standards Board issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109 (FIN 48), FIN 48 is intended to clarify the accounting for uncertainty in income taxes recognized in a company's financial statements and prescribes the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Under FIN 48, evaluation of a tax position is a two-step process. The first step is to determine whether it is more-likely- than- not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation based on the technical merits of that position. The second step is to measure a tax position that meets the more-likely-than-not threshold to determine the amount of benefit to be recognized in the financial statements. A tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent period in which the threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not criteria should be de-recognized in the first subsequent reporting period in which the threshold is no longer met.

The adoption of FIN 48 at January 1, 2008 did not have an impact on the Company's financial position.

New Accounting Pronouncements

Fair Value Measurements (SFAS No. 157) — In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The FASB agreed to defer the effective date of Statement 157 for one year for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. There is no deferral for financial assets and financial liabilities. See Note 15 for further details of the impact of this statement on the consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a "business" and a "business combination" have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. We cannot predict the impact that the adoption of SFAS No. 141(R) will have on our financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2008.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in the equity in the consolidated financial statements separately from the parent's equity. Subsequent changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest, are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. Due to our investment in Abraxas Energy Partners, the adoption of SFAS No. 160 could have a material impact on our financial position and results of operations, however we do not believe that it will have a material impact on our cash flows. Under current accounting rules, when cumulative losses applicable to the minority interest exceed the minority interest equity capital in the entity, such excess and any further losses applicable to the minority interest are charged to the earnings of the majority interest. For the year ended December 31, 2008, Abraxas included a loss of $9.3 million relating to the Partnerships loss in excess of the minority interest equity. Under SFAS No. 160 the loss in excess of capital would be a component of consolidated equity and would not be included in the earnings of the majority interest.

The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115 (SFAS No. 159) — In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement is effective for fiscal years beginning after November 15, 2007. We have not elected the fair value treatment afforded by SFAS No. 159.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Enhanced disclosures to improve financial reporting transparency are required and include disclosure about the location and amounts of derivative instruments in the financial statements, how derivative instruments are accounted for and how derivatives affect an entity's financial position, financial performance and cash flows. A tabular format including the fair value of derivative instruments and their gains and losses, disclosure about credit risk-related derivative features and cross-referencing within the footnotes are also new requirements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application and comparative disclosures encouraged, but not required. We have not yet adopted SFAS No. 161. We do not believe that SFAS No. 161 will have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles." The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are prepared in conformance with generally accepted accounting principles. Unlike Statement on Auditing Standards (SAS) No. 69, "The Meaning of Present in Conformity With GAAP," FAS No. 162 is directed to the entity rather than the auditor. The statement is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board (PCAOB) amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with GAAP," and is not expected to have any impact on the Company's results of operations, financial condition or liquidity.

On December 29, 2008, the Securities and Exchange Commission adopted rule changes to modernize its oil and gas reporting disclosures. The changes are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves.

The updated disclosure requirements are designed to align with current practices and changes in technology that have taken place in the oil and gas industry since the adoption of the original reporting requirements more than 25 years ago.

New disclosure requirements include:

- Permitting the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes.
- Enabling companies to additionally disclose their probable and possible reserves to investors. Currently, the rules limit disclosure to only proved reserves.
- Allowing previously excluded resources, such as oil sands, to be classified as oil and gas reserves.
- Requiring companies to report on the independence and qualifications of a preparer or auditor and requiring companies to file reports when a third party is relied upon to prepare reserve estimates or conduct a reserves audit.
- Requiring companies to report oil and gas reserves using an average price based upon the prior 12-month period – rather than the year-end price – to maximize the comparability of reserve estimates among companies and mitigate the distortion of the estimates that arises when using a single pricing date.

The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending on or after December 31, 2009. The Company believes that this new requirement could have a significant impact on reported reserves and depletion rates when implemented.

Segment and Related Information

Although we have a number of operating divisions, separate segment data has not been presented as they meet the criteria for aggregation as permitted by SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information."

2. Partnership Formation

On May 25, 2007, Abraxas Petroleum Corporation entered into a contribution, conveyance and assumption agreement with the Partnership, Abraxas General Partner, LLC, a Delaware limited liability company and wholly-owned subsidiary of Abraxas which we refer to as the GP, Abraxas Energy Investments, LLC, a Texas limited liability company and wholly-owned subsidiary of Abraxas which we refer to as the LP, and Abraxas Operating, LLC, a Texas limited liability company and wholly-owned subsidiary of Abraxas Energy Partners which we refer to as the Operating Company. Among other things, the contribution agreement provided for the contribution by Abraxas to the Operating Company of certain assets located in South and West Texas in exchange for all of the equity interests of the Operating Company.

In consideration for these assets, the Partnership and the Operating Company, jointly and severally, assumed all of Abraxas' existing indebtedness under its Floating Rate Senior Secured Notes due 2009, which we refer to as the notes, and the obligation to pay certain preformation and transaction expenses and issued general partner units and common units to the GP and the LP, respectively, in exchange for their ownership interests in the Operating Company. On May 25, 2007, Abraxas Energy Partners sold 6,002,408 common units, representing an approximate 52.8% interest in Abraxas Energy Partners, for $16.66 per Common Unit, or approximately $100 million, pursuant to a purchase agreement dated May 25, 2007, to a group of accredited investors. After consummation of these transactions, the general partner units and the common units owned by the GP and the LP constituted a 47.2% ownership interest in the Partnership.

As a result of these transactions, the Company recognized a gain of $59.4 million in 2007. The gain was calculated in accordance with the requirements of SEC Staff Accounting Bulletin 51, (Topic 5H) based on the fact that the Company elected gain treatment as a policy and the transaction met the following criteria: (1) there were no additional broad corporate reorganizations contemplated; (2) there was not a reason to believe that the gain would not be realized, since there is no additional capital raising transaction anticipated nor was there a significant concern about the new entity's ability to continue in existence; (3) the share price of capital raised in the private placement was objectively determined; (4) no repurchases of the new subsidiary's units are planned; and (5) the Company acknowledges that it will consistently apply the policy, and any future transactions that might result in a loss must be recorded as a loss in the statement of operations.

3. Registration and Exchange Rights Agreements

Registration Rights Agreement. On May 25, 2007, in connection with Abraxas Energy's private placement offering, the Partnership entered into a registration rights agreement with the private investors, which was amended on December 5, 2007 and on October 6, 2008. Under the registration rights agreement, the Partnership agreed as soon as practicable, (a) to prepare and file with the SEC a registration statement for (1) an initial public offering of common units and (2) a shelf registration statement for the resale of the common units held by the private investors and (b) to use commercially reasonable efforts to cause the IPO registration statement and the shelf registration statement to be declared effective by April 30, 2009.

The registration rights agreement required the Partnership to pay liquidated damages if the IPO registration statement or the shelf registration statement is not declared effective by April 30, 2009. The liquidated damages equate to \$0.04165 per common unit for the first 60 days after April 30, 2009, with such amount increasing by an additional \$0.04165 per common unit for each 30-day period for the next 60 days up to a maximum of \$0.1666 per common unit. Liquidated damages are payable in cash, unless the Partnership is unable to as a result of a restriction under its credit facility, in which case, the liquidated damages will be paid in-kind. As the Company currently believes that it is not probable that amounts will be payable under this provision, no liability has been recorded for this contingency as of December 31, 2008.

Exchange and Registration Rights Agreement. Abraxas Energy, Abraxas Petroleum and the private investors entered into an exchange and registration rights agreement dated May 25, 2007, and amended on October 6, 2008. Under the terms of the amended agreement, in the event that the Partnership has not consummated its initial public offering by April 30, 2009 ("the Trigger Date"), the private investors have the right to convert their common units purchased in the private placement offering into shares of common stock of Abraxas Petroleum. Each of the Partnership's common units are convertible into a number of shares of Abraxas Petroleum common stock equal to \$16.66 divided by the then current market price of Abraxas Petroleum's common stock times 0.9. Abraxas Petroleum also agreed within 30 days of the Trigger Date, to prepare and file with the SEC a registration statement to enable the resale of ABP common stock. Abraxas Petroleum further agreed to use its commercially reasonable efforts to cause the registration statement to become effective by the 120th calendar day following the Trigger Date. In consideration of the October 2008 amendment, Abraxas Energy agreed to pay the private investors \$0.0625 per unit per quarter beginning with the fourth quarter of 2008 and ending on certain events, including the initial public offering. This payment is payable in cash, unless the Partnership is unable to as a result of a restriction under its credit facility, in which case, the payment will be paid in-kind. In the fourth quarter of 2008, in connection with conversion rights held by the original investors in the Partnership, approximately 343,000 shares of Common stock were issued upon conversion of partnership units.

Terms of the exchange and registration rights agreement are such that there is a maximum number of shares of Abraxas Common Stock, representing approximately 20% of the total number of common shares outstanding, into which the holders of the Partnership units may convert without further action on the part of Abraxas shareholders. As a result of this, the minority interest reflected in the Company's balance sheet represents the value of these potential shares into which the Partnership units may be converted. Losses at the Partnership in excess of this amount (approximately \$7.1 million) have not been allocated to the minority interest and, instead have been absorbed by the Company. To the extent that the Partnership operates profitably in the future, such profits will be first allocated back to the Company to the extent of any excess losses previously recorded, prior to the allocation of such profits to the minority interest.

4. Condensed Consolidating Financial Statements

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and the operations of the Partnership which was formed on May 25, 2007. The operations of Abraxas Petroleum and the Partnership are consolidated for financial reporting purposes. The interest of the 52.7% owners of the Partnership presented as minority interest. Abraxas owns the remaining 47.3% of the partnership interests. The Company has determined that based on its control of the general partner of the Partnership, this 47.3% owned entity should be consolidated for financial reporting purposes. The consolidating financial statements are presented as follows:

Condensed Consolidating Balance Sheet
December 31, 2008
(In thousands)

	Abraxas Petroleum Corporation	Abraxas Energy Partners, L.P.	Reclassifications and eliminations	Consolidated
Assets:				
Cash	$ —	$ 1,924	$ —	$ 1,924
Accounts receivable, less allowance for doubtful accounts	11,514	7,695	(11,243)	7,966
Derivative asset – current	—	22,832	—	22,832
Other current assets	535	37	—	572
Total current assets	12,049	32,488	(11,243)	33,294
Property and equipment – net	41,291	119,017	—	160,308
Deferred financing fees, net	102	1,341	—	1,443
Derivative asset – long-term	—	16,394	—	16,394
Investment in partnership	11,889	—	(11,889)	—
Other assets	400	—	—	400
Total assets	$ 65,731	$ 169,240	$ (23,132)	$ 211,839
Liabilities and Stockholders' deficit:				
Current liabilities:				
Accounts payable	$ 21,659	$ 1,150	$ (8,885)	$ 13,924
Accrued interest	18	332	—	350
Other accrued expenses	1,643	243	—	1,886
Derivative liability – current	—	3,000	—	3,000
Current maturities of long-term debt	134	40,000	—	40,134
Dividend payable	—	2,358	(2,358)	—
Total current liabilities	23,454	47,083	(11,243)	59,294
Long-term debt	5,235	125,600	—	130,835
Future site restoration	910	9,049	—	9,959
Total liabilities	29,599	181,732	(11,243)	200,088
Minority interest	—		7,093	7,093
Partnership capital	—	34,324	(34,324)	—
Stockholders'/Partners equity (deficit)	36,132	(46,816)	15,342	4,658
Total liabilities and stockholders' equity (deficit)	$ 65,731	$ 169,240	$ (23,132)	$ 211,839

Condensed Consolidating Balance Sheet
December 31, 2007
(In thousands)

	Abraxas Petroleum Corporation	Abraxas Energy Partners, L.P.	Reclassifi-cations and eliminations	Consolidated
Assets:				
Cash	$ 17,177	$ 1,759	$ —	$ 18,936
Accounts receivable, less allowance for doubtful accounts	6,288	4,696	(4,856)	6,128
Derivative asset – current	—	2,658	—	2,658
Other current assets	355	22	—	377
Total current assets	23,820	9,135	(4,856)	28,099
Property and equipment – net	21,533	95,494	—	117,027
Deferred financing fees, net	141	715	—	856
Derivative asset – long-term	—	359	—	359
Investment in partnership	27,838	—	(27,838)	—
Other assets	778	—	—	778
Total assets	$ 74,110	$ 105,703	$ (32,694)	$ 147,119
Liabilities and Stockholders' deficit:				
Current liabilities:				
Accounts payable	$ 14,698	$ —	$ (4,856)	$ 9,842
Accrued interest	—	241	—	241
Other accrued expenses	1,514	—	—	1,514
Derivative liability – current	—	5,154	—	5,154
Total current liabilities	16,212	5,395	(4,856)	16,751
Long-term debt	—	45,900	—	45,900
Derivative liability – long-term	—	3,941	—	3,941
Future site restoration	404	779	—	1,183
Total liabilities	16,616	56,015	(4,856)	67,775
Minority interest	—		23,497	23,497
Partnership capital	—	57,438	(57,438)	—
Stockholders'/Partners equity (deficit)	57,494	(7,750)	6,103	55,847
Total liabilities and stockholders' equity (deficit)	$ 74,110	$ 105,703	$ (32,694)	$ 147,119

Condensed Consolidating Parent Company and Subsidiary Statement of Operations
For the year ended December 31, 2008
(In thousands)

	Abraxas Petroleum Corporation	Abraxas Energy Partners, L.P.	Reclassifi-cations and eliminations	Consolidated
Revenues:				
Oil and gas production revenues	$ 15,693	$ 83,391	$ —	$ 99,084
Rig revenues	1,210	—	—	1,210
Other	16	—	—	16
	16,919	83,391	—	100,310
Operating costs and expenses:				
Lease operating and production taxes	4,058	22,577	—	26,635
Depreciation, depletion, and amortization	3,380	20,063	(100)	23,343
Impairment	19,145	97,121	100	116,366
Rig operations	856	—	—	856
General and administrative	4,470	2,657	—	7,127
	31,909	142,418	—	174,327
Operating income (loss)	(14,990)	(59,027)	—	(74,017)
Other (income) expense:				
Interest income	(165)	(22)	—	(187)
Amortization of deferred financing fees	40	988	—	1,028
Interest expense	293	10,203	—	10,496
Financing fees	—	359	—	359
Loss (gain) on derivative contracts	—	(28,333)	—	(28,333)
Other	7,418	1,105	—	8,523
	7,586	(15,700)	—	(8,114)
Income (loss) from operations before income tax and minority interest	(22,576)	(43,327)	—	(65,903)
Income tax	—	—	—	—
Income from operations before minority interest	(22,576)	(43,327)	—	(65,903)
Minority interest	—	—	13,500	13,500
Net income (loss)	$ (22,576)	$ (43,327)	$ 13,500	$ (52,403)

Condensed Consolidating Parent Company and Subsidiary Statement of Operations
For the year ended December 31, 2007
(In thousands)

	Abraxas Petroleum Corporation	Abraxas Energy Partners, L.P. (1)	Reclassifi-cations and eliminations	Consolidated
Revenues:				
Oil and gas production revenues	$ 24,758	$ 22,148	$ —	$ 46,906
Rig revenues	1,396	—	—	1,396
Other	7	—	—	7
	26,161	22,148	—	48,309
Operating costs and expenses:				
Lease operating and production taxes	6,118	5,136	—	11,254
Depreciation, depletion, and amortization	7,253	7,039	—	14,292
Rig operations	801	—	—	801
General and administrative	5,451	987	—	6,438
	19,623	13,162	—	32,785
Operating income (loss)	6,538	8,986	—	15,524
Other (income) expense:				
Interest income	(387)	(21)	—	(408)
Amortization of deferred financing fees	550	121	—	671
Interest expense	6,597	1,795	—	8,392
Loss (gain) on derivative contracts	238	4,125	—	4,363
Loss on debt extinguishment	—	6,455	—	6,455
Gain on sale of assets	(59,439)	—	—	(59,439)
Other	347	—	—	347
	(52,094)	12,475	—	(39,619)
Income (loss) from operations before income tax and minority interest	58,632	(3,489)	—	55,143
Income tax	(283)	—	—	(283)
Income from operations before minority interest	58,349	(3,489)	—	54,860
Minority interest	—	—	1,842	1,842
Net income (loss)	$ 58,349	$ (3,489)	$ 1,842	$ 56,702

(1) From inception, May 25 through December 31.

Condensed Consolidating Parent Company and Subsidiary Statement of Cash Flows
For the year ended December 31, 2008
(In thousands)

	Abraxas Petroleum Corporation	Abraxas Energy Partners, L.P. (1)	Reclassifi-cations and eliminations	Consolidated
Operating Activities				
Net income (loss)	$ (22,576)	$ (43,327)	$ 13,500	$ (52,403)
Adjustments to reconcile net income to net cash provided by operating activities:				
Minority interest in partnership loss	—	—	(13,500)	(13,500)
Change in derivative fair value	—	(42,304)	—	(42,304)
Depreciation, depletion, and amortization	3,380	20,063	(100)	23,343
Proved property impairment	19,145	97,121	100	116,366
Accretion of future site restoration	63	507	—	570
Amortization of deferred financing fees	40	988	—	1,028
Stock-based compensation	1,162	242	—	1,404
Other non-cash transactions	7,446	—	—	7,446
Changes in operating assets and liabilities	6,397	(4,960)	—	1,437
Net cash provided by operations	15,057	28,330	—	43,387
Investing Activities				
Capital expenditures, including purchases and development of properties – net of dispositions	(42,044)	(131,900)	—	(173,944)
Net cash used in investing activities	(42,044)	(131,900)	—	(173,944)
Financing Activities				
Proceeds from issuance of common stock	88	—	—	88
Proceeds from long-term borrowings	5,384	129,700	—	135,084
Payments on long-term borrowings	(15)	(10,000)	—	(10,015)
Partnership distribution	4,354	(14,351)	—	(9,997)
Deferred financing fees	(1)	(1,614)	—	(1,615)
Net cash provided by (used in) financing activities	9,810	103,735	—	113,545
Increase (decrease) in cash	(17,177)	165	—	(17,012)
Cash at beginning of year	17,177	1,759	—	18,936
Cash at end of year	$	$ 1,924	$ —	$ 1,924

Condensed Consolidating Parent Company and Subsidiary Statement of Cash Flows
For the year ended December 31, 2007
(In thousands)

	Abraxas Petroleum Corporation	Abraxas Energy Partners, L.P. (1)	Reclassifi-cations and eliminations	Consolidated
Operating Activities				
Net income (loss)	$ 58,349	$ (3,489)	$ 1,842	$ 56,702
Adjustments to reconcile net income to net cash provided by operating activities:				
Minority interest in partnership loss	—	—	(1,842)	(1,842)
(Gain) loss on sale of partnership interest	(59,439)	—	—	(59,439)
Change in derivative fair value	157	6,078	—	6,235
Depreciation, depletion, and amortization	7,253	7,039	—	14,292
Accretion of future site restoration	(18)	145	—	127
Amortization of deferred financing fees	550	121	—	671
Stock-based compensation	996	—	—	996
Other non-cash transactions	191	—	—	191
Changes in operating assets and liabilities	4,827	(4,428)	—	399
Net cash provided by operations	12,866	5,466	—	18,332
Investing Activities				
Capital expenditures, including purchases and development of properties	(12,822)	(14,086)	—	(26,908)
Net cash used in investing activities	(12,822)	(14,086)	—	(26,908)
Financing Activities				
Proceeds from issuance of common stock	22,441	—	—	22,441
Proceeds from issuance of partnership equity - (net)	(6,305)	97,207	—	90,902
Proceeds from long-term borrowings	790	45,900	—	46,690
Payments on long-term borrowings	(2,500)	(125,904)	—	(128,404)
Partnership distribution	2,825	(5,988)	—	(3,163)
Deferred financing fees	(161)	(836)	—	(997)
Net cash provided by (used in) financing activities	17,090	10,379	—	27,469
Increase (decrease) in cash	17,134	1,759	—	18,893
Cash at beginning of year	43	—	—	43
Cash at end of year	$ 17,177	$ 1,759	$ —	$ 18,936

5. Acquisitions

On January 31, 2008, Abraxas Operating, LLC, a wholly-owned subsidiary of the Partnership, consummated the acquisition of certain oil and gas properties located in various states from St. Mary Land & Exploration Company (“St. Mary”) and certain other sellers. The properties are primarily located in the Rockies and Mid-Continent regions of the United States, and include approximately 57.2 Bcfe (9,525 MBOE) of estimated proved reserves for a purchase price of approximately $126.0 million.

The Partnership borrowed approximately $115.6 million under the Partnership Credit Facility and $50 million under its Subordinated Credit Agreement in order to complete this acquisition and repay its previously outstanding indebtedness of $45.9 million. For a complete description of these credit facilities, please see Note 6 “Long-Term Debt”.

Simultaneously, Abraxas Petroleum announced that it had completed the acquisition of certain oil and gas properties from St. Mary with estimated proved reserves of approximately 4.3 Bcfe (725 MBOE) for a purchase price of approximately $5.6 million. Abraxas paid the purchase price from its internal funds. The right to purchase these properties had been assigned to Abraxas by the Partnership.

Substantially all amounts paid in the acquisition, including acquisition costs of approximately $1.1 million, were allocated to the oil and gas properties. The following unaudited supplemental information presents pro forma financial results assuming the acquisition had occurred on January 1 of 2008 and 2007. The unaudited pro forma financial results are not necessarily those that would have been attained had the acquisition occurred as of an earlier date, nor are they necessarily representative of the future results that may occur.

Unaudited Pro Forma Financial Information

		Year ended December 31,	
		2007	2008
	Revenue	$ 87,643	$ 104,262
6.	Net income (loss)	$ 58,242	$ (50,281)
	Earnings (loss) per share – basic	$ 1.26	$ (1.02)

Long-Term Debt

The following is a description of the Company's debt as of December 31, 2007 and 2008, respectively:

	December 31, 2007	**December 31, 2008**
Partnership credit facility	45,900	125,600
Subordinated Partnership credit agreement	—	40,000
Senior secured credit facility	—	—
Real estate lien note	—	5,369
	45,900	170,969
Less current maturities	—	(40,134)
	$ 45,900	$ 130,835

Maturities of long-term debt are as follows:

Year ended December 31,	
2009	$ 40,134
2010	143
2011	152
2012	163
2013	125,773
Thereafter	4,604
	$ 170,969

Abraxas Senior Secured Credit Facility. On June 27, 2007, Abraxas entered into a new senior secured revolving credit facility, which we refer to as the Credit Facility. The Credit Facility has a maximum commitment of $50 million. Availability under the Credit Facility is subject to a borrowing base. The borrowing base under the Credit Facility, which is currently $6.5 million, is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, may make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we may also request one redetermination during any six-month period between scheduled redeterminations. The lenders may also make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our current borrowing base. Our borrowing base at December 31, 2008 of $6.5 million was determined based upon our reserves at June 30, 2008. Our borrowing base can never exceed the $50.0 million maximum commitment amount. Outstanding amounts under the Credit Facility will bear interest at (a) the greater of the reference rate announced from time to time by Société Générale, and (b) the Federal Funds Rate plus 0.5% of 1%, plus in each case, (c) 0.5% - 1.5% depending on utilization of the borrowing base, or, if Abraxas elects, at the London Interbank Offered Rate plus 1.5% - 2.5%, depending on the utilization of the borrowing base. Subject to earlier termination rights and events of default, the Credit Facility's stated maturity date is June 27, 2011. Interest will be payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances.

Abraxas is permitted to terminate the Credit Facility, and may, from time to time, permanently reduce the lenders' aggregate commitment under the Credit Facility in compliance with certain notice and dollar increment requirements.

Each of Abraxas' subsidiaries other than the Partnership, Abraxas General Partner, LLC and Abraxas Energy Investments, LLC has guaranteed Abraxas' obligations under the Credit Facility on a senior secured basis. Obligations under the Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of Abraxas' and the subsidiary guarantors' material property and assets.

Under the Credit Facility, Abraxas is subject to customary covenants, including certain financial covenants and reporting requirements. The Credit Facility requires Abraxas to maintain a minimum Current Ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio (generally defined as the ratio of consolidated EBITDA to consolidated interest expense as of the last day of such quarter) of not less than 2.50 to 1.00.

In addition to the foregoing and other customary covenants, the Credit Facility contains a number of covenants that, among other things, will restrict Abraxas' ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an "arms-length" basis;
- make any change in the principal nature of its business; and
- permit a change of control.

The 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.

The Company is in compliance with all covenants as of December 31, 2008.

Amended and Restated Partnership Credit Facility. On May 25, 2007, the Partnership entered into a senior secured revolving credit facility which was amended and restated on January 31, 2008 and further amended on January 16, 2009, which we refer to as the Partnership Credit Facility. The Partnership Credit Facility has a maximum commitment of $300.0 million. Availability under the Partnership Credit Facility is subject to a borrowing base. The borrowing base under the Partnership Credit Facility, which is currently $140.0 million, is determined semi-annually by the lenders based upon the Partnership's reserve reports, one of which must be prepared by the Partnership's independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of the Partnership's proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, may make one additional borrowing base redetermination during any six-month period between scheduled redeterminations. The lenders may also make a redetermination in connection with any sales of producing properties with a market value of 5% or more of the Partnership's current borrowing base. The

Partnership's current borrowing base of $140.0 million was determined based upon its reserves at June 30, 2008. The borrowing base can never exceed the $300.0 million maximum commitment amount. During the period beginning on January 16, 2009 and ending on the date that the Subordinated Credit Agreement is terminated, outstanding amounts under the Partnership Credit Facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR rate plus, in each case, (b) 1.5% - 2.5%, depending on the utilization of the borrowing base, or, if the Partnership elects, at the London Interbank Offered Rate plus 2.5% - 3.5% depending on the utilization of the borrowing base. After the termination of the Subordinated Credit Agreement, outstanding amounts under the Partnership Credit Facility will bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR rate plus, in each case, (b) 1.0% - 2.0%, depending on the utilization of the borrowing base, or, if the Partnership elects, at the London Interbank Offered Rate plus 2.0% - 3.0% depending on the utilization of the borrowing base. At January 16, 2009, the interest rate on the Partnership Credit Facility was 3.8%. Subject to earlier termination rights and events of default, the Partnership Credit Facility's stated maturity date is January 31, 2013. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. The Partnership is permitted to terminate the Partnership Credit Facility, and under certain circumstances, may be required, from time to time, to permanently reduce the lenders' aggregate commitment under the Partnership Credit Facility.

Each of the general partner of the Partnership, Abraxas General Partner, LLC, which is a wholly-owned subsidiary of Abraxas and which we refer to as the GP, and Abraxas Operating, LLC, which is a wholly-owned subsidiary of the Partnership and which we refer to as the Operating Company, has guaranteed the Partnership's obligations under the Partnership Credit Facility on a senior secured basis. Obligations under the Partnership Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the property and assets of the GP, the Partnership and the Operating Company, other than the GP's general partner units in the Partnership.

Under the Partnership Credit Facility, the Partnership is subject to customary covenants, including certain financial covenants and reporting requirements. The Partnership Credit Facility requires the Partnership to maintain a minimum Current Ratio as of the last day of each quarter of 1.00 to 1.00 and an interest coverage ratio (defined as the ratio of consolidated EBITDA to consolidated interest expense) as of the last day of each quarter of not less than 2.50 to 1.00. The Partnership Credit Facility required it to enter into derivative contracts for specific volumes, which equated to approximately 85% of the estimated oil and gas production from its net proved developed producing reserves through December 31, 2011. The Partnership entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011.

Under the terms of the Partnership Credit Facility, the Partnership may make cash distributions if, after giving effect to such distributions, the Partnership is not in default under the Partnership Credit Facility, there is no borrowing base deficiency and provided that (a) no such distribution shall be made using the proceeds of any advance unless the unused portion of the amount then available under the Partnership Credit Facility is greater than or equal to 10% of the lesser of the Partnership's borrowing base (which at January 16, 2009 was $140.0 million) or the total commitment amount of the Partnership Credit Facility (which at January 16, 2009 was currently $300.0 million) at such time, (b) with respect to the cash distribution scheduled to be made on or about May 15, 2009 attributable to the first quarter of 2009, no such distribution shall be made unless (i) the sum of unrestricted cash and the unused portion of the amount then available under the Partnership Credit Facility after giving effect to such distribution exceeds $20.0 million, or (ii) the Subordinated Credit Agreement shall have terminated and (c) no cash distribution shall exceed $0.44 per unit per quarter while the Subordinated Credit Agreement is outstanding. Additionally, while the Subordinated Credit Agreement is outstanding, the Partnership's capital expenditures are limited to $12.5 million.

In addition to the foregoing and other customary covenants, the Partnership Credit Facility contains a number of covenants that, among other things, will restrict the Partnership's ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;

- engage in transactions with affiliates;
- make any change in the principal nature of its business; and
- permit a change of control.

The Partnership 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 including the Subordinated Credit Agreement described below, bankruptcy and material judgments and liabilities.

The Partnership is in compliance with all covenants as of December 31, 2008.

Subordinated Credit Agreement

On January 31, 2008, the Partnership entered into a subordinated credit agreement which was amended on January 16, 2009, which we refer to as the Subordinated Credit Agreement. The Subordinated Credit Agreement has a maximum commitment of $40.0 million. Outstanding amounts under the Subordinated Credit Agreement bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5% and (3) a rate determined by Société Générale as the daily one-month LIBOR Offered Rate, plus in each case (b) 7.50% or, if the Partnership elects, at the greater of (a) 2.0% and (b) at the London Interbank Offered Rate, in each case, plus 8.50%. At January 16, 2009 the interest rate on the Subordinated Credit Agreement was 10.5%. Principal payments under the Subordinated Credit Agreement must be made on May 14, 2009 in an amount, which we refer to as the May 14, 2009 Payment Amount, equal to the lesser of the amount of cash distributed to Abraxas Energy Investments, LLC, a wholly-owned subsidiary of Abraxas Petroleum, on or about February 14, 2009 and $2.25 million with the balance due on the maturity date. The maturity date may be accelerated if any limited partner of the Partnership, other than Perlman Value Partners, exercises its right to convert its limited partner units into shares of common stock of Abraxas Petroleum pursuant to the terms of the Exchange and Registration Rights Agreement dated May 25, 2007, as amended, among Abraxas Petroleum, the Partnership and the purchasers named therein. As a result of the amendment to the Subordinated Credit Agreement, the date on which the purchasers, if the Partnership's initial public offering has not been consummated prior to that date, may first exchange their Partnership units for Abraxas Petroleum common stock is April 30, 2009. Subject to earlier termination rights and events of default, the Subordinated Credit Agreement's stated maturity date is July 1, 2009. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. The Partnership is permitted to terminate the Subordinated Credit Agreement, and under certain circumstances, may be required, from time to time, to make prepayments under the Subordinated Credit Agreement.

Each of the GP and the Operating Company has guaranteed the Partnership's obligations under the Subordinated Credit Agreement on a subordinated secured basis. Obligations under the Subordinated Credit Agreement are secured by subordinated security interests, subject to certain permitted encumbrances, in all of the property and assets of the Partnership, GP, and the Operating Company, other than the GP's general partner units in the Partnership.

Under the Subordinated Credit Agreement, the Partnership is subject to customary covenants, including certain financial covenants and reporting requirements. The Subordinated Credit Agreement requires the Partnership to maintain a minimum current ratio as of the last day of each quarter of 1.00 to 1.00 and an interest coverage ratio (defined as the ratio of consolidated EBITDA to consolidated interest expense) as of the last day of each quarter of not less than 2.50 to 1.00. The Partnership Credit Facility required it to enter into derivative contracts for specific volumes, which equated to approximately 85% of the estimated oil and gas production from its net proved developed producing reserves through December 31, 2011. The Partnership entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011.

In addition to the foregoing and other customary covenants, the Subordinated Credit Agreement contains a number of covenants that, among other things, will restrict the Partnership's ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;

- engage in transactions with affiliates;
- make any change in the principal nature of its business; and
- permit a change of control.

The Subordinated Credit Agreement 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 the Partnership Credit Facility, bankruptcy and material judgments and liabilities. In addition, as a result of the amendment to the Subordinated Credit Agreement, two events of default were added to the Subordinated Credit Agreement. The first event of default would occur if the Partnership fails to receive a letter of credit, which we refer to as the APC L/C, in its favor from Abraxas Petroleum equal to the May 14, 2009 Payment Amount, the Partnership fails to draw on the APC L/C on or before May 14, 2009 or the Partnership fails to use the proceeds of the APC L/C to make the principal payment due on May 14, 2009. This event of default would not occur in the event that the Partnership repays the principal amount due on May 14, 2009 with funds received from Abraxas Petroleum. The Partnership and Abraxas Petroleum have agreed that upon the occurrence of such a payment or the Partnership's drawing on the APC L/C that, in consideration thereof, the Partnership would issue a number of additional units to Abraxas Petroleum determined by dividing the May 14, 2009 Payment Amount by 110% of the average trading yields of comparable E&P MLPs based on the closing market price on May 14, 2009 multiplied by the most recent quarterly distribution paid or declared by the Partnership times four. The other event of default would occur if the Partnership fails to receive $20.0 million of proceeds from an equity issuance on or before April 30, 2009.

The Partnership is in compliance with all covenants as of December 31, 2008.

Real Estate Lien Note

On May 9, 2008 the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a new building to serve as its corporate headquarters. This note was refinanced in November 2008. The new note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2008, $5.4 million was outstanding on the note.

7. Property and Equipment

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

	Estimated Useful Life	December 31, 2007	December 31, 2008
	Years	(In thousands)	
Oil and gas properties	—	$ 265,090	$ 440,712
Equipment and other	3-39	3,633	10,986
		$ 268,723	$ 451,698

8. Stock-based Compensation, Option Plans and Warrants

Stock-based Compensation

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees. 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 2006, 2007 and 2008, risk-free interest rates of 4.62% in 2006, 4.63% in 2007 and 3.39% in 2008; dividend yields of -0-%; volatility factors of the expected market price of the Company's common stock of 62% in 2006, 55% in 2007and 52% in 2008, determined by daily historical prices as well as other market indicators, and a weighted-average expected life of the option of 4.71 to 5.06 years in 2006, 7.14 years in 2007 and 7.86 in 2008.

Stock Options

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

The Company's 2005 Directors Plan (as defined below), has authorized the grant of options to directors for up to 900,000 shares of the Company's common stock. All options granted generally become fully exercisable over three to four years of continued service at 25% to 33% on each anniversary date or as specified by the Compensation Committee of the Board of Directors.

The Company's 2005 Employee Long-Term Equity Incentive Plan has authorized the grant of up to 2.1 million awards to management and employees, including options. 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

A summary of the Company's stock option activity for the three years ended December 31, 2008 follows:

	Options (000s)	Weighted-Average Exercise Price	Weighted Average Remaining Life	Intrinsic value Per Share
Options outstanding December 31, 2005	3,016	0.88		
Granted	190	5.29		
Exercised	(747)	0.87		
Forfeited/Expired	(2)	4.39		
Options outstanding December 31, 2006	2,457	$ 2.29		
Granted	383	3.75		
Exercised	(310)	1.12		
Forfeited/Expired	(4)	5.37		
Options outstanding December 31, 2007	2,526	$ 2.65		
Granted	86	4.37		
Exercised	(183)	1.37		
Forfeited/Expired	(39)	2.55		
Options outstanding December 31, 2008	2,390		5.15	$ 1.60
Exercisable at end of year	1,963	$	4.65	$ 1.42

Other information pertaining to option activity was as follows during the years ended December 31:

	2006	2007	2008
Weighted average grant-date fair value of stock options granted (per share)	$ 2.98	$ 2.26	$ 2.47
Total fair value of options vested (000's)	$ 890	$ 888	$ 1,022
Total intrinsic value of options exercised (000's)	$ 409	$ 256	$ 149

As of December 31, 2008 the total compensation cost related to non-vested awards not yet recognized is approximately $927,000, which will be recognized in 2009 through 2011.

The following table represents the range of option prices and the weighted average remaining life of outstanding options as of December 31, 2008 of:

	Options outstanding			Exercisable		
	Number Outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable	Weighted average remaining life	Weighted average exercise price
$0.50 – 0.97	802,957	2.62	$ 0.72	802,957	2.62	$ 0.71
$1.01 – 1.41	225,000	3.06	$ 1.19	225,000	3.06	$ 1.19
$2.06 – 2.75	92,857	5.10	$ 2.67	92,857	5.10	$ 2.67
$3.09 – 4.90	1,176,964	7.19	$ 4.31	796,631	6.99	$ 4.47
$6.05	92,000	6.39	$ 6.05	46,000	6.39	$ 6.05
	2,389,778			1,963,445		

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date. Compensation expense is recorded over the applicable restricted stock vesting periods. The Company did not award restricted shares prior to 2006.

A summary of the Company's restricted stock activity for the year ended December 31, 2008 is presented in the following table:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2006	—	$ —
Granted	152,736	3.60
Vested	—	—
Forfeited	(388)	—
Unvested December 31, 2007	152,348	3.60
Granted	55,952	2.85
Vested/Released	(41,061)	3.60
Forfeited	(2,959)	3.51
Unvested December 31, 2008	164,280	$ 3.35

Phantom Units

On January 31, 2008, in connection with the closing of the St. Mary acquisition, the Board of Directors of the general partner of the Partnership awarded phantom units with distribution equivalency rights under its long-term incentive plan to certain key employees of Abraxas Petroleum.

The phantom units and associated distribution equivalency rights will vest over four years and their value is based on the price of common units, as determined by the Board of Directors of the general partner of the Partnership, quarterly cash distributions and the percentage increase in cash distributions over time.

For the year ended December 31, 2008, the Partnership incurred equity based compensation expense of $242,000 relating to phantom units.

Director Stock Awards

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 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. In addition to the 10,000 shares or options, directors are compensated $12,000 per year, paid quarterly by issuance of common stock. During 2006, 2007, and 2008 there were 5,782; 22,960; and 30,655 shares, respectively, issued related to this compensation. The number of shares issued is determined based on the stock price on the date of issuance.

At December 31, 2008, the Company has approximately 1.5 million shares reserved for future issuance for conversion of its stock options, warrants, and incentive plans for the Company's directors, employees and consultants.

Warrants

On May 25, 2007, Abraxas entered into a Securities Purchase Agreement with certain accredited investors pursuant to which Abraxas issued warrants to purchase 1,174,938 shares of common stock, to the investors at a price of $3.83 per share. The warrants expire on May 25, 2012 and are exercisable at a price of $3.83 per share, subject to certain adjustments. During 2008, 182,768 warrants were exercised.

9. 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,		
	2006	2007	2008
	(In thousands)		
Deferred tax liabilities:			
Marketable securities	$ 261	$ 169	$ 33
U.S. full cost pool	10,806	—	—
Partnership interest	—	26,356	18,349
Total deferred tax liabilities	11,067	26,525	18,382
Deferred tax assets:			
U.S. full cost pool	—	135	418
Capital loss carryforward	4,234	5,010	—
Depletion carryforward	4,311	5,179	5,189
Net operating loss ("NOL") carryforward	67,429	60,067	68,034
Suspended losses	—	1,400	—
Alternative minimum tax credit	—	100	78
Allocated minority loss carryforward	—	—	3,267
Other	1,965	1,805	2,159
Total deferred tax assets	77,939	73,696	79,145
Valuation allowance for deferred tax assets	(66,872)	(47,171)	(60,763)
Net deferred tax assets	11,067	26,525	18,382
Net deferred tax	$ —	$ —	$ —

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

	Years ended December 31,		
	2006	2007	2008
	(in thousands)		
Current:			
Federal	$ –	$ 100	$ –
State	–	183	–
Foreign	–	–	–
	$ –	$ 283	$ –
Deferred:			
Federal	$ –	$ –	$ –
Foreign	–	–	–
	$ –	–	–

At December 31, 2008, the Company had, subject to the limitation discussed below, $194.4 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2014 through 2028 if not utilized.

In addition to any Section 382 limitations, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under SFAS Statement No. 109. Therefore, the Company has established a valuation allowance of $66.9 million for deferred tax assets at December 31, 2006 and $47.2 million at December 31, 2007 and $60.8 million at December 31, 2008.

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

	Years ended: December 31, 2006	2007	2008
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	$ (436)	$ (19,945)	$ 18,341
(Increase) Decrease in deferred tax asset valuation allowance	56	19,701	(13,592)
Expired capital loss carryforward	-	-	(4,742)
State margin tax	–	(183)	–
Permanent differences	(6)	(5)	(6)
Other	386	149	(1)
	$ –	$ (283)	$ –

10. Commitments and Contingencies

Operating Leases

During the years ended December 31, 2006, 2007 and 2008 the Company incurred rent expense related to leasing office facilities of approximately $252,000, $254,000 and $321,000 respectively. During 2008 the Company acquired a building for its corporate headquarters; accordingly there are no future minimum rental payments under such leases at December 31, 2008.

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, 2008 the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

11. Earnings per Share

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

	Years ended December 31: 2006	2007	2008
Numerator:			
Income (loss) from continuing operations	$ 700,000	$ 56,702,000	$ (52,403,000)
Denominator:			
Denominator for basic earnings per share – weighted-average common shares outstanding	42,578,584	46,336,825	49,004,918
Effect of dilutive securities:			
Stock options, restricted shares and warrants	1,283,797	1,256,670	—
Dilutive potential common shares			
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options, restricted shares and warrants	43,862,381	47,593,495	49,004,918
Net income (loss) per common share Basic	$ 0.02	$ 1.22	$ (1.07)
Net income (loss) per common share – Diluted	$ 0.02	$ 1.19	$ (1.07)

Basic earnings per share excludes any dilutive effects of options, warrants unvested restricted stock and convertible securities and is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share are computed similar to basic, however diluted earnings per share reflects the assumed conversion of all potentially dilutive securities. For the year ended December 31, 2008, 334,656 potential shares relating to stock options, were excluded from the calculation of diluted earnings per share since their inclusion would have been anti-dilutive due to the loss incurred in the period.

12. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2007 and 2008 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2007				
Net revenue	$ 11,651	$ 12,973	$ 11,404	$ 12,281
Operating income	$ 3,547	$ 4,840	$ 3,648	$ 3,489
Net income (loss)	$ (988)	$ 57,485(1)	$ 2,998	$ (2,793)
Net income (loss) per common share – basic	$ (0.02)	$ 1.29	$ 0.06	$ (0.06)
Net income (loss) per common share – diluted.	$ (0.02)	$ 1.27	$ 0.06	$ (0.06)
Year Ended December 31, 2008				
Net revenue	$ 22,170	$ 34,423	$ 29,246	$ 14,471
Operating income (loss)	$ 9,865	$ 19,183	$ 13,925	$ (116,990)(2)
Net income (loss)	$ (8,991)	$ (57,688)	$ 70,755(1)	$ (56,479)
Net income (loss) per common share – basic.	$ (0.18)	$ (1.18)	$ 1.44	$ (1.15)
Net income (loss) per common share – diluted	$ (0.18)	$ (1.18)	$ 1.43	$ (1.15)

(1) Includes gain on sale of interest in partnership of $59.4 million.
(2) Includes proved property impairment of $116.4 million, $7.1 million of losses not applicable to the minority interest, and a $0.3 million loss on conversion of Partnership units to Abraxas Petroleum common shares.

13. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees of the Company. The Company matched 50% of employee contributions in 2006 and 2007. Company contributions to the plan were $128,523 and $168,977 in 2006 and 2007, respectively. In 2008, in accordance with the safe harbor provisions of the plan the Company contributed $144,954 to the plan. 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 $15,000, $15,500 and $15,500 in 2006, 2007 and 2008, respectively. The contribution limit for 2006, 2007 and 2008 was $20,000, $20,500 and $20,500 for employees 50 years of age or older, respectively.

14. Hedging Program and Derivatives

The Company does not use hedge accounting rules as prescribed by SFAS 133 " Accounting for Derivative Instruments and Hedging Activities", and related interpretations. Accordingly, instruments are recorded on the balance sheet at their fair value with adjustments to the carrying value of the instruments being recognized in revenue in the current period.

Under the terms of the Partnership Credit Facility, Abraxas Energy Partners was required to enter into derivative contracts, or hedging arrangements, for specified volumes, which equated to approximately 85% of their estimated oil and gas production through December 31, 2011 from its net proved developed producing reserves. Abraxas Energy Partners has entered into NYMEX–based fixed price commodity swaps at then current market prices.

At December 31, 2008 the Partnership had the following oil and gas derivative contracts in place:

Period Covered	Product	Volume (Production per day)	Fixed Price
Year 2009	Gas	10,595 Mmbtu	$ 8.45
Year 2009	Oil	1,000 Bbl	$ 83.80
Year 2010	Gas	9,130 Mmbtu	$ 8.22
Year 2010	Oil	895 Bbl	$ 83.26
Year 2011	Gas	8,010 Mmbtu	$ 8.10
Year 2011	Oil	810Bbl	$ 86.45

In order to mitigate its interest rate exposure, the Partnership entered into an interest rate swap, effective August 12, 2008, to fix its floating LIBOR based debt. The 2-year interest rate swap arrangement is for $100 million at a fixed rate of 3.367%. The arrangement expires on August 12, 2010. The interest rate swap was amended in February 2009 lowering the Partnership's fixed rate from 3.367% to 2.95%.

15. Financial Instruments

SFAS 157—Effective January 1, 2008, the Company adopted Financial Accounting Standards Board ("FASB") Statement No. 157, *Fair Value Measurements* ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. The implementation of SFAS 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating a measure of the Company's own nonperformance risk or that of its counterparties as appropriate, which was not material. The primary impact from adoption was additional disclosures.

The Company elected to implement SFAS 157 with the one-year deferral permitted by FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement* No*. 157* ("FSP 157-2"), issued February 2008, which defers the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. As it relates to the Company, the deferral applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used.

Fair Value Hierarchy—SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2- inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter party to the derivative contract. The results of the assessment of non-performance risk, based on the counter party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following table presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2008
Assets:				
Investment in common stock	$ 113	$ —	$ —	$ 113
NYMEX Fixed Price Derivative contracts	—	39,226	—	39,226
Total Assets	$ 113	$ 39,226	$ —	$ 39,339
Liabilities:				
NYMEX Fixed Price Derivative contracts	$ —	$ —	$ —	$ —
Interest Rate Swaps	—	—	3,000	3,000
Total Liabilities	$ —	$ —	$ 3,000	$ 3,000

The Company has an investment in a former subsidiary consisting of shares of common stock. The stock is actively traded on the Toronto Stock Exchange. This investment is valued at its quoted price as of December 31, 2008 in US dollars. Accordingly this investment is characterized as Level 1.

The Partnership's derivative contracts consist of NYMEX-based fixed price commodity swaps and interest rate swaps, which are not traded on a public exchange. The NYMEX-based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity, and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2.

In August 2008, the Partnership entered into a two year interest rate swap. The notional amount is $100.0 million for the first year and $50.0 million for the second year. The Partnership will pay interest at 3.367% and be paid on a floating Libor rate. The interest rate swap was amended in February 2009 and increased the notional amount in the second year to $100.00 million and reduced the overall interest rate to 2.95%. As there is no actively traded market for this type of swap and no observable market parameters, these derivative contracts are classified as Level 3.

Additional information for the Partnership's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the year ended December 31, 2008 is as follows (in millions):

		Derivative Assets and (Liabilities) - net
Balance December 31, 2007	$	—
Total realized and unrealized losses included in change in net liability		(2,832)
Settlements during the period		(168)
Ending balance December 31, 2008	$	(3,000)

16. Minority interest in (income) loss of Partnership

The minority interest in the (income) loss of the Partnership represents the third parties 52.7% interest in the Partnership's net income/ loss. Additionally, in accordance with generally accepted accounting principles, when cumulative losses applicable to the minority interest exceed the minority interest equity capital in the entity, such excess and any further losses applicable to the minority interest are charged to the earnings of the majority interest. If future earnings are recognized by the minority interest, such earnings will then be credited to the majority interest (Abraxas) to the extent of such losses previously absorbed and any excess earnings will increase the recorded value. For the year ended December 31, 2008, primarily as a result of the ceiling test impairment of the Partnerships oil and gas properties, losses applicable to the minority interest exceeded the minority interest equity capital by $9.3 million and, as a result, $9.3 million of the minority interest loss in excess of equity was charged to earnings and was reflected as a reduction of the loss applicable to the minority interest.

17. Supplemental Oil and Gas Disclosures (Unaudited)

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

	December 31,	
	2007	2008
	(In thousands)	
Proved oil and gas properties	$ 265,090	$ 440,712
Unproved properties	–	–
Total	265,090	440,712
Accumulated depreciation, depletion, and amortization, and impairment	(148,550)	(287,993)
Net capitalized costs	$ 116,540	$ 152,719

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

	Years Ended December 31,		
	2006	2007	2008
		(In thousands)	
Development costs	$ 26,117	$ 16,793	$ 47,690
Exploration costs	—	—	1,920
Acquisition costs	—	10,000	127,671
	$ 26,117	$ 26,793	$ 177,281

The results of operations for oil and gas producing activities from continuing operations for the three years ended December 31, 2006, 2007 and 2008, respectively are as follows:

	Years Ended December 31,		
	2006	2007	2008
	(In thousands)		
Revenues	$ 49,448	$ 46,906	$ 99,084
Production costs	(11,776)	(11,254)	(26,634)
Depreciation, depletion, and amortization	(14,809)	(14,147)	(23,077)
Proved property impairment	—	—	(116,366)
General and administrative	(1,040)	(1,361)	(1,431)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 21,823	$ 20,144	$ (68,424)
Depletion rate per barrel of oil equivalent	$ 11.51	$ 12.58	$ 14.42

Estimated Quantities of Proved Oil and Gas Reserves

The following table presents the Company's estimate of its net proved oil and gas reserves as of December 31, 2006, 2007, and 2008 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. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company's proved reserves are located in the continental United States.

Proved reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, year-end prices and costs were used in estimating net cash flows.

	Liquid Hydrocarbons	Gas
	(Barrels)	(Mcf)
	(In thousands)	
Proved developed and undeveloped reserves:		
Balance at December 31, 2005	3,035	80,271
Revisions of previous estimates	(90)	(2,053)
Extensions and discoveries	11	440
Sales of minerals in place	—	(1,810)
Production	(200)	(6,515)
Balance at December 31, 2006	2,756	70,333
Revisions of previous estimates	541	8,652
Extensions and discoveries	31	14,586
Production	(197)	(5,568)
Balance at December 31, 2007 (1)	3,131	88,003
Revisions of previous estimates	(1,651)	(6,160)
Extensions and discoveries	459	5,863
Purchases of minerals in place	5,684	27,110
Sales of minerals in place	(27)	(56)
Production	(550)	(6,343)
Balance at December 31, 2008 (1)	7,046	108,417

	Liquid Hydrocarbons	Gas
	(Barrels)	(Mcf)
Proved developed reserves:		
December 31, 2006	1,708	37,333
December 31, 2007 (1)	2,184	33,908
December 31, 2008 (1)	5,563	48,209

(1) Proved reserves at December 31, 2007 and 2008 include 1,206 barrels and 4,478 barrels of oil, respectively and 65,460 and 83,406 Mcf of gas, respectively attributable to the Partnership in which there is a 52.8% and 52.9% minority interest, respectively.

Reserve extensions and discoveries which increased significantly during 2007 were primarily attributable to the Yoakum (Edwards) field in the Gulf Coast region. Other operators in neighboring fields have been successful with closer spacing and new completion techniques which resulted in the booking of additional proved undeveloped reserves in our field. Revisions of previous estimates which increased appreciably during 2007 were primarily attributable to higher commodity prices at December 31, 2007 over the prior year-end which extends the economic life of many wells and thus, increases reserves estimates.

Purchases of minerals in place increased significantly during 2008 which was attributable to the acquisition of oil and gas properties from St. Mary in January 2008. Revisions of previous estimates which decreased appreciably during 2008 was primarily attributable to lower commodity prices at December 31, 2008 over the prior year-end which shortens the economic life of many wells and thus, decreases reserve estimates.

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 oil and 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 oil and 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, 2008 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 ended December 31, 2006, 2007 and 2008.

	Years Ended December 31,		
	2006	2007	2008
	(In thousands)		
Future cash inflows	$ 567,805	$ 830,193	$ 811,644
Future production costs	(169,805)	(235,146)	(312,756)
Future development costs	(73,377)	(111,221)	(134,073)
Future income tax expense	—	—	—
Future net cash flows	324,623	483,826	364,815
Discount	(167,779)	(268,140)	(212,823)
Standardized Measure of discounted future net cash relating to proved reserves (1)	$ 156,844	$ 215,686	$ 151,992

(1) The standardized measure of discounted future cash flows included $147,750 and $118,570 at December 31, 2007 and 2008, respectively attributable to the Partnership in which there was a 52.8% and 52.9% minority interest, respectively.

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,		
	2006	2007	2008
	(In thousands)		
Standardized Measure – beginning of year	$ 309,895	$ 156,844	$215,686
Sales and transfers of oil and gas produced, net of production costs	(38,318)	(35,652)	(72,449)
Net change in prices and development and production costs from prior year	(114,517)	44,791	(69,094)
Extensions, discoveries, and improved recovery, less related costs	914	29,834	8,694
Purchases of minerals in place	—	—	61,761
Sales of minerals in place	(3,268)	—	(366)
Revisions of previous quantity estimates	(15,914)	24,033	(16,222)
Change in timing and other	(12,937)	(19,847)	2,414
Accretion of discount	30,989	15,683	21,568
Standardized Measure, end of year	$ 156,844	$ 215,686	$151,992

CORPORATE INFORMATION

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DeGolyer and MacNaughton
Dallas, Texas

Stock Exchange Listing
NASDAQ Stock Exchange
Ticker Symbol: AXAS

Transfer Agent
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Phone: 800.937.5449

Annual Shareholders Meeting
May 21, 2009 at 9:00 a.m. CT
Petroleum Club
San Antonio, Texas

OFFICERS

Robert L.G. Watson
President / Chief Executive Officer

Chris E. Williford
Executive Vice President /
Chief Financial Officer

Lee T. Billingsley, Ph.D.
Vice President - Exploration

William H. Wallace
Vice President - Operations

Stephen T. Wendel
Vice President - Land and Marketing

Barbara M. Stuckey
Vice President - Corporate Development

DIRECTORS

Robert L.G. Watson
Chairman of the Board / President /
Chief Executive Officer,
Abraxas Petroleum Corporation
San Antonio, Texas

C. Scott Bartlett, Jr. [1]
Executive Vice President (retired),
Bank of America
Richmond Hill, Georgia

Franklin A. Burke [1]
President, Venture Securities Corporation;
President / Chief Executive Officer,
Burke, Lawton, Brewer & Burke
Ambler, Pennsylvania

Harold D. Carter [2]
Former President / Chief Operating Officer,
Sabine Corporation
Dallas, Texas

Ralph F. Cox [2,3]
President, Rabar Enterprises
Fort Worth, Texas

Dennis E. Logue [2,3]
Chairman of the Board,
Ledyard National Bank
Hanover, New Hampshire

Paul A. Powell, Jr. [1,3]
Vice President / Director,
Machine Development Co.,
Salem, Virginia

[1] Audit Committee
[2] Compensation Committee
[3] Nominating & Governance Committee

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