ABRAXAS PETROLEUM CORP
Form 10-K
March 18, 2010

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2009

o 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 (State or Other Jurisdiction of Incorporation or Organization)	74-2584033 (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	The NASDAQ Stock Market, LLC
Preferred Stock Purchase Rights	The NASDAQ Stock Market, LLC

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 o No x

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

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 the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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.(check one):

Large accelerated filer	Accelerated filer
Non-accelerated filer x (Do not check if a smaller reporting company)	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 x

As of June 30, 2009, the last day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the common stock held by non-affiliates of the registrant was $43,053,752 based on the closing sale price as reported on The NASDAQ Stock Market

As of March 12, 2010, there were 76,230,187 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2010 Annual Meeting of Shareholders to be held on May 19, 2010.	Part III

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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,” “will,” “plan,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this document is generally located in the material set forth under the headings “Business,” “Risk Factors,” “Properties,” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- our 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;
- 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;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- results of our hedging activities; and
- other factors discussed elsewhere in this document.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the State or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or NGLs.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

"Bbl" – barrel or barrels.

"Bcf" – billion cubic feet of gas.

"Bcfe" – billion cubic feet of gas equivalent.

"Boe" – barrels of oil equivalent.

“Boepd” – barrels of oil equivalent per day.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

“Mcfe” – thousand cubic feet of gas equivalent.

“MMBbls” – million barrels.

“MMBoe” – million barrels of oil equivalent.

“MMbtu” – million British Thermal Units.

“MMcf” – million cubic feet of gas.

“MMcfe” – million cubic feet of gas equivalent.

“MMcfepd” – million cubic feet of gas equivalent per day.

“MMcfpd” – million cubic feet of gas per day.

Terms used to describe our interests in wells and acreage:

“Developed acreage” means acreage which consists of leased acres spaced or assignable to productive wells.

“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.

“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.

“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.

“Gross” means gross acres refer to the number of acres in which we own a working interest.

“Gross well” is a well in which we own an interest.

“Net acres” are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

“Net well” is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"Productive well" is an exploratory or a development well that is not a dry hole.

"Undeveloped acreage" means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

"Proved reserves" or "reserves" means oil and gas, condensate and NGLs on a net revenue interest basis, found to be commercially recoverable.

"Probable reserves" are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.

"Possible reserves" are those additional reserves which analysis of geosciences and engineering data suggest are less likely to be recoverable than probable reserves.

"Proved undeveloped reserves" includes those proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"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 SEC.

"Standardized Measure" means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation, calculated in accordance with ASC 932, formerly Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities."

Part I

Item 1. Business

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. On October 5, 2009, Abraxas Petroleum Corporation acquired 100% ownership of the Partnership, which we refer to as the Merger. The non-controlling interest of the former limited partners of the Partnership is presented as non-controlling interest in the accompanying Consolidated Statement of Operations through the date that their interest was acquired by Abraxas. The terms "Abraxas," "we," "us," "our," or the "Company," re 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 exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a 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, 2009, our properties were located in the Rocky Mountain, Mid-Continent, Permian Basin and Gulf Coast regions of the United States. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2009:

	Gross Producing Wells	Average Working Interest		Estimated Net Proved Reserves (MMBOE)	Net Production (MBOE)
Rocky Mountain	900	12	%	7,237.1	434.8
Mid-Continent	617	14	%	3,109.0	263.1
Permian Basin	237	67	%	5,541.8	500.5
Gulf Coast	74	64	%	9,031.9	435.2
Total	1,828	22	%	24,919.8	1,633.6

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, and the underlying Three Forks.

- 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 900 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 down 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 617 gross (89 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, Texas 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, Texas 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, Texas 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 237 gross (158 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, Texas and consist of wells that produce gas from the Edwards formation at a depth of 13,500 feet.

- Portilla—Our properties in the Portilla field are located in San Patricio County, Texas, were discovered in 1950 by The Superior Oil Company, predecessor to Mobil Oil Corporation, and consist 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, DeWitt and Karnes Counties, Texas 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 74 gross (48 net) producing wells in the Gulf Coast region.

Recent Developments

Merger Agreement

On June 30, 2009, Abraxas Petroleum and Abraxas Energy Partners signed an Agreement and Plan of Merger, which we refer to as the Original Merger Agreement, pursuant to which Abraxas Energy agreed to merge with and into Abraxas Petroleum with Abraxas Petroleum surviving and on July 17, 2009, Abraxas Petroleum, Abraxas Energy Partners and Abraxas Merger Dub, LLC, which we refer to as Merger Sub, signed an Amended and Restated Agreement and Plan of Merger, which we refer to as the Merger

Agreement, pursuant to which Abraxas Energy Partners agreed to merge with and into Merger Sub with Merger Sub surviving the merger as a wholly-owned subsidiary of Abraxas Petroleum. We refer to this merger as the Merger. Under the terms of the Merger Agreement, at the effective time of the Merger on October 5, 2009, which we refer to as the Effective Time, the common units of Abraxas Energy Partners not owned by Abraxas Petroleum and its subsidiaries were converted into the right to receive 4.25 shares of Abraxas Petroleum common stock for each Abraxas Energy Partners common unit not owned by Abraxas Petroleum or its subsidiaries. We issued a total of 26,174,061 shares of our common stock in the Merger, including 420,552 shares of restricted common stock issued in exchange for restricted units and phantom units of Abraxas Energy Partners under the Abraxas Petroleum Corporation 2005 Long-Term Equity Incentive Plan, or LTIP.

Credit Facility

Simultaneously with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. In connection with the Merger, we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion. As of December 31, 2009, $138.5 million was outstanding under the revolving portion and $8.0 million was outstanding under the term portion. For more information about the credit facility, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Indebtedness—Credit Facility.

2010 Capital Budget

We anticipate making capital expenditures of $30.0 million in 2010 for the development of our existing properties. The capital program for 2010 will be selected from our inventory of projects and will include new drills and re-completions / workovers in our primary producing regions of the Rocky Mountain, Mid-Continent, Permian Basin and onshore Gulf Coast. The ultimate mix of projects will be based on commodity prices, services costs and drilling results but will predominately target oil projects. These anticipated expenditures are subject to adequate cash flow from operations and availability under the credit facility.

Non-Core Divestitures

We have initiated a divestiture program, principally aimed at non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. During the fourth quarter of 2009 and the first quarter of 2010, we have sold certain non-core assets for combined net proceeds of approximately $11.2 million ($2.4 million in 2009 and $8.8 million in 2010). In total, these properties produced approximately 142 Boepd (approximately 3% of our daily net production) and had approximately 606 MBoe of proved reserves (approximately 2% of our net proved reserves), which equates to $78,385 per producing Boepd and $18.41 per proved Boe. The first $10 million of net proceeds will be used to repay the term loan portion of our credit facility after which, any net proceeds will be allocated approximately 50% for further debt reduction and 50% to accelerate our capital program. We have identified an additional $20 to $30 million of similar non-core assets that we will attempt to divest on similar terms over the next several months.

Tax Benefits Preservation Plan

On March 16, 2010, our board of directors adopted a Tax Benefits Preservation Plan (the "Tax Benefits Preservation Plan") and declared a dividend of one preferred share purchase right for each outstanding share of Abraxas common stock. The dividend is payable to our stockholders of record as of March 16, 2010. The terms of the rights and the

Tax Benefits Preservation Plan are set forth in a Rights Agreement, by and between us and American Stock Transfer & Trust Company, as Rights Agent, dated as of March 16, 2010.

This summary of rights provides only a general description of the Tax Benefits Preservation Plan.

We adopted the Tax Benefits Preservation Plan in an effort to protect stockholder value by attempting to protect against a possible limitation on our ability to use our net operating loss carryforwards, or NOL's, to reduce potential future federal income tax obligations. We have experienced and continue to experience substantial operating losses, and under the Internal Revenue Code and rules promulgated by the

Internal Revenue Service, we may "carry forward" these losses in certain circumstances to offset any current and future earnings and thus reduce our federal income tax liability, subject to certain requirements and restrictions. To the extent that the NOLs do not otherwise become limited, we believe that we will be able to carry forward a significant amount of NOLs, and therefore these NOLs could be a substantial asset to us. However, if we experience an "Ownership Change," as defined in Section 382 of the Internal Revenue Code, our ability to use the NOLs will be substantially limited, and the timing of the usage of the NOLs could be substantially delayed, which could therefore significantly impair the value of that asset. As of December 31, 2009, we had net operating loss carryforwards of $121.7 million.

The Tax Benefits Preservation Plan is intended to act as a deterrent to any person or group acquiring 4.9% or more of our outstanding common stock, or an Acquiring Person, without our approval. Stockholders who own 4.9% or more of our outstanding common stock as of the close of business on March 16, 2010 will not trigger the Tax Benefits Preservation Plan so long as they do not (i) acquire any additional shares of common stock or (ii) fall under 4.9% ownership of common stock and then re−acquire 4.9% or more of the common stock. The Tax Benefits Preservation Plan does not exempt any future acquisitions of common stock by such persons. Any rights held by an Acquiring Person are null and void and may not be exercised. We may, in our sole discretion, exempt any person or group from being deemed an Acquiring Person for purposes of the Tax Benefits Preservation Plan.

The Rights. We authorized the issuance of one right per each outstanding share of our common stock payable to our stockholders of record as of March 16, 2010. Subject to the terms, provisions and conditions of the Tax Benefits Preservation Plan, if the rights become exercisable, each right would initially represent the right to purchase from us one one−thousandth of a share of our Series 2010 Junior Participating Preferred Stock ("Series 2010 Preferred Stock") for a purchase price of $7.00 (the "Purchase Price") . If issued, each fractional share of Series 2010 Junior Preferred Stock would give the stockholder approximately the same dividend, voting and liquidation rights as does one share of our common stock. However, prior to exercise, a right does not give its holder any rights as a stockholder of the Company, including without limitation any dividend, voting or liquidation rights.

Series 2010 Preferred Stock Provisions. Each one one-thousandth of a share of Series 2010 Preferred Stock, if issued: (1) will not be redeemable; (2) will entitle holders to quarterly dividend payments of $0.01 per one one-thousandth of a share of Series 2010 Preferred Stock, or an amount equal to the dividend paid on one share of common stock, whichever is greater, if, as and when declared by our board of directors out of funds legally available therefor; (3) will entitle holders upon liquidation either to receive $1.00 per one one-thousandth of a share of Series 2010 Preferred Stock or an amount equal to the payment made on one share of common stock, whichever is greater; (4) will have the same voting power as one share of common stock; and (5) if shares of our common stock are exchanged via merger, consolidation, or a similar transaction, will entitle holders to a per share payment equal to the payment made on one share of common stock. The value of one one-thousandth interest in a Preferred Share should approximate the value of one share of common stock.

Exercisability. The rights will not be exercisable until the earlier of (i) 10 business days after a public announcement by us that a person or group has become an Acquiring Person or (ii) 10 business days after the commencement of a tender or exchange offer by a person or group for 4.9% of the common stock.

We refer to the date that the rights become exercisable as the "Distribution Date." Until the Distribution Date, our common stock certificates will evidence the rights and will contain a notation to that effect. Any transfer of shares of common stock prior to the Distribution Date will constitute a transfer of the associated rights. After the Distribution Date, the rights may be transferred other than in connection with the transfer of the underlying shares of common stock.

After the Distribution Date, each holder of a right, other than rights beneficially owned by the Acquiring Person (which will thereupon become void), will thereafter have the right to receive upon exercise of a right and payment of the Purchase Price, that number of shares of common stock having a market value at the time of exercise of two times the Purchase Price.

Exchange. After the Distribution Date, we may exchange the rights (other than rights owned by an Acquiring Person, which will have become void), in whole or in part, at an exchange ratio of one share of common stock, or a fractional share of Series 2010 Preferred Stock (or of a share of a similar class or series of the Company’s preferred stock having similar rights, preferences and privileges) of equivalent value, per right (subject to adjustment).

Expiration. The rights and the Tax Benefits Preservation Plan will expire on the earliest of (i) March 16 2015, (ii) the time at which the rights are redeemed pursuant to the Rights Agreement, (iii) the time at which the rights are exchanged pursuant to the Rights Agreement, (iv) the repeal of Section 382 of the Code or any successor statute if we determine that the Rights Agreement is no longer necessary for the preservation of NOLs and (v) the beginning of a taxable year of the Company of which we determine that no NOLs may be carried forward.

Redemption. At any time prior to the time an Acquiring Person becomes such, we may redeem the rights in whole, but not in part, at a price of $0.01 per right (the "Redemption Price"). The redemption of the rights may be made effective at such time, on such basis and with such conditions as we in our sole discretion may establish. Immediately upon any redemption of the rights, the right to exercise the rights will terminate and the only right of the holders of rights will be to receive the Redemption Price.

Anti−Dilution Provisions. We may adjust the purchase price of the shares of Series 2010 Preferred Stock, the number of shares Series 2010 Preferred Stock issuable and the number of outstanding rights to prevent dilution that may occur as a result of certain events, including among others, a stock dividend, a stock split or a reclassification of the shares of Series 2010 Preferred Stock or our common stock. No adjustments to the purchase price of less than 1% will be made.

Amendments. Before the Distribution Date, we may amend or supplement the Tax Benefits Preservation Plan without the consent of the holders of the rights. After the Distribution Date, we may amend or supplement the Tax Benefits Preservation Plan only to cure an ambiguity, to alter time period provisions, to correct inconsistent provisions, or to make any additional changes to the Tax Benefits Preservation Plan, but only to the extent that those changes do not impair or adversely affect any rights holder.

The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group who attempts to acquire the Company on terms not approved by us. The rights should not interfere with any merger or other business combination approved by us since we may redeem the rights at $0.01 per right at any time until the date on which a person or group has become an Acquiring Person.

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 12 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, 2009, two purchasers accounted for approximately 21% of our gas sales, and no single purchaser accounted for more that 10% of our oil sales. We believe that there are numerous other purchasers available to buy 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 properties 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.

Federal, state and local laws and regulations govern oil and gas activities. Operators of oil and gas properties are required to have a number of permits in order to operate such properties, including operator permits and permits to dispose of salt water. We possess all material requisite permits required by the states and other local authorities in which we operate properties. In addition, under federal law, operators of oil and gas properties are required to possess certain certificates and permits in order to operate such properties such as hazardous materials certificates, which we have obtained.

Development and Production

The operations of our properties are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring the operator of oil and gas properties to possess permits for the drilling and development of wells, post bonds in connection with various types of activities, and file reports concerning operations. Most states, and some counties and municipalities in which we operate, regulate one or more of the following:

- the location of wells;
- the method of developing and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

Some states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some states allow forced pooling or unitization of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from their wells or limit the number of wells or the locations at which these wells can be drilled. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Operations on Federal or Indian oil and gas leases 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, including the Bureau of Land Management, which we refer to as BLM, and the Minerals Management Service, which we refer to as MMS. MMS establishes the basis for royalty payments due under federal oil and natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and natural gas leases. Accordingly, we believe that the impact of royalty regulation on the operations of our properties should generally be the same as the impact on our competitors. We believe that the operations of our properties are in material compliance with all applicable regulations as they pertain to Federal or Indian oil and gas leases.

The failure to comply with these rules and regulations can result in substantial penalties, including lease suspension or termination in the case of federal leases. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect us.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended, which we refer to as NGA, the Natural Gas Policy Act of 1978, as amended, which we refer to as NGPA, and regulations promulgated thereunder by the

Federal Energy Regulatory Commission, which we refer to as FERC and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended, which we refer to as the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders, which we refer to, collectively, as Order No. 636, to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. FERC continues to regulate the rates that interstate pipelines may charge for such transportation and storage services. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders, which we refer to, collectively, as Order No. 637, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Energy Policy Act of 2005, which we refer to as EP Act 2005, gave FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended the NGA to prohibit market manipulation and also amended the NGA and the NGPA to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of FERC to up to $1,000,000 per day, per violation. In addition, FERC issued a final rule effective January 26, 2006, regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC jurisdiction, to defraud, make an untrue statement, or omit a material fact or engage in any practice, act, or course of business that operates or would operate as a fraud. This final rule works together with FERC's enhanced penalty authority to provide increased oversight of the natural gas marketplace.

The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Generally, intrastate natural gas transportation is subject to regulation by state regulatory agencies, although FERC does regulate the rates, terms, and conditions of service provided by intrastate pipelines that transport gas subject to FERC's NGA jurisdiction pursuant to Section 311 of the NGPA. The basis for state regulation of intrastate natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

Natural Gas Gathering

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. FERC has developed tests for determining which facilities constitute jurisdictional transportation facilities under the NGA and which facilities constitute gathering facilities exempt for FERC's NGA jurisdiction. From time to time, FERC reconsiders its test for defining non-jurisdictional gathering. For example, there is currently pending at FERC a proposed rulemaking to reformulate its test for non-jurisdictional gathering in the shallow waters of the Outer Continental Shelf. In recent years, FERC has also permitted jurisdictional pipelines to "spin down" exempt gathering facilities into affiliated entities that are not subject to FERC jurisdiction, although FERC continues to examine the circumstances in which such a "spin down" is appropriate and whether it should reassert jurisdiction over certain gathering companies and facilities that previously had been "spun down." We cannot predict the effect that FERC's activities in this regard may have on the operations of our properties, but we do not expect these activities to affect the operations in any way that is materially different from the effect thereof on our competitors.

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.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, FERC, in February 2003, increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Environmental Matters

Oil and gas operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, storage and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, and natural gas processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, areas inhabited by threatened or endangered species and other protected areas;

- require remedial measures to mitigate pollution from historical and on-going operations such as the 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 that the operators of properties are required to possess 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 our operations 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 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 respective financial positions or results of operations. Moreover, we maintain insurance against the 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.

The following is a discussion of the current relevant environmental laws and regulations that relate to our operations.

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 our ordinary operations, certain wastes may be generated that may fall within CERCLA’s definition of a “hazardous substance.” We may be 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 we have 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. Federal regulations also require certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The Federal Oil Pollution Act, which we refer to as OPA, contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. 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 our financial position or results of operations.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid 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 wastes to be classified and regulated as non-hazardous wastes. A similar exemption is contained in many of the state counterparts to RCRA. 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 wastes. 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 and would cause us to incur increased operating expenses. Also, in the ordinary course of our operations, we generate small amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

Naturally Occurring Radioactive Materials, which we refer to as 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 the operations of our properties are in material compliance with all applicable NORM standards established by the various states in which we operate wells.

Clean Water Act. The Clean Water Act, which we refer to as the CWA, and analogous state laws, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of the CWA require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA 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 the operations of our properties comply in all material respects with the requirements of the CWA and state statutes enacted to control water pollution.

Safe Drinking Water Act. Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act, which we refer to as the SDWA, and analogous state and local laws. 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 main goal of the SDWA is 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 most states, 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 natural 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 natural 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 natural 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.

Hydraulic Fracturing. Many of our operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Climate change legislation and greenhouse gas regulation. Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response to these studies, many nations have agreed to limit emissions of “greenhouse gases” or “GHGs” pursuant to the United Nations Framework Convention on Climate Change, and the “Kyoto Protocol.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered “greenhouse gases” regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in Massachusetts, et al. v. EPA, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The emissions will be published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has proposed two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and natural gas exploration and production industry and the pipeline industry. The EPA's finding, the greenhouse gas reporting rule, and the proposed rules to regulate the emissions of greenhouse gases would result in federal regulation of carbon dioxide emissions and other greenhouse gases, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

On June 26, 2009, the United States House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” or ACESA. On November 5, 2009 the Senate Committee on Environment and Public Works approved the “Clean Energy Jobs and American Power Act of 2009,” authored by John Kerry and Barbara Boxer, that is similar in many ways to ACESA. One of the purposes of these bills is to control and reduce emissions of greenhouse gases in the United States. These bills would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% to 20% (from 2005 levels) by 2020, and by over 80% by 2050. Under these bills, most sources of GHG emissions would be required to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet the overall emission reduction goals of the bills. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of these bills would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. President Obama has indicated that he is in support of the adoption of legislation such as the two bills discussed above, and the White House is expending significant efforts to push for the legislation.

Two recent court decisions, one before the United States Second Circuit Court of Appeals and one before the United States Fifth Circuit Court of Appeals have allowed GHG related cases to proceed. In the first case, Connecticut v. American Electric Power, the Second Circuit ruled that several states and other plaintiffs could continue a suit to impose GHG reductions on several utility defendants, concluding that a political question and standing objections of the defendants did not prohibit the suit from going forward. The Fifth Circuit, in Comer v. Murphy Oil, ruled that plaintiffs could similarly pursue a damage suit and the political question did not prohibit the suit. This case involves claims by plaintiffs who suffered damages from Hurricane Katrina that are seeking to recover damages from certain GHG emitters asserting their emissions contributed to their increased damages. In another case filed in the State District Court in Austin, Texas on October 6, 2009, a citizens group sued the Texas Commission on Environmental Quality (TCEQ) asserting that the agency was required to regulate carbon dioxide emissions from parties applying for permits under the Texas Clean Air Act. The result of this lawsuit could impose additional regulations on our operations, if the Texas courts require the TCEQ to regulate carbon dioxide and perhaps other GHGs such as methane, and these rules are applied to our operations in Texas. We may be subject to the EPA GHG monitoring and reporting rule, and potentially new EPA permitting rules if adopted to apply GHG permitting obligations and emissions limitations under the federal Clean Air Act. Even if no federal greenhouse gas regulations are enacted, or if the EPA issues regulations, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

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 properties 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 at some time in the future. We have posted bonds with most regulatory agencies to ensure compliance with their 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 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.

Employees

As of March 12, 2010, we had 70 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 have substantial indebtedness which may adversely affect our cash flow and business operations.

At December 31, 2009, we had a total of $146.5 million of indebtedness under our credit facility. Our indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- covenants contained in our credit facility and future debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- we may need a substantial portion of our cash flow from operations to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and

- our level of debt will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally, than our competitors with less debt.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying acquisitions and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness or seeking additional debt or equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of the credit facility, including the inability to comply with the required financial covenants, could result in an event of default. If an event of default occurs (after any applicable notice and cure periods), the lenders would be entitled to terminate any commitment to make further extensions of credit under the credit facility and to accelerate the repayment of amounts outstanding (including accrued and unpaid interest and fees). Upon a default under the credit facility, the lenders could also foreclose against any collateral securing such obligations, which may be all or substantially all of our assets. If that occurred, we may not be able to continue to operate as a going concern.

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

We must make 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. We cannot assure you that we will have sufficient capital resources in the future to finance all of our planned capital expenditures.

Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of 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 base under our credit facility will be determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under the credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/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 base decrease for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under the credit facility is reduced, we would be required to reduce our borrowings under the credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, we may be in default under the credit facility.

We have sold producing properties to provide us with liquidity and capital resources in the past and we may continue to do so in the future. After any such sale, we would expect to utilize the proceeds to reduce our indebtedness and to drill new wells on our remaining properties. If we cannot replace the production lost from properties sold with production from the remaining properties, our cash flow from operations 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 93% of the estimated ultimate recovery of our proved developed producing reserves as of December 31, 2009 had been produced. Based on the reserve information set forth in our reserve report as of December 31, 2009, our average annual estimated decline rate for our net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. As our proved reserves and consequently our production decline, our cash flow from operations, and the amount that we are able to borrow under our credit facility will also decline. In addition, approximately 44% of our total estimated proved reserves at December 31, 2009 were classified as 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 44% of our total estimated proved reserves as of December 31, 2009 were classified as 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 will decrease.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors that are beyond our control or not covered by insurance.

Our drilling operations are subject to a number of risks, 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;

- title problems;

- unusual or unexpected geological formations;
- pipeline ruptures;
- fires, blowouts and explosions; and
- uncontrollable flows of oil or gas or well fluids.

Any of these events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension of operations, and attorney’s fees and other expenses incurred in the prosecution or defense of litigation.

We maintain insurance against some but not all of these risks. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

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.

Our credit facility contains a number of significant covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- make any change in the principal nature of our business;
- permit a change of control; or
- consolidate, merge or transfer all or substantially all of our assets.

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

A breach of any of these covenants could result in a default under our 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 oil and 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 our oil and gas are typically 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 2009, differentials averaged $7.67 per Bbl of oil and $0.70 per Mcf of gas. Approximately 43% of our production during 2009 was from the Rocky Mountain and Mid-Continent regions. 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.

Our derivative contracts 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 our credit facility, we 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. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 85% of the oil and gas production from our estimated net proved developed producing reserves through December 31, 2012 and 70% for 2013 in order to comply with the requirements of our credit facility. Any new hedging arrangements will be priced at then-current market prices and may be significantly lower than the commodity swaps we currently have in place. The extent of our commodity price exposure will be related largely to the effectiveness and scope of our commodity price derivative contract activities. For example, the prices utilized in our derivative instruments are currently 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 typically 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 from operations 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 from operations 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 we hedge our oil and gas production are less than current market prices, our cash flow from operations could be adversely affected.

When our derivative contract prices are higher than market prices, we will incur realized and unrealized gains on our derivative contracts and when our contract prices are lower than market prices, we will incur realized and unrealized losses. For the year ended December 31, 2009, we recognized a realized gain on oil and gas derivative contracts of $17.9 million and an unrealized loss of $28.4 million. The realized gain resulted in an increase in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility. On July 29, 2009, we entered into hedging arrangements for specified volumes, which equate to approximately 85% of the estimated oil and gas production from our proved developed producing reserves through December 31, 2012 and 70% for 2013.

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.

The counterparties to our derivative contracts may be unable to perform their obligations to us which could adversely affect our cash flow.

At times when market prices are lower than our derivative contract prices, we are entitled to payments from our counterparties. The worldwide financial and credit crisis may adversely affect the ability of our counterparties to fulfill their contractual obligations to us. If one of our counterparties is unable or unwilling to make the required payments to us, it could adversely affect our cash flow.

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, which could be further impacted by the new modernized oil and gas reporting disclosures, which requires us to use an average price over the prior 12-month period, rather than the year-end price. 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 oil and gas prices may have increased the ceiling applicable to the subsequent period.

At December 31, 2009, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. However, 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 write downs in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2009, we had, subject to the limitation discussed below, $121.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire in varying amounts through 2028 if not otherwise used.

The use of our net operating loss carryforwards may be limited if an “ownership change” of over 50 percentage points occurs during any three-year period. Based on current estimates, we believe that we have not surpassed this threshold. It is feasible that even a modest change of ownership (including, but not limited to, a shift in common stock ownership by one reasonably large stockholder or any offering of common stock) during the three-year period following the Merger, which was consummated on October 5, 2009, could trigger a significant limitation of the amount of such net operating loss carryforwards available to offset future taxable income.

Additionally, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10. Therefore, we have established a valuation allowance of $47.2 million for deferred tax assets at December 31, 2007, $60.8 million at December 31, 2008 and $91.5 million at December 31, 2009.

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.

Our financial statements are complex.

Due to the nature of our business, and accounting principles generally accepted in the United States of America, our financial statements continue to be complex, particularly with reference to derivative contracts, asset retirement obligations, equity awards, deferred taxes and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

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 65% of our proved reserves were gas at December 31, 2009. 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 gas prices remain depressed or oil prices decline significantly, 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 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, capital 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 our reserves set forth in this document. 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 as of December 31, 2009, 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 the twelve month un-weighted first-day-of-the-month average oil and gas prices for the year ended December 31, 2009. The average realized sales prices as of such date used for purposes of such estimates were $3.42 per Mcf of gas and $55.05 per Bbl of oil. This compares with average realized sales prices of $4.77 per Mcf of gas and $41.74 per Bbl of oil as of December 31, 2008. The December 31, 2009 estimates also assume that we will make future capital expenditures of approximately $138.4 million in the aggregate primarily from 2010 through 2014, which are necessary to develop and realize the value of proved reserves on our properties. In addition, approximately 44% of our total estimated proved reserves as of December 31, 2009 were classified as 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 our reserves set forth or incorporated by reference in this document.

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 based the December 31, 2009 estimated discounted future net cash flows from our proved reserves on the twelve month un-weighted first-day-of-the-month average oil and gas 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 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 could be 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 wages of, qualified drilling rig crews rise as the number of active rigs in service increases. When oil and gas prices are high, the demand for oilfield services rises and the cost of these services increases.

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 from 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.

Proposed federal legislation concerning tax deductions currently available with respect to oil and gas drilling may adversely affect our net earnings and proposed legislative initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions and delays.

The Obama administration has proposed the outright elimination of many of the key federal income tax benefits historically associated with the oil and gas industry. Although presented in very summary form, among other significant energy tax items, the administration's budget appears to propose the complete elimination of (i) expensing of intangible drilling costs, and (ii) the "percentage depletion" method of deduction with respect to oil and gas wells. Although no legislation has been formally introduced, if this proposal (or others) is enacted into law, it could adversely affect our net earnings.

Additionally, Congress is currently considering legislation to amend the Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells. The sponsors of the bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process as well as additional levels of regulation that could lead to operational restrictions and delays and increased operating costs.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs. At the federal level, in June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill or ACESA. The United States Senate passed out of committee the Clean Energy Jobs and American Power Act, also known as the Kerry-Boxer Bill. Although these bills differ in certain ways, they both contain provisions that would establish a cap and trade system for restricting greenhouse gas emissions in the United States. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this federal legislative initiative remains uncertain.

In addition to pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules this year.

In the courts, several decisions have been issued that may increase the risk of claims being filed by government entities and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and gas that we produce.

Risks Related to Our Common Stock

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

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

We cannot pay dividends on common stock.

We have never paid a cash dividend on our common stock and the terms of the credit facility prohibit us from paying dividends on our common stock.

Shares eligible for future sale may depress our stock price.

At December 31, 2009, we had 76,231,751 shares of common stock outstanding of which 5,836,963 shares were held by affiliates and, in addition, 4,089,892 shares of common stock were subject to outstanding options granted under stock option plans (of which 1,807,622 shares were vested at December 31, 2009).

All of the shares of common stock held by affiliates are restricted or control securities under Rule 144 promulgated under the Securities Act of 1933, as amended. The shares of common stock issuable upon exercise of 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 our common stock and could impair our ability to raise additional capital through the sale of equity securities.

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

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

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

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

Subject to the rules of The NASDAQ Stock Market, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock. On March 16, 2010, our board of directors adopted a tax benefits preservation plan and declared a dividend of one preferred share purchase right for each outstanding share of our common stock. These rights are only activated if the plan is triggered by any person or group acquiring 4.9% or more of our outstanding common stock without our approval.

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

Our articles of incorporation and bylaws provide for a classified board of directors, with each member serving a three-year term, and eliminate the ability of stockholders to call special meetings or take action by written consent. Each of the provisions in the articles of incorporation, bylaws and the tax benefits plan, 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. On March 16, 2010, our board of directors adopted a tax benefits preservation plan designed to preserve our substantial tax assets. In addition, the plan is intended to act as a deterrent to any person or group acquiring 4.9% or more of our outstanding common stock without our approval.

An active market may not continue for our common stock and we could face de-listing if our stock price declines.

Our common stock is quoted on The NASDAQ Stock Market. While there are currently three market makers in our common stock, these market makers are not obligated to continue to make a market in our common stock. In this event, the liquidity of our common stock could be adversely impacted and a stockholder could have difficulty obtaining accurate stock quotes. If our stock price declines and remains below $1.00 per share for an extended period of time, we could be de-listed from The NASDAQ Stock Market as the minimum threshold for a continued listing is $1.00 per share.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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, 2009. There are no material lease expirations in 2010.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage (1)		Total Net Acres (2)
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	
Rocky Mountain	62,649	32,237	86,551	57,005	1,120	1,120	90,362
Mid-Continent	84,961	21,715	1,957	988	-	-	22,703
Permian Basin	24,494	17,397	15,025	13,395	12,007	5,272	36,064
Gulf Coast	11,210	6,200	7,651	5,214	-	-	11,414
Total	183,314	77,549	111,184	76,602	13,127	6,392	160,543

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

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

Productive Wells

The following table sets forth our total gross and net productive wells, expressed separately for oil and gas, as of December 31, 2009:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Rocky Mountain	390.0	92.8	510.0	17.1
Mid-Continent	124.0	13.5	493.0	75.6
Permian Basin	177.0	129.6	60.0	28.2
Gulf Coast	34.5	25.8	39.5	21.9
Total	725.5	261.7	1,102.5	142.8

Reserves Information

In December 2009, we adopted revised oil and gas reserve estimation and disclosure requirements which conforms the definition of proved reserves with the Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. The new accounting standard requires that the average, first-day-of-the-month price during the 12-month period preceding the end of the year, rather than the year-end price, be used when estimating reserve quantities and permits the use of reliable technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Prior-year data are presented in accordance with Financial Accounting Standards Board ("FASB") oil and gas disclosure requirements effective during those periods.

Oil and gas reserves have been estimated as of December 31, 2007 for all of our properties by DeGolyer and MacNaughton, of Dallas, Texas. DeGolyer and MacNaughton estimated reserves for properties comprising approximately 92% and 95% of the PV-10 of our oil and gas reserves as of December 31, 2008 and December 31, 2009, respectively. Reserves for the remaining 8% and 5% of our properties were estimated by Abraxas 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 as of December 31, 2009 included a total of 402 properties, which comprised approximately 95% of the PV-10 of all our properties as of that date. A total of 867 properties were included in the reserve estimates prepared by Abraxas personnel which comprised approximately 5% of our PV-10 at December 31, 2009. DeGolyer and MacNaughton's reserve report as of December 31, 2008 included a total of 412 properties, which comprised approximately 92% of the PV-10 of all our properties as of that date. A total of 889 properties were included in the reserve estimates prepared by Abraxas personnel which comprised approximately 8% of our PV-10 at December 31, 2008.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. DeGolyer and MacNaughton's opinions indicate that the estimates of proved reserves prepared by us for the properties reviewed by DeGolyer and MacNaughton, when compared in total do not differ materially from the estimates prepared by DeGolyer and MacNaughton. All reports by DeGolyer and MacNaughton were developed utilizing geological and engineering data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 26, 2010, which contains further discussions of the reserve estimates and evaluations prepared by DeGolyer and MacNaughton as well as the qualifications of DeGolyer and MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of proved reserves at December 31, 2009, 2008 and 2007 were based on studies performed by the operations department of Abraxas. The operations department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Operations is the manager of this department and is the primary technical person responsible for this process. The Vice President of Operations holds a Bachelor of Science degree in Petroleum Engineering, and has 25 years of experience in reserve evaluations. The operations department consists of four petroleum engineers with Bachelor degrees in Petroleum Engineering, one of whom is a Registered Professional Engineer in the State of Texas, and various other technical professionals.

Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages are obtained from other departments within the Company.

Oil and gas reserves, and the estimates of the present value of future net revenues therefrom, were determined based on prices and costs as prescribed by SEC and FASB guidelines. 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. 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 for the years ended December 31, 2007 and 2008. For the year ended December 31, 2009, commodity prices over the prior 12-month period and year end costs were used in estimating net cash flows.

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2007, December 31, 2008 and December 31, 2009. All of our reserves are located in the United States.

Estimated Proved Reserves

	Proved Developed	Proved Undeveloped	Total Proved	Probable (1)	Possible (1)
As of December 31, 2007					
Oil (MBbls)	2,184	947	3,131		
Gas (MMcf)	33,908	54,095	88,003		
As of December 31, 2008					
Oil (MBbls)	5,563	1,482	7,045		
Gas (MMcf)	48,209	60,207	108,416		
As of December 31, 2009					
Oil (MBbls)	5,891	2,941	8,832	2,086	2,010
Gas (MMcf)	47,861	48,665	96,526	31,740	18,546

1. Disclosure of probable and possible reserves became optional under SEC guidelines for years ended December 31, 2009, accordingly, no probable or possible reserves are included for the years ended December 31, 2007 and 2008.

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 is the current market value of our estimated oil and gas reserves. In accordance with new SEC requirements, the estimated discounted future net cash flows from proved reserves require us to use an average price over the prior 12-month period, rather than the year-end price on December 31, 2009. In prior years, discounted future net cash flows from proved reserves was 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 our 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, 2009, the Company's net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. However, 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 write downs in the future. Based on managements' review of average first-day-of-the-month prices for the twelve months April 2009 through March 2010, we do not anticipate a write down at the end of the first quarter of 2010.

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 used in 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 utilized in the December 31, 2009 report. The average realized sales prices used for purposes of such estimates were $55.05 per Bbl of oil and $3.42 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $138.4 million in the aggregate primarily in the years 2010 through 2014, which are necessary to develop and realize the value of proved 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.

Proved Undeveloped Reserves

At December 31, 2009, we had 11,052 MBbls of proved undeveloped reserves. During 2009 approximately 4,954 MBoes of December 31, 2008 proved undeveloped reserves were re-classified to the probable and possible categories as a result of the reserves having been on our reserve report for more than five years. None of the proved undeveloped reserves at December 31, 2008 were developed and re-classified to developed producing, during 2009.

Reconciliation of Standardized Measure to PV-10

PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. Due to our loss carry-forwards and the tax basis of our properties, there is no impact of income taxes on our PV-10 calculation as a result, there is no difference between the standardized measure of our oil and gas reserves, which is a GAAP financial measure and the PV-10 of our reserves.

The following matrix reflects Abraxas' total proved reserves (MMBoe) and PV10 (in millions) at various price decks:

		Oil Price				
		$ 40.00	$ 50.00	$ 60.00	$ 70.00	$ 80.00
Gas Price	$ 4.00	22.5 $ 62.4	23.7 $ 98.4	24.6 $ 137.0	25.3 $ 177.3	25.8 $ 218.4
	$ 5.00	23.5 $ 109.0	24.6 $ 145.3	25.5 $ 184.1	26.1 $ 224.4	26.6 $ 265.6
	$ 6.00	24.1 $ 156.8	25.2 $ 193.2	26.1 $ 232.2	26.7 $ 272.6	27.1 $ 313.9
	$ 7.00	24.6 $ 205.3	25.6 $ 241.9	26.5 $ 280.9	27.1 $ 321.3	27.5 $ 362.6
	$ 8.00	24.9 $254.3	26.0 $ 290.9	26.8 $ 330.0	27.4 $ 370.5	27.8 $ 411.8

Oil 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, 2009:

	2007	2008	2009
Oil production (Bbls)	196,944	549,887	578,784
Gas production (Mcf)	5,567,668	6,342,934	6,329,216
Total production (MBOE) (1)	1,125	1,607	1,634
Average sales price per Bbl of oil (2)	$ 69.22	$ 92.66	$ 54.14
Average sales price per Mcf of gas (2)	$ 5.98	$ 7.59	$ 3.24
Average sales price per BOE (2)	$ 41.70	$ 61.66	$ 31.73
Average cost of production per BOE produced (3)	$ 10.02	$ 16.57	$ 16.05

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(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.

(2) Before the impact of hedging activities.

(3) Production costs include direct operating costs, ad valorem taxes and production taxes.

Drilling Activities

The following table sets forth our gross and net working interests in exploratory and development wells drilled during the three years ended December 31, 2009:

	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Oil	-	-	-	-	1.0	1.0
Gas	1.0	0.6	1.0	0.6	-	-

Dry holes	1.0	1.0	-	-	-	-
Total	2.0	1.6	1.0	0.6	1.0	1.0
Development						
Productive						
Oil	3.0	2.6	14.0	7.2	2.0	2.0
Gas	1.0	1.0	35.0	2.2	12.0	0.2
Dry holes	-	-	-	-	1.0	1.0
Total	4.0	3.6	49.0	9.4	15.0	3.2

Present Activities

As of March 12, 2010, we had four operated wells and seven non-operated wells in process of drilling and/or completing. The following provides an overview of our present activities by region:

Rocky Mountain:

- In the Bakken/Three Forks oil play in the Williston Basin, Abraxas is in the process of spacing and permitting its first two operated wells in the play. Both wells are located in eastern McKenzie County, North Dakota and will be drilled on 1,280 acre spacing units - one well will target the middle Bakken formation and the other well will target the underlying Three Forks formation. It is anticipated that each well will have horizontal laterals of approximately 9,000 feet and that each well will be completed with 20 or more stages of fracture stimulation. The first well is currently scheduled to spud in June. Abraxas continues to acquire leases in western North Dakota and eastern Montana as it fills out its existing acreage blocks in anticipation of additional operated drilling in the last half of 2010.
- In Divide County, North Dakota, Abraxas participated in what appears to be a successful Three Forks horizontal well for its 10.3% working interest. The well has been plagued with small mechanical issues, which combined with the shortage of oil field services in the area, has delayed completion. To date, the well has been fracture stimulated with 12 stages out of a planned 20. The remaining 8 stages are scheduled for March 18th. In the interim, the well has been flowing significant amounts of oil and gas while cleaning up fluid from the first 12 stages of fracture stimulation.
- In Divide County, North Dakota, Abraxas committed for its 1.9% working interest in another Three Forks horizontal well to be drilled by one of the more active Bakken players.

Mid-Continent:

- In Hemphill County, Texas, Abraxas participated for its 8.3% working interest in a successful Granite Wash horizontal well operated by a large independent active in the play. The well was drilled to a total measured depth of 15,800 feet, including a 5,000 foot lateral, and completed with a 12-stage fracture stimulation. The well has been on production for several weeks and is currently flowing approximately 17.0 MMcf of liquids-rich gas and 500 Bbl of condensate, or 3,333 Boepd. Net to Abraxas' interest, this production rate equates to approximately 200 Boepd plus natural gas liquids. Abraxas owns additional held-by-production acreage in this play.

Permian Basin:

- In Nolan County, Texas, the Spires Ranch 202 #1 tested oil out of the Ellenburger and Caddo formations and a test of the Strawn formation is pending. Despite concerns about formation pressures, the oil recovery and updated 3-D seismic evaluation has provided Abraxas with sufficient encouragement to drill two (2) additional wells in the near future. One vertical well will test the Strawn, Caddo and Ellenburger formations and a second horizontal well will evaluate the Strawn formation. Abraxas owns a 100% working interest in this play.

Gulf Coast:

- In the Eagle Ford shale play of South Texas, Abraxas continues to acquire acreage in geologically specific areas in anticipation of drilling its first Eagle Ford horizontal well later this year.
- In Bee County, Texas, Abraxas drilled the Bradford #1 in the first quarter of 2010 to a total depth of 10,300 feet. Casing has been set in the well to test several zones in the Wilcox formation after encouraging open hole logs and formation tests. Abraxas owns a 40% working interest in this well.
- In San Patricio County, Texas, Abraxas drilled two oil development wells in the first quarter of 2010. The Welder #86 and #87 were each drilled to a total depth of 8,700 feet. While drilling, both wells encountered a number of oil-prone horizons in the Frio formation and completion operations should be finished during the second quarter of 2010. Abraxas owns a 100% working interest in each of these wells.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist 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, 2009, $5.2 million was outstanding on the note. We lease office space in Calgary, Alberta for a monthly rental of $5,600CN. The lease expires on August 31, 2011.

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 12,177 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, 2009, 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. (Removed and Reserved)

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
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	$ 1.50	$ 0.74
	Second Quarter	1.39	0.85
	Third Quarter	1.88	0.86
	Fourth Quarter	2.55	1.55
2010	First Quarter (Through March 12, 2010)	$ 2.50	$ 1.78

Holders

As of March 12, 2010, Abraxas had 76,230,187 shares of common stock outstanding and had approximately 1,211 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 our common stock.

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 Small Cap 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: American Oil & Gas Inc., Endeavour International Corporation., Evolution Petroleum Corp., Gulfport Energy Corp., GMX Resources Inc., Petroleum Development Corporation, PetroQuest Energy Inc., and Warren Resources Inc.

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, 2004, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2005, 2006, 2007, 2008 and 2009.

	Dec. 31, 2004	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2008	Dec. 31, 2009
Small Cap Index	$ 100.00	$ 197.41	$ 224.81	$ 279.59	$ 99.52	$ 138.15
S&P 500	$ 100.00	$ 103.00	$ 117.03	$ 121.16	$ 74.53	$ 92.01
AXAS	$ 100.00	$ 227.59	$ 133.19	$ 166.38	$ 31.03	$ 82.76

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.

	Year Ended December 31,				
	2005	2006	2007	2008	2009
	(Dollars in thousands except per share data)				
Total revenue	$ 49,216(1)	$ 51,077	$ 48,309	$ 100,310	$ 52,750
Net income (loss)	$ 19,117(2)	$ 700	$ 56,702(3)	$ (52,403)(4)	$ (18,780)
Net income - discontinued operations	$ 12,846(2)	$ —	$ —	$ —	$ —
Net income (loss)	$ 6,271(1)	$ 700	$ 56,702	$ (52,403)	$ (18,780)
Net income (loss) per common share – diluted	$ 0.46	$ 0.02	$ 1.19	$ (1.07)	$ (0.34)
Weighted average shares outstanding – diluted (in thousands)	41,164	43,862	47,593	49,005	55,499
Total assets	$ 121,866	$ 116,940	$ 147,119	$ 211,839	$ 176,236
Long-term debt, excluding current maturities	$ 129,527	$ 127,614	$ 45,900	$ 130,835	$ 143,592
Total stockholders’ equity (deficit)	$ (23,701)	$ (22,165)	$ 55,847	$ 4,658	$ (18,363)

(1) Reflects continuing operations only. Discontinued operations in 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 completed its initial public offering resulting in the substantial divestiture of Abraxas’ investment in Grey Wolf.

(2) Includes gain on the sale of foreign subsidiary of $17.3 million net of non-cash tax of $6.1 million.

(3) Includes gain on sale of assets of $59.4 million.

(4) Includes proved property impairment of $116.4 million in 2008.

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

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

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 exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a 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 three 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:

- commodity prices and the effectiveness of our hedging arrangements;

- 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 Arrangements. 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 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 the first half of 2009 there was a significant drop in prices. Prices began to improve during the second half of 2009. 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. For 2009, NYMEX futures price for WTI oil averaged $61.82 and ended 2009 at $79.36 per barrel. NYMEX Henry Hub futures price for gas averaged $3.94 per MMBtu during 2009 and ended the year at $5.81. If commodity prices 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 gas prices remain depressed or oil prices decline significantly, 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 during 2008 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 our oil and gas properties exceeds the PV-10 of our reserves, we must charge the amount of the excess to earnings. As of December 31, 2008, the net capitalized costs of our oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million. These amounts were calculated considering 2008 year-end prices of $44.60 per Bbl of oil and $5.62 per Mcf of gas as adjusted to reflect the expected realized prices for each of our oil and gas reserves compared to the full cost pool. This charge did not impact cash flow from operating activities, but did reduce our stockholder’s equity and earnings. As of December 31, 2009, the net capitalized costs of our oil and gas properties did not exceed the present value of our estimated proved reserves. These amounts were calculated considering 2009 first-day-of-the-month average prices of $61.18 per Bbl of oil and $4.19 per Mcf of gas as adjusted to reflect the expected realized prices for each of our oil and gas reserves compared to the full cost pool. 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.

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 2009, differentials averaged $7.67 per barrel of oil and $0.70 per Mcf of gas compared to $7.07 per barrel of oil and $1.30 per Mcf of gas in 2008 and $3.10 per barrel of oil and $1.00 per Mcf of gas in 2007. We experienced greater oil differentials during 2009 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 Permian Basin and Gulf Coast properties. Approximately 43% of our production during 2009 was from our Rocky Mountain and Mid-Continent 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.

Our credit facility also required us to enter into hedging arrangements for specified volumes, which equate to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% for 2013.

By removing a significant portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our 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 commodity derivative contracts. For example, in 2007, we sustained an unrealized loss of $6.3 million and a realized gain of $1.9 million. In 2008, we incurred a realized loss of $9.3 million and an unrealized gain of $40.5 million. In 2009 we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 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, 2009:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (Mmbtu)	Swap Price
2010	1,158	$ 73.28	11,258	$ 5.73
2011	1,035	76.61	9,580	6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

At December 31, 2009, the aggregate fair market value of our oil and gas derivative contracts was a liability of approximately $14.0 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 93% of the estimated ultimate recovery of our proved developed producing reserves as of December 31, 2009 had been produced. Based on the reserve information set forth in our reserve estimates as of December 31, 2009, our average annual estimated decline rate for net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. 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.

We had capital expenditures during 2009 of $16.5 million. We have a capital budget for 2010 of approximately $30.0 million. The final amount of our capital expenditures for 2010 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, 2007, 2008 and 2009:

	Year Ended December 31,		
	2007	2008	2009
Total production (MBOE)	1,125	1,607	1,634
Average daily production (BOEpd)	3,082	4,391	4,476

Availability of Capital. As described more fully under “Liquidity and Capital Resources” below, our sources of capital going forward will primarily be cash flow from operating activities, funding under our credit facility, cash on hand and proceeds from the sale of properties and is an appropriate opportunity presents itself, sales of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of December 31, 2009, we had $6.5 million of availability under our credit facility.

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. At December 31, 2009, we operated properties accounting for approximately 76% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations (of which 84 were classified as proved undeveloped at December 31, 2009) on our existing leaseholds the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2009, we drilled or participated in 89 gross (33.03 net) wells of which 95.5% 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. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. In addition, approximately 44% of our estimated proved reserves at December 31, 2009 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. At December 31, 2009, we had a total of $146.5 million outstanding under our credit facility and availability of $6.5 million. 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 our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR-based debt. The 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 our fixed rate to 2.95%. The interest rate swap was further amended in November 2009, lowering our fixed rate to 2.55% on the swap, and extending the term through August 12, 2012.

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 excluding the impact of hedging activities.

	Years Ended December 31, (dollars in thousands, except per unit data.)		
	2007	2008	2009
Operating revenue(1):			
Oil sales	$ 13,633	$ 50,954	$ 31,340
Gas sales	33,273	48,130	20,489
Rig and other	1,403	1,226	921
Total operating revenues	$ 48,309	$ 100,310	$ 52,750
Operating income (loss) (2)	$ 15,524	$ (74,017)	$ 177
Oil production (MBbls)	196.9	549.9	578.8
Gas production (MMcf)	5,567.7	6,342.9	6,329.2
Average oil sales price (per Bbl)	$ 69.22	$ 92.66	$ 54.15
Average gas sales price (per Mcf)	$ 5.98	$ 7.59	$ 3.24

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

Comparison of Year Ended December 31, 2009 to Year Ended December 31, 2008

Operating Revenue. During the year ended December 31, 2009, operating revenue from oil and gas sales decreased by $47.3 million from $99.1 million in 2008 to $51.8 million in 2009. The decrease in revenue was due to lower oil and gas prices in 2009 as compared to 2008 which were partially offset by increased production volumes in 2009 as compared to 2008. The decrease in commodity prices had negative impact of $49.8 million while increased production volumes contributed $2.5 million to revenue.

Oil production volumes increased from 549.9 MBbls for the year ended December 31, 2008 to 578.8 MBbls for the same period of 2009, primarily due to production from new wells placed on production during 2009. Gas production volumes decreased from 6,343 MMcf for the year ended December 31, 2008 to 6,329 MMcf for the same period of 2009, primarily due to natural field declines.

Average sales prices in 2009, before realized gain (loss) on derivative contracts were:

- $54.15 per Bbl of oil, and
- $ 3.24 per Mcf of gas.

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.

Lease Operating Expense and Production Taxes. Lease operating expense (LOE), decreased from $26.6 million in 2008 to $26.2 million in 2009 as a result of lower operating costs. LOE per BOE for the year ended December 31, 2009 was $16.05 per BOE compared to $16.57 for the same period of 2008. The decrease in per BOE was attributable to lower lease operating expenses.

G&A Expense. General and administrative expense, or G&A, excluding stock-based compensation increased from $5.7 million in 2008 to $6.5 million in 2009. The increase in G&A expenses in 2009 as compared to 2008 was primarily due to higher professional and consulting fees, as well as increased cost for director fees related to the Merger. G&A expense per BOE was $3.96 for 2009 compared to $3.56 for the same period of 2008. The increase per BOE cost was attributable to the higher G&A during 2009 as compared to 2008.

Stock-based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted. For the years ended December 31, 2009 and 2008, stock-based compensation was approximately $1.2 million and $1.4 million, respectively. The decrease in 2009 as compared to 2008 was due to expenses related to higher valued options granted in prior years that have been fully amortized.

DD&A Expense. Depreciation, depletion and amortization, (DD&A) expense decreased from $23.3 million in 2008 to $17.9 million in 2009. The decrease in DD&A was primarily the result of the producing property impairment in 2008 which reduced our full cost pool. Our DD&A per BOE for 2009 was $10.95 per BOE as compared to $14.53 per BOE in 2008. The decrease on a per BOE basis in 2009 was primarily the result of the book value of our full cost pool being reduced, due the impairment incurred in 2008.

Interest Expense. Interest expense increased to $11.3 million in 2009 compared to $10.5 million for 2008. The increase in interest expense was primarily due to higher interest rates.

Income taxes. For the year ended December 31, 2009 we incurred $1.3 million in federal and state income taxes. The taxes were the result of a tax basis gain on the merger of Abraxas Energy Partners into Abraxas Petroleum. No 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 ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our derivative contracts was a liability of approximately $16.3 million as of December 31, 2009. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2009, we realized a gain on our derivative contracts of $15.3 million, which included a realized gain of $17.9 million on our commodity swaps and a realized loss of $2.6 million on our interest rate swap. For the year-ended December 31, 2009, we incurred an unrealized loss of $27.6 million, which included an unrealized loss of $28.4 million on our commodity swaps and an unrealized gain of $0.8 million on our interest rate swap. For the year ended December 31, 2008, we realized a loss on our derivative contracts of $9.5 million and we incurred an unrealized gain of $37.9 million.

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 could convert their Partnership units into Abraxas common stock, we recognized an expense of $7.4 million, including approximately $293,000 relating to shares converted during the fourth quarter of 2008 and $7.1 million representing the fair value of potential conversions. During 2009, other expense consisted primarily of costs related to the planned initial public offering of the Partnership, which had previously been capitalized.

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. In accordance with new SEC requirements, the cost ceiling represents the present value (discounted at 10%) of net cash flows from sales of future production using average price over the prior 12-month period. 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. These amounts were calculated in accordance with previous SEC rules 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 the full cost pool. As of December 31, 2009, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves.

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. Based on managements' review of average first-day-of-the-month prices for the twelve months April 2009 through March 2010, we do not anticipate a write down at the end of the first quarter of 2010.

Non-Controlling Interest. Non-controlling interest represents the share of the net income (loss) of the Partnership for the period owned by the partners other than Abraxas. Additionally, in accordance with generally accepted accounting principles in effect at the time, when cumulative losses applicable to the non-controlling interest exceed the non-controlling interest equity capital in the entity, such excess and any further losses applicable to the non-controlling interest are charged to the earnings of the controlling interest. If future earnings are recognized by the non-controlling interest, such earnings will then be credited to the controlling 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, losses applicable to the non-controlling interest exceeded the controlling interest equity capital by $9.3 million. As a result, $9.3 million of the non-controlling interest loss in excess of equity was charged to earnings attributable to Abraxas and was reflected as a reduction of the loss applicable to the non-controlling interest.

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 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 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. 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 per BOE for the year ended December 31, 2008 was $16.57 per BOE compared to $10.02 for the same period of 2007. The increase per BOE 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. 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 per BOE was $3.56 for 2008 compared to $4.84 for the same period of 2007. The decrease per BOE was attributable to the higher G&A expense being offset by higher production volumes during 2008 as compared to 2007.

Stock-based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted. For the year ended December 31, 2008 and 2007, stock-based compensation was approximately $1.4 million and $996,000, respectively.

DD&A Expense. 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 per BOE for 2007 was $12.71 per BOE as compared to $14.53 per BOE in 2008. The per BOE increase 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 in 2007. The increase in interest expense was primarily due to the increase in long term debt incurred with the St. Mary acquisition. Long-term 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 ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated unearned value of our derivative contracts was an asset of approximately $39.2 million as of December 31, 2008. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2008, we realized a loss on our derivative contracts of $9.5 million and an unrealized gain of $37.9 million. For the year ended December 31, 2007, we realized a gain on our derivative contracts of $1.9 million and we incurred an unrealized loss of $6.3 million.

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 could convert their Partnership units into Abraxas common stock, we recognized an expense of $7.4 million, including approximately $293,000 relating to shares converted during the fourth quarter of 2008 and $7.1 million representing the fair value of potential conversions.

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, under SEC rules in effect at the time, 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 year, 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 $116.3 million. 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 the full cost pool.

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.

Non-Controlling Interest. Non-controlling interest represents the share of the net income (loss) of the Partnership for the period owned by the partners other than Abraxas. Additionally, in accordance with generally accepted accounting principles in effect at the time, when cumulative losses applicable to the non-controlling interest exceed the non-controlling interest equity capital in the entity, such excess and any further losses applicable to the non-controlling interest are charged to the earnings of the controlling interest. If future earnings are recognized by the non-controlling interest, such earnings will then be credited to the controlling 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, losses applicable to the non-controlling interest exceeded the controlling interest equity capital by $9.3 million and, as a result, $9.3 million of the non-controlling interest loss in excess of equity was charged to earnings and was reflected as a reduction of the loss applicable to the non-controlling interest.

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.

Our principal sources of capital going forward will be cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financings on terms acceptable to us, if at all.

Working Capital (Deficit). At December 31, 2009, our current liabilities of $28.9 million exceeded our current assets of $11.5 million resulting in working capital deficit of $17.4 million. This compares to working capital deficit $26.0 million as of December 31, 2008. Current liabilities as of December 31, 2009 consisted of trade payables of $8.8 million, revenues due third parties of $3.6 million, other accrued liabilities of $1.4 million, current derivative liabilities of $7.0 million and current maturities of long-term debt of $8.1 million.

Capital Expenditures. Capital expenditures in 2007, 2008 and 2009 were $26.9 million, $174.6 million and $16.5 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2009.

	Year Ended December 31,		
	2007	2008	2009
	(dollars in thousands)		
Expenditure category:			
Exploration/Development	$ 16,793	$ 40,564	$ 16,151
Acquisition	10,000	127,671	—
Facilities and other	115	6,351	320
Total	$ 26,908	$ 174,586	$ 16,471

During 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 oil and gas properties. During 2009, capital expenditures were primarily for the development of existing properties. We anticipate making capital expenditures for 2010 of $30.0 million. These anticipated expenditures are subject to adequate cash flow from operations and availability under our credit facility. If these sources of funding do not prove to be sufficient, we may also issue additional shares of equity securities or sell debt securities, although we may not be able to complete any 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, while oil prices improved during the second half of 2009, gas prices remain fairly weak. Should the prices of oil and gas decline and if our costs of operations increase 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 decreases caused by natural field declines and sales of producing properties.

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

	Year Ended December 31,		
	2007	2008	2009
	(dollars in thousands)		
Net cash provided by operating activities	$ 18,332	$ 43,387	$ 44,136
Net cash used in investing activities	(26,908)	(173,944)	(14,096)
Net cash (used in) provided by financing activities	27,469	113,545	(30,103)
Total	$ 18,893	$ (17,012)	$ (63)

Operating activities for the year ended December 31, 2009 provided $44.1 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities and the monetization of our derivative contracts accounted for most of these funds. Financing activities used $30.1 million for the year ended December 31, 2009 which was predominately the reduction of long-term debt. Investing activities used $14.1 million in 2009 for the development of our oil and gas properties.

Operating activities for the year ended December 31, 2008 provided $43.4 million in cash. 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, including proceeds of long-term borrowing in connection with the St. Mary acquisition. Investing activities used $173.9 million in 2008, including $127.7 million for the St. Mary acquisition as well as the development of our oil and gas properties.

Operating activities for the year ended December 31, 2007 provided $18.3 million in cash. 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, including 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. Investing activities used $26.9 million during the year ended December 31, 2007, including $16.9 million for the development of our oil and gas properties and $10 million for the St. Mary property acquisition that was completed in January 2008.

Future Capital Resources. Our principal sources of capital are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all. Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile and declined significantly during the second half of 2008 and continued to decline during the first part of 2009. Oil prices have strengthened during the second half of 2009 and while gas prices have strengthened somewhat, they remain weak. The decline in commodity prices has significantly reduced our cash flow from operations. As the result of the global recession, commodity prices may stay depressed 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. In the future we may continue to sell non-core 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 and the amount that we are able to borrow under our credit facility will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 44% of our total estimated proved reserves at December 31, 2009 were classified as undeveloped.

We could also seek capital through the sale of debt and equity securities. The current state of the equity and debt markets will have a significant impact on our ability to sell debt or equity securities on terms as favorable as those which existed prior to the current crisis.

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

- Long-term debt
- Operating leases for office facilities

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2009.

Contractual Obligations (in thousands)	Total	December 31, 2010	December 31, 2011-2012	December 31, 2013-2014	Thereafter
		Payments due in twelve month periods ending:			
Long-Term Debt (1)	$ 151,733	$ 8,141	$ 138,817	$ 357	$ 4,418
Interest on long-term debt (2)	24,102	8,614	14,752	596	140
Lease obligations (3)	112	67	45	—	—
Total	$ 175,947	$ 16,822	$ 153,614	$ 953	$ 4,558

(1) These amounts represent the balances outstanding under our credit facility. These repayments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.

(3) Lease on office space in Calgary, Alberta, which expires on August 31, 2011.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2009, our reserve for these obligations totaled $10.3 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2009, 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 material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

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, 2009 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 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 debt consisted of the following:

	December 31, 2008	December 31, 2009
Partnership credit facility	$ 125,600	$ —
Partnership subordinated credit agreement	40,000	—
Credit facility – Term portion	—	8,000
Credit facility – Revolving portion	—	138,500
Real estate lien note	5,369	5,233
	170,969	151,733
Less current maturities	(40,134)	(8,141)
	$ 130,835	$ 143,592

Abraxas Senior Secured Credit Facility

On June 27, 2007, Abraxas entered into a senior secured revolving credit facility, which was amended on February 4, 2009, May 13, 2009 and August 7, 2009. This credit facility was refinanced, amended and restated by the credit facility entered into on October 5, 2009.

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, April 30, 2009, May 7, 2009, June 30, 2009 and July 22, 2009, which we refer to as the Partnership Credit Facility. The Partnership Credit Facility was refinanced, amended and restated by the credit facility entered into on October 5, 2009.

Subordinated Credit Agreement

On January 31, 2008, the Partnership entered into a subordinated credit agreement which was amended on January 16, 2009 and further amended on April 30, 2009, May 7, 2009, June 30, 2009, July 22, 2009, August 13, 2009 and August 31, 2009, which we refer to as the Subordinated Credit Agreement. The Subordinated Credit Agreement was refinanced, amended and restated by the credit facility entered into on October 5, 2009.

Credit Facility

On October 5, 2009, in connection with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. In connection with the Merger, we refinanced, amended and restated the Partnership Credit Facility, the Subordinated Credit Agreement and Abraxas' previous credit facility and we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion of the credit facility. As of December 31, 2009, $138.5 million was outstanding under the revolving portion of the credit facility and $8.0 million was outstanding under the term loan portion of the facility.

The revolving portion of the credit facility has a maximum commitment of $300.0 million and availability under the revolving portion of the credit facility will be subject to a borrowing base. The borrowing base under the revolving portion of the credit facility is currently $145.0 million and will be 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 will be 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, will be able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we will be able to request one redetermination during any six-month period between scheduled redeterminations. The lenders will also be able to make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $145.0 million was determined based upon our reserve report dated June 1, 2009. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the revolving portion of the 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 plus, in each case, (b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31 2009, the interest rate on the revolving portion of the credit facility was 5.75%.

We also borrowed $10.0 million under the term loan portion of the credit facility at the closing of the Merger. Outstanding amounts under the term loan portion of the 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 plus, in each case, (b) 4.75%, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 5.75%. At December 31, 2009, the interest rate on the term loan portion of the credit facility was 7.75%. The term loan portion of the credit facility is subject to amortization beginning on January 31, 2010. The first amortization installment of $1.0 million is due on January 31, 2010 and the second amortization installment of $3.0 million is due on March 31, 2010; thereafter, a quarterly amortization installment of $2.0 million is due at the end of each quarter until the term loan is repaid. It is anticipated that the term loan will be repaid on or before December 31, 2010, after which, it may not be redrawn. The term loan portion of the credit facility was paid down to $8.0 million at December 31, 2009 and on January 29, 2010 an additional $3.0 million was paid. The balance of the term portion of the credit facility was $5.0 million as of January 29, 2010.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is October 5, 2012. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries (other than Canadian Abraxas Petroleum Corporation) has guaranteed our 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 our and our subsidiary guarantors' material property and assets.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.50 to 1.00 for the quarter ending September 30, 2009 through the quarter ending September 30, 2010, and not more than 4.00 to 1.00 thereafter. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with or at the request of a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 (which relates to derivative instruments and hedging activities and was previously referred to as SFAS 133) and ASC 410-20 (which relates to asset retirement obligations previously referred to as SFAS 143) and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718 (which relates to stock-based compensation and was previously referred to as SFAS 123R), ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts or upon the termination of any hedge contract minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equate to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

The following table sets forth our derivative contract position as of December 31, 2009:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (Mmbtu)	Swap Price
2010	1,158	$ 73.28	11,258	$ 5.73
2011	1,035	76.61	9,580	6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

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

- incur or guarantee additional indebtedness;
- transfer or sell assets;

- create liens on assets;
- engage in transactions with affiliates other than on an “arm’s-length” basis;
- make any change in the principal nature of our 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.

We were in compliance with all covenants as of December 31, 2009. As of December 31, 2009, the current ratio was 1.29 to 1.00, the interest coverage ratio was 4.75 to 1.00 and the total debt to EBITDAX ratio was 2.32 to 1.00.

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 building to serve as its corporate headquarters. This note was refinanced in November 2008. 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, 2009, $5.2 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, the Partnership entered into derivative contracts, which we sometimes refer to as hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production through December 31, 2012 from its net proved developed producing reserves. On July 29, 2009, the derivative contracts for the periods 2009 through 2011 were monetized for $26.7 million and together with the July 2009 commodity swap settlement of $2.0 million, the Partnership repaid $28.7 million of indebtedness under the Partnership Credit Agreement on July 31, 2009. Simultaneously, the Partnership entered into new commodity swaps on approximately 85% of its estimated oil and gas production from its net proved developed producing reserves through December 31, 2012 and on 70% for the calendar year 2013. As a result of the Merger, all of the Partnership's derivative contracts were assumed by Abraxas.

The following table sets forth our derivative contract position as of December 31, 2009:

	Fixed-Price Swaps			
	Oil		Gas	
Contract Period	Daily Volume (Bbl)	Swap Price	Daily Volume (Mmbtu)	Swap Price
2010	1,158	$ 73.28	11,258	$ 5.73
2011	1,035	76.61	9,580	6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

By removing a significant portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. 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 commodity derivative contracts. For example, in 2007, we sustained an unrealized loss of $6.3 million and a realized gain of $1.9 million and in 2008 we incurred a realized loss of $9.3 million and an unrealized gain of $40.5 million. For the year ended December 31, 2009, we incurred a realized gain of approximately $17.9 million and an unrealized loss of approximately $28.4 million on all of our commodity derivative contracts. If the disparity between our new contract prices and market prices continues, we will sustain realized and unrealized gains or losses on our derivative contracts. While unrealized gains and losses do not impact our cash flow from operations, realized gains and losses do impact our cash flow from operations. In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower. In addition, the borrowings under our new credit facility will bear interest at floating rates. 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

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development of our numerous drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

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

Net Operating Loss Carryforwards

At December 31, 2009, we had, subject to the limitation discussed below, $121.7 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 ASC 740-10. Therefore, we have established a valuation allowance of $91.5 million for deferred tax assets at December 31, 2009.

We account for uncertain tax positions under provisions of ASC 740-10. ASC 740-10 did not have any effect on the Company’s financial position or results of operations as of January 1, 2007 or for the year ended December 31, 2009. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2009, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 1999 through 2009 remain open to examination by the tax jurisdictions to which the Company is subject.

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.

Environmental Regulations

Various foreign, federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs as a result of their effect oil and gas exploration, development and production operations. These laws and regulations could cause us to incur remediation or other corrective action costs in connection with a release of regulated substances, including oil, into the environment. In addition, we have acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under our control, and under environmental laws and regulations, we could be required to remove or remediate wastes disposed of or released by prior owners or operators. We also could incur costs related to the clean-up of sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such sites. In addition, we could be responsible under environmental laws and regulations for oil and gas properties in which we own an interest but are not the operator. Moreover, we are subject to the United States Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions.

Compliance with such laws and regulations increases our overall cost of business, but has not had, to date, a material adverse effect on our operations, financial condition, results of operations or competitive position. It is not anticipated, based on current laws and regulations, that we will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to our total exploration and development expenditure program in order to comply with such laws and regulations, but, inasmuch as such laws and regulations are frequently changed, we are unable to predict the ultimate cost of compliance or the effect on our operations, financial condition, results of operations and competitive position.

We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, we are also aware of legislation proposed by United States lawmakers to reduce GHG emissions. We are unable to predict the timing, scope and effect of any such proposed laws, regulations and treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations, financial condition and competitive position.

We believe that our strategy to reduce GHG emissions throughout our operations is in the best interest of the environment and a generally good business practice. We will continue to review the risks to our business and operations associated with all environmental matters, including climate change. In addition, we will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary.

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 but 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 2008. 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. 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 was 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. For the year ended December 31, 2009, oil and gas prices were based on the average 12-month first-day-of-the-month pricing as compared to end of period prices in prior years. 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 account for derivative 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 ASC 815; therefore, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. 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, 2008 and 2009, the net market value of our oil and gas derivatives was a net asset of $39.2 million and a liability of $14.0 million, respectively. The market value of our interest rate derivative was a liability of $3.0 million and $2.3 million at December 31, 2008 and 2009, respectively.

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. 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. For the years ended December 31, 2007, 2008 and 2009, stock based compensation was approximately $996,000, $1.4 million and $1.2 million, respectively.

Recent Accounting Pronouncements

In December 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.

- 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.

In December 2009, we adopted revised oil and gas reserve estimation and disclosure requirements which conforms the definition of proved reserves with the SEC Modernization of Oil and Gas Reporting rules which were issued by the SEC. The use of 12-month average prices, as opposed to year end prices, in calculating the present value of our reserves, resulted in a reduction of the standardized measure of discounted future net cash flows of approximately $139.3 million and 1,973.8 MBOE at December 31, 2009. Additionally, the change resulted in a $335,000 increase in DD&A expense in the fourth quarter of 2009.

In August 2009, the FASB issued Accounting Standards Update (ASU) No. 2009-05, Fair Value Measurements and Disclosures (ASU 2009-05). ASU 2009-05 amends Subtopic 820-10, Fair Value Measurements and Disclosures, to provide guidance on the fair value measurement of liabilities. ASU 2009-05 provides clarification for circumstances in which a quoted price in an active market for the identical liability is not available. ASU 2009-05 is effective for interim and annual periods beginning after August 26, 2009. The Company adopted the provisions of ASU 2009-05 for the period ended December 31, 2009. There was no impact on the Company's operating results, financial position or cash flows.

In June 2009, the FASB issued ASU No. 2009-01, Generally Accepted Accounting Principles (ASU 2009-01). ASU 2009-01 establishes "The FASB Accounting Standards Codification," or Codification, which became the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. On the effective date, the Codification superseded all then-existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the Codification will become nonauthoritative. ASU 2009-01 is effective for interim and annual periods ending after September 15, 2009. The Company adopted the provisions of ASU 2009-01 for the period ended September 30, 2009. There was no impact on the Company's operating results, financial position or cash flows.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (ASC 855) to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC 855 is effective for interim and annual reporting periods ending after June 15, 2009. The Company adopted the provisions of ASC 855 for the period ended June 30, 2009. In February

2010, the FASB issued Accounting Standards Update No. 2010-09 ("ASC Update 2010-09"), an update to ASC Topic 855. Among other provisions, this update provides that an entity that is a SEC filer is not required to disclose the date through which subsequent events have been evaluated. We adopted the provisions of ASC Update 2010-09 on its effective date of February 24, 2010. There was no impact on the Company's operating results, financial position or cash flows.

In April 2009, the FASB issued FASB Staff Position (FSP) No. FAS 107-1 and Accounting Principles Board (APB) 28-1, Interim Disclosures about Fair Value of Financial Instruments (ASC 825-10-65) to change the reporting requirements on certain fair value disclosures of financial instruments to include interim reporting periods. The Company adopted ASC 825-10-65 in the second quarter of 2009. There was no impact on the Company's operating results, financial position or cash flows; however additional disclosures were added to the accompanying notes to the consolidated financial statements for the Company's fair value of financial instruments. See Note 13 "Financial Instruments" for more details.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, (ASC 320-10-65), to expand other-than-temporary impairment guidance. There was no impact on the Company's operating results, financial position or cash flows.

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurement using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance is effective for interim and annual periods beginning after December 15, 2010. This guidance provides only disclosure requirements, the adoption of this standard will not impact our results of operations, cash flows or financial position.

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 profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of 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, 2009, a 10% decline in oil and gas, prices would have reduced our operating revenue and cash flow by approximately $5.2 million for the year, however, due to the derivative contracts that we have in place, it is unlikely that a 10% decline in commodity prices from their current levels would significantly impact our operating revenue, cash flow and net income.

Derivative Instrument Sensitivity

We account for our derivative instruments in accordance with ASC 815, all derivative instruments are recorded on the balance sheet at fair value. In 2003, we elected not to designate our derivative instruments as hedges. Accordingly the instruments are recorded on the balance sheet at fair value with changes in the market value of the derivatives being recorded in current derivative income (loss).

On July 29, 2009, our commodity based derivative contracts for the periods 2009 through 2011 were monetized for $26.7 million. These funds, together with $2.0 million from the July 2009 commodity swap settlement, were used by the Partnership to repay $28.7 million of outstanding indebtedness under the Partnership Credit Facility. In connection with the monetization and repayment, the Partnership was required to enter into new commodity swaps. As a result of the Merger, all of the Partnership's derivative contracts were assumed by us.

The following table sets forth our derivative contract position as of December 31, 2009:

	Fixed-Price Swaps			
	Oil		Gas	
Contract Period	Daily Volume (Bbl)	Swap Price	Daily Volume (Mmbtu)	Swap Price
2010	1,158	$ 73.28	11,258	$ 5.73
2011	1,035	76.61	9,580	6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

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 two-year interest rate swap arrangement for $100 million at a fixed rate of 3.367% expires on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 1012.

At December 31, 2009, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $14.0 million and the aggregate fair market value of our interest rate swap was a liability of approximately $2.3 million.

For the year ended December 31, 2009 we recognized a realized gain of $17.9 million and an unrealized loss of $28.4 million on our commodity derivative contracts and we recognized a realized loss of $2.6 million and an unrealized gain of $757,000 on our interest rate swap.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of December 31, 2009, we have $146.5 million of outstanding indebtedness under our credit facility. Outstanding amounts ($138.5 million) under the revolving portion of the 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 plus, in each case, (b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2009, the interest rate on the revolving portion of the credit facility was 5.75%. Outstanding amounts ($8.0 million) under the term loan portion of the 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 plus, in each case, (b) 4.75%, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 5.75%. At December 31, 2009, the interest rate on the term loan portion of the credit facility was 7.75%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.5 million 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 two-year interest rate swap arrangement for $100 million at a fixed rate of 3.367% expires on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

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(T). 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, 2009 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, 2009.

This annual report does not include an attestation of our registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to audit by our independent registered public accounting firm pursuant to rules of the SEC that permit us to provide only management’s report.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

A special meeting of stockholders was held on October 5, 2009.

The stockholders voted on three proposals at the special meeting. These proposals are summarized below and are described more fully in our proxy statement dated September 8, 2009, as filed with the Securities and Exchange Commission.

- Proposal One: To approve the issuance of shares of Abraxas Petroleum common stock in connection with the transaction contemplated by the Amended and Restated Agreement and Plan of Merger dated as of July 17, 2009 by and among Abraxas Petroleum , Abraxas Energy and Merger Sub, as such agreement may be amended from time to time,

- Proposal Two: If Proposal One is approved, to approve an amendment to the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (the "LTIP") to increase the number of shares of Abraxas Petroleum common stock reserved for issuance under the LTIP; and

- Proposal Three: To approve the adjournment of the special meeting, if necessary or appropriate, to solicit additional proxies in the event that there are not sufficient votes at the time of the special meeting to approve the foregoing proposals.

The approval of the proposals required the affirmative vote of a majority of the total votes cast. Stockholders approved all of the proposals by the requisite votes necessary, as indicated below. The number of votes cast for or against and the number of abstentions with respect to each proposal is set forth below. Broker non-votes were not included as votes cast.

	For	Against	Abstain
Proposal One	21,229,237	453,391	115,969
Proposal Two	18,026,538	2,702,060	1,070,000
Proposal Three	20,483,779	1,109,887	204,391

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 2010 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, Paul A. Powell and Brian L. Melton. 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 2009.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2010 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 2010 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 2010 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 2010 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services."

PART IV

Item 14. 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).
3.7	Certificate of Designation of Series 2010 Junior Participating Preferred Stock (Previously filed as Exhibity3.1 to Abraxas Current Report on Form 8-K (filed March 17, 2010.

4.1 Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).

4.2 Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to our Annual Report on Form 10-K filed on March 31, 1995).

4.3 Rights Agreement, dated March 17, 2010 by and between Abraxas and American Stock Transfer and Trust Company (filed as Exhibit 4.1 to Abraxas Registration Statement of Form 8-A filed on March 17, 2010.

*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 Annex E to Abraxas’ Proxy Statement filed on September 8, 2009)).

*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 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).

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

10.16 Voting, Registration Rights and Lock-Up Agreement, dated as of June 30, 2009, by and among Abraxas Petroleum, Abraxas Energy and certain limited partners of Abraxas Energy (Filed as Exhibit 10.1 to Abraxas’ Current Report on Form 8-K filed on July 2, 2009).

10.17 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).

10.18 Amended and Restated Credit Agreement dated as of October 5, 2009 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale as Administrative Agent and as Issuing Lender (Filed as Exhibit 10.1 to Abraxas’ Current Report on Form 8-K filed on October 7, 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 herewith).

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

23.2 Consent of DeGolyer and MacNaughton. (Filed herewith).

31.1 Certification – Chief Executive Officer. (Filed herewith).

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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).
99.1	Report of DeGolyer and MacNaughton (filed herewith).
*	Management Compensatory Plan or Agreement.

Exhibit Index

21.1	Subsidiaries of Abraxas Petroleum Corporation (Filed herewith)
23.1	Consent of BDO Seidman, LLP. (Filed herewith).
23.2	Consent of DeGolyer & 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).
99.1	Report of DeGolyer and MacNaughton. (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: March 17, 2010

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	March 17, 2010
/s/ Chris E. Williford Chris E. Williford	Exec. Vice President and Treasurer (Principal Financial and Accounting Officer)	March 17, 2010
/s/ Craig S. Bartlett, Jr. Craig S. Bartlett, Jr.	Director	March 17, 2010
/s/ Franklin A. Burke Franklin A. Burke	Director	March 17, 2010
/s/ Harold D. Carter Harold D. Carter	Director	March 17, 2010
/s/ Ralph F. Cox Ralph F. Cox	Director	March 17, 2010
/s/ Dennis E. Logue Dennis E. Logue	Director	March 17, 2010
/s/ Paul A. Powell Paul A. Powell	Director	March 17, 2010
/s/Brian L. Melton Brian L. Melton	Director	March 17, 2010
/s/Edward P. Russell Edward P. Russell	Director	March 17, 2010

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 ("Abraxas" or the "Company") as of December 31, 2008 and 2009 and the related consolidated statements of operations, stockholders' equity (deficit), cash flows, and other comprehensive income (loss) for each of the three years in the period ended December 31, 2009. 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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, 2008 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Company retrospectively adopted a new accounting pronouncement on January 1, 2009 related to the accounting for non-controlling interests in the consolidated financial statements.

Also, as discussed in Note 1, during 2009 the Company changed its reserve estimates and related disclosures as a result of adopting new oil and natural gas reserve estimation and disclosure requirements.

/s/ BDO Seidman, LLP

Dallas, Texas
March 17, 2010

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2008 (1)	December 31, 2009
	(Dollars in thousands)	
Current assets:		
Cash and cash equivalents	$ 1,924	$ 1,861
Accounts receivable:		
Joint owners	1,740	865
Oil and gas production sales	6,168	7,873
Other	58	31
	7,966	8,769
Derivative asset – current	22,832	325
Other current assets	572	514
Total current assets	33,294	11,469
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	440,712	454,142
Unproved properties excluded from depletion	—	—
Other property and equipment	10,986	11,259
Total	451,698	465,401
Less accumulated depreciation, depletion, and amortization	291,390	309,245
Total property and equipment - net	160,308	156,156
Deferred financing fees, net	1,443	5,804
Derivative asset – long-term	16,394	2,253
Other assets including marketable securities	400	554
Total assets	$ 211,839	$ 176,236

(1) As adjusted for "Noncontrolling Interest in Consolidated Financial Statements" in accordance with ASC 810.

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	December 31, 2008 (1)	December 31, 2009
	(Dollars in thousands)	
Current liabilities:		
Accounts payable	$ 10,748	$ 8,773
Joint interest oil and gas production payable	3,176	3,606
Accrued interest	350	563
Other accrued expenses	1,886	770
Derivative liability – current	3,000	7,047
Current maturities of long-term debt	40,134	8,141
Total current liabilities	59,294	28,900
Long-term debt – less current maturities	130,835	143,592
Derivative liability – long-term	—	11,781
Future site restoration	9,959	10,326
Total liabilities	200,088	194,599
Commitments and contingencies		
Stockholders' Equity (Deficit):		
Abraxas Petroleum stockholders' equity (deficit)		
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 49,622,423 and 76,231,751	496	762
Additional paid-in capital	187,243	182,647
Accumulated deficit	(183,194)	(201,974)
Accumulated other comprehensive income	113	202
Total Abraxas Petroleum stockholders' equity (deficit)	4,658	(18,363)
Non-controlling interest equity	7,093	—
Total stockholders' equity (deficit)	11,751	(18,363)
Total liabilities, non-controlling interest and stockholders' equity (deficit)	$ 211,839	$ 176,236

(2) As adjusted for "Noncontrolling Interest in Consolidated Financial Statements" in accordance with ASC 810.

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2007 (1)	2008 (1)	2009
	(In thousands except per share data)		
Revenues:			
Oil and gas production revenues	$46,906	$99,084	$51,829
Rig revenues	1,396	1,210	914
Other	7	16	7
	48,309	100,310	52,750
Operating costs and expenses:			
Lease operating and production taxes	11,254	26,635	26,224
Depreciation, depletion, and amortization	14,292	23,343	17,886
Impairment	—	116,366	—
Rig operations	801	856	758
General and administrative (including stock-based compensation of $996; $1,404 ; and $1,239, respectively)	6,438	7,127	7,705
	32,785	174,327	52,573
Operating income (loss)	15,524	(74,017)	177
Other (income) expense:			
Interest income	(408)	(187)	(15)
Amortization of deferred financing fees	671	1,028	1,326
Interest expense	8,392	10,496	11,346
Financing fees	—	359	362
Loss (gain) on derivative contracts (unrealized $6,288, $(37,860) and $27,650)	4,363	(28,333)	12,322
Loss on debt extinguishment	6,455	—	—
Gain on sale of assets	(59,439)	—	—
Other	347	8,523	2,071
	(39,619)	(8,114)	27,412
Income (loss) from operations before income tax and non-controlling interest	55,143	(65,903)	(27,235)
Income tax	283	—	1,290
Consolidated net income (loss)	54,860	(65,903)	(28,525)
Less: Net loss attributable to non-controlling interest	1,842	13,500	9,745
Net income (loss) attributable to Abraxas Petroleum	$56,702	$(52,403)	$(18,780)
Net income (loss) attributable to Abraxas Petroleum common stockholders - per common share - basic	$1.22	$(1.07)	$(0.34)
Net income (loss) attributable to Abraxas Petroleum common stockholders - per common share - diluted	$1.19	$(1.07)	$(0.34)

(1) As adjusted for “Noncontrolling Interest in Consolidated Financial Statements” in accordance with ASC 810.

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- in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income(Loss)	Non-Controlling Interest (1)
Balance at December 31, 2006	42,762,466	$ 428	35,552	$ (485)	$ 164,210	$ (187,493)	$ 975	$ —
Net Income	—	—	—	—	—	56,702	—	(1,842)
Issuance of partnership units	—	—	—	—	—	—	—	29,392
Change in unrealized gain (loss) fair value of investments	—	—	—	—	—	—	(473)	—
Stock-based compensation	—	—	—	—	996	—	—	—
Shares issued for compensation	22,960	—	(35,552)	285	(94)	—	—	—
Stock options exercised	208,109	2	—	—	10	—	—	—
Equity issuance, net of offering costs	5,874,678	59	—	—	20,525	—	—	—
Restricted stock issue	152,736	1	—	—	(1)	—	—	—
Partnership distributions	—	—	—	—	—	—	—	(4,053)
Balance at December 31, 2007	49,020,949	490	—	—	185,646	(130,791)	502	23,497
Net Loss	—	—	—	—	—	(52,403)	—	(13,500)
Change in unrealized gain (loss) fair value of investments	—	—	—	—	—	—	(389)	—
Stock-based compensation	—	—	—	—	1,162	—	—	—
Shares issued for compensation	30,655	—	—	—	60	—	—	—
Stock options exercised	141,501	2	—	—	65	—	—	—
Warrants exercised	31,961	—	—	—	—	—	—	—

Conversion of units in Partnership	344,752	3	—	—	290	—	—	—
Restricted stock issued, net of cancellations	52,605	1	—	—	20	—	—	—
Partnership distributions	—	—	—	—	—	—	—	(9,997)
Abraxas shares issuable under exchange rights agreement	—	—	—	—	—	—	—	7,093
Balance at December 31, 2008	49,622,423	496	—	— $	187,243	(183,194)	113	7,093
Net Loss	—	—	—	—	—	(18,780)	—	(9,745)
Change in unrealized gain (loss) fair value of investments	—	—	—	—	—	—	95	—
Foreign currency translation adjustment	—	—	—	—	—	—	(6)	—
Stock-based compensation	—	—	—	—	1,145	—	—	69
Partnership distributions	—	—	—	—	—	—	—	(2,257)
Partnership units issued	—	—	—	—	—	—	—	256
Partnership registration cost transferred to expense	—	—	—	—	—	—	—	1,385
Shares issued for compensation	61,954	1	—	—	77	—	—	—
Stock options exercised	239,002	2	—	—	201	—	—	—
Merger of partnership into Abraxas Petroleum	25,847,532	258	—	—	(6,014)	—	—	3,199
Restricted stock issued, net of cancellations	460,840	5	—	—	(5)	—	—	—
Balance at December 31, 2009	76,231,751	$ 762	— $	—	182,647	$ (201,974)	$ 202	—

(1) As adjusted for "Noncontrolling Interest in Consolidated Financial Statements" in accordance with ASC 810.

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2007 (1)	2008 (1)	2009
		(In thousands)	
Operating Activities			
Net income (loss)	$54,860	$(65,903)	$(28,525)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Gain) loss on sale of partnership interest	(59,439)	—	—
Change in derivative fair value	6,235	(42,304)	25,740
Monetization of derivative contracts	—	—	26,736
Depreciation, depletion, and amortization	14,292	23,343	17,886
Impairment	—	116,366	—
Accretion of future site restoration	127	570	558
Amortization of deferred financing fees	671	1,028	1,326
Stock-based compensation	996	1,404	1,239
Registration fees previously capitalized	—	—	2,210
Loss on disposal of assets	—	—	289
Other non-cash transactions	191	7,446	78
Changes in operating assets and liabilities:			
Accounts receivable	112	(1,838)	(803)
Other assets and liabilities	15	(206)	(7)
Accounts payable	1,063	4,082	(1,545)
Accrued expenses	(791)	(601)	(1,046)
Net cash provided by operations	18,332	43,387	44,136
Investing Activities			
Capital expenditures, including purchases and development of properties	(26,908)	(174,586)	(16,471)
Proceeds from the sale of oil and gas properties	—	642	2,375
Net cash used in investing activities	(26,908)	(173,944)	(14,096)
Financing Activities			
Proceeds from exercise of stock options	22,441	88	203
Proceeds from issuance of partnership equity	100,000	—	—
Cost of common stock and partnership equity issuance	(9,098)	—	—
Transaction costs on exchange of partnership units	—	—	(2,557)
Proceeds from long-term borrowings	46,690	135,084	13,500
Payments on long-term borrowings	(128,404)	(10,015)	(32,736)
Partnership distribution to non-controlling interest	(3,163)	(9,997)	(2,257)
Deferred financing fees	(997)	(1,615)	(5,687)
Other	—	—	(569)
Net cash provided by (used in) financing activities	27,469	113,545	(30,103)
Increase (decrease) in cash	18,893	(17,012)	(63)
Cash at beginning of year	43	18,936	1,924
Cash at end of year	$18,936	$1,924	$1,861

(1) As adjusted for “Noncontrolling Interest in Consolidated Financial Statements” in accordance with ASC 810.

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(CONTINUED)

	Years Ended December 31,		
	2007	2008	2009
		(in thousands)	
Supplemental disclosures of cash flow information:			
Interest paid	$9,494	$9,817	$10,575

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2007	2008	2009
		(In thousands)	
Net income (loss) attributable to Abraxas Petroleum	$56,702	$(52,403)	$(18,780)
Other Comprehensive income (loss):			
Change in unrealized value of investments	(473)	(389)	95
Foreign currency translation adjustment	—	—	(6)
Other comprehensive income (loss)	(473)	(389)	89
Comprehensive income (loss)	$56,229	$(52,792)	$(18,691)

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

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 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.

On June 30, 2009, Abraxas Petroleum and the Partnership signed an Agreement and Plan of Merger, which we refer to as the Original Merger Agreement, pursuant to which the Partnership agreed to merge with and into Abraxas Petroleum with Abraxas Petroleum surviving and on July 17, 2009, Abraxas Petroleum and the Partnership signed an Amended and Restated Agreement and Plan of Merger, which we refer to as the Merger Agreement, pursuant to which the Partnership agreed to merge with and into Abraxas Merger Sub, LLC, which we refer to as Merger Sub, with Merger Sub surviving the merger as a wholly-owned subsidiary of Abraxas Petroleum. We refer to this merger as the Merger. Under the terms of the Merger Agreement, at the effective time of the Merger on October 5, 2009, which we refer to as the Effective Time, each common unit of the Partnership not owned by Abraxas Petroleum and its subsidiaries was converted into the right to receive 4.25 shares of Abraxas Petroleum common stock. We issued a total of 26,174,061 shares of our common stock in the Merger, including 420,552 shares of restricted common stock issued in exchange for restricted units and phantom units of the Partnership under the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan, or LTIP.

The Company consolidates based on the guidance of Accounting Standards Codification ("ASC") 810. ASC 810 establishes accounting and reporting standards for (1) ownership interests in subsidiaries held by others, (2) the amount of consolidated net income attributable to the controlling and non-controlling interests, (3) changes in the controlling ownership interest, (4) the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated and (5) disclosures that clearly identify and distinguish between the interests of the controlling and non-controlling owners. The adoption of ASC 810 resulted in changes to our presentation for non-controlling interests and did not have a material impact on the Company's results of operations and financial condition. Certain prior period balances have been restated to recasted the changes required by ASC 810.

In accordance with generally accepted accounting principles in effect prior to the adoption of ASC 810, which codifies Statement of Financial Accounting Standards ("SFAS") 160, when cumulative losses applicable to the non-controlling interest exceed the non-controlling interest equity capital in the entity, such excess and any further losses applicable to the non-controlling interest were charged to the earnings of the controlling interest. Future earnings were recognized by the non-controlling interest and were credited to the controlling interest (Abraxas) to the extent of such losses previously absorbed. For the year ended December 31, 2008, primarily due to the ceiling test impairment of the Partnership's oil and gas properties, losses applicable to the non-controlling interest exceeded the non-controlling equity capital by $9.3 million. As a result, $9.3 million of the non-controlling interest loss in excess of equity was charged to earnings attbibutable to Abraxas and was reflected on the income statement as a reduction of the loss applicable to the non-controlling interest.

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 were consolidated for financial reporting purposes. The interest of the 51.8% owners of the Partnership was presented as non-controlling interest (through the date of its merger into Abraxas Petroleum). Abraxas owned the remaining 48.2% of Partnership interests. The Company determined that based on its control of the general partner of the Partnership, this 48.2% owned entity should be consolidated for financial reporting purposes.

Liquidity

The current global recession has had a significant impact on our operations. As a result of the global recession, gas prices are depressed and may stay depressed or reduce further, thereby causing a prolonged downturn, which could reduce our future cash flows from operations. A significant decline in oil prices from current levels could also reduce our future cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans.

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 commodity 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 counterparties to our commodity derivative contracts are the same financial institutions from which we have outstanding debt, accordingly we believe our exposure to credit risk to these counterparties is currently mitigated in part by this, as well as the current overall financial condition of the counterparties.

The Company maintains any 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 $33,000 and $33,000 at December 31, 2008 and 2009, 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, 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. 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. As of December 31, 2009, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves.

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 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.

In accordance with SEC requirements, beginning December 31, 2009, we based the estimated discounted future net cash flows from proved reserves on the unweighted arithmetic average of the prior 12-month commodity prices as of the first day of each of the months constituting the period and costs on the date of the estimate. In prior years, such estimates had been based on year end prices and costs. Future prices and costs may be materially higher or lower than these prices and costs 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.

The adoption of the new guidance in 2009 resulted in a downward adjustment of $139.9 million to the estimated discounted future cash flows from proved reserves and a reduction of 1,973.8 MBOE of proved reserves. Additionally, the change resulted in an increase of $335,000 in DD&A expense in the fourth quarter of 2009.

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.

The Company accounts for derivative 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 ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period.

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 vesting period. 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. For the years ended December 31, 2007, 2008 and 2009, share based compensation was approximately $996,000, $1.4 million and $1.2 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.

The Company accounts for asset retirement obligations based on the guidance of ASC 410 (formerly FASB 143) which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. ASC 410 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:

	2007	2008	2009
		(in thousands)	
Beginning asset retirement obligation	$1,019	$1,183	$9,959
New wells placed on production and other	43	9,046	91
Deletions related to property disposals and plugging costs	(6)	(840)	(282)
Accretion expense	127	570	558
Ending asset retirement obligation	$1,183	$9,959	$10,326

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, 2008 and 2009.

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

During 2007, 2008 and 2009, two purchasers accounted for 25% and 23%; 14% and 15%; and 11% and 11% 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

ASC 220 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 investments and foreign currency translation adjustments.

Accounting for Uncertainty in Income Taxes

ASC 740 provides guidance on accounting for uncertainty in income taxes. ASC 740 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. ASC 740 also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Under ASC 740, 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. Penalties and interest are classified as income tax expense.

The adoption of this standard at January 1, 2007 did not have an impact on the Company's financial position.

New Accounting Pronouncements

On December 29, 2008, the Securities and Exchange Commission adopted rule changes to modernize its oil and gas reporting disclosures "Modernization of Oil and Gas Reporting" (the Final Rule). 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.

- 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.

In January 2010 the FASB issued ASU 2010-03, Extractive Activities – Oil and Gas (Topic 932) Oil and Gas Reserve Estimation and Disclosures ("ASU 2010-03") which aligns the oil and gas reserve estimation and disclosure requirements of ASC 932 with the requirements in the SEC's Final Rule, discussed above. We adopted the Final Rule and ASU effective December 31, 2009.

In December 2009, we adopted revised oil and gas reserve estimation and disclosure requirements which conforms the definition of proved reserves with the SEC Modernization of Oil and Gas Reporting rules, which were issued by the SEC. The use of 12-month average prices, as opposed to year end prices, in calculating the present value of our reserves, resulted in a reduction of the standardized measure of discounted future net cash flows of approximately $139.3 million at December 31, 2009 as well as the standardized measure of discounted future cash flow relating to proved reserves presented in Note 15. The use of average prices affected our depletion calculation for the fourth quarter of 2009 resulting in an increase in DD&A expense of approximately $335,000.

In August 2009, the FASB issued Accounting Standards Update (ASU) No. 2009-05, Fair Value Measurements and Disclosures (ASU 2009-05). ASU 2009-05 amends Subtopic 820-10, Fair Value Measurements and Disclosures, to provide guidance on the fair value measurement of liabilities. ASU 2009-05 provides clarification for circumstances in which a quoted price in an active market for the identical liability is not available. ASU 2009-05 is effective for interim and annual periods beginning after August 26, 2009. The Company adopted the provisions of ASU 2009-05 for the period ended December 31, 2009. There was no impact on the Company's operating results, financial position or cash flows.

In June 2009, the FASB issued ASU No. 2009-01, Generally Accepted Accounting Principles (ASU 2009-01). ASU 2009-01 establishes "The FASB Accounting Standards Codification," or Codification, which became the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. On the effective date, the Codification superseded all then-existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the Codification will become nonauthoritative. ASU 2009-01 is effective for interim and annual periods ending after September 15, 2009. The Company adopted the provisions of ASU 2009-01 for the period ended September 30, 2009. There was no impact on the Company's operating results, financial position or cash flows.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (ASC 855) to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC 855 is effective for interim and annual reporting periods ending after June 15, 2009. The Company adopted the provisions of ASC 855 for the period ended June 30, 2009. In February 2010, the FASB issued Accounting Standards Update No. 2010-09 ("ASC Update 2010-09"), an update to ASC Topic 855. Among other provisions, this update provides that an entity that is a SEC filer is not required to disclose the date through which subsequent events have been evaluated. We adopted the provisions of ASC Update 2010-09 on its effective date of February 24, 2010. There was no impact on the Company's operating results, financial position or cash flows.

In April 2009, the FASB issued FASB Staff Position (FSP) No. FAS 107-1 and Accounting Principles Board (APB) 28-1, Interim Disclosures about Fair Value of Financial Instruments (ASC 825-10-65) to change the reporting requirements on certain fair value disclosures of financial instruments to include interim reporting periods. The Company adopted ASC 825-10-65 in the second quarter of 2009. There was no impact on the Company's operating results, financial position or cash flows; however additional disclosures were added to the accompanying notes to the consolidated financial statements for the Company's fair value of financial instruments. See Note 13 "Financial Instruments" for more details.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, (ASC 320-10-65), to expand other-than-temporary impairment guidance.

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurement using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance is effective for interim and annual periods beginning after December 15, 2010. This guidance provides only disclosure requirements, the adoption of this standard will not impact our results of operations, cash flows or financial position.

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 ASC 280 “Segment Reporting.”

2. Partnership Formation and Merger

Formation

On May 25, 2007, Abraxas 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 the Partnership 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, the Partnership sold 6,002,408 common units, representing an approximate 52.8% interest in the Partnership, 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 Abraxas 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 Abraxas 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) Abraxas 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.

Merger

On June 30, 2009, Abraxas Petroleum and the Partnership signed an Agreement and Plan of Merger, which we refer to as the Original Merger Agreement, pursuant to which the Partnership agreed to merge with and into Abraxas

Petroleum with Abraxas Petroleum surviving and on July 17, 2009, Abraxas Petroleum and the Partnership signed an Amended and Restated Agreement and Plan of Merger, which we refer to as the Merger Agreement, pursuant to which the Partnership agreed to merge with and into Merger Sub with Merger Sub surviving the merger as a wholly-owned subsidiary of Abraxas Petroleum. We refer to this merger as the Merger. Under the terms of the Merger Agreement, at the effective time of the Merger on October 5, 2009, which we refer to as the Effective Time, each common unit of the Partnership not owned by Abraxas Petroleum and its subsidiaries was converted into the right to receive 4.25 shares of Abraxas Petroleum common stock. We issued a total of 26,174,061 shares of our common stock in the Merger, including 420,552 shares of restricted common stock issued in exchange for restricted units and phantom units of the Partnership under the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan, or LTIP.

Simultaneous with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility and we refinanced and amended and restated the Partnership Credit Facility, the Subordinated Credit Agreement and Abraxas' previous credit facility and we borrowed approximately $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion of the credit facility and $10.0 million was borrowed under the term loan portion of the credit facility. See Note 4 Long-Term Debt.

Voting, Registration Rights & Lock-Up Agreement

In connection with the Merger, Abraxas Petroleum agreed within 120 days of the Effective Time, to file a registration statement relating to the resale of the shares of Abraxas Petroleum common stock issued in the Merger, which we refer to as the Registration Statement, pursuant to the Securities Act of 1933, as amended, and to use commercially reasonable efforts to cause the Registration Statement to become effective and to keep the Registration Statement effective until the earlier of (A) January 3, 2013 and (B) the date that all shares of Abraxas Petroleum common stock covered by the prospectus have been sold or otherwise transferred pursuant to a registration statement or otherwise. As a result of Abraxas' obligations in connection with the Merger, Abraxas filed a Registration Statement for the resale of a total of 25,234,467 shares of its common stock on October 19, 2009 and the Securities and Exchange Commission declared the Registration Statement effective on November 3, 2009.

In connection with the Merger, the former limited partners of the Partnership who are party to the Voting, Registration Rights & Lock-Up Agreement (who beneficially own a total of 24,796,879 of the 26,174,061 shares of Abraxas Petroleum common stock issued in the Merger) agreed not to offer for sale, sell, pledge, or otherwise dispose of the Abraxas Petroleum common stock received in the Merger for the 90-day period immediately following the Effective Time, which we refer to as the Lock-Up Period. Upon the expiration of the Lock-Up Period, one-third of the Abraxas Petroleum common stock held by these former Partnership unitholders will be unrestricted and freely-tradable, subject to applicable securities laws. From and after the date which is 12 months after the end of the Lock-Up Period, an additional one-third (or a total of two-thirds) of the Abraxas Petroleum common stock held by these former Partnership unitholders will become unrestricted and freely-tradable and after the expiration of a total of 24 months following the end of the Lock-Up Period, all remaining shares of the Abraxas Petroleum common stock held by these former Partnership unitholders will become unrestricted and freely-tradable.

3. Acquisitions

On January 31, 2008, Abraxas Operating, LLC, a then 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 for a purchase price of approximately $126.0 million. The properties are primarily located in the Rocky Mountains and Mid-Continent regions of the United States.

Simultaneously, Abraxas Petroleum announced that it had completed the acquisition of certain oil and gas properties from St. Mary for a purchase price of approximately $5.6 million. Abraxas paid the purchase price from 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
	(in thousands)	
Revenue	$ 87,643	$ 104,262
Net income (loss)	$ 58,242	$ (50,281)
Earnings (loss) per share – basic	$ 1.26	$ (1.02)

4. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2008 and 2009, respectively:

	December 31, 2008	December 31, 2009
	(in thousands)	
Partnership credit facility	$ 125,600	$ —
Partnership subordinated credit agreement	40,000	—
Senior secured credit facility – Term portion	—	8,000
Senior secured credit facility – Revolving portion	—	138,500
Real estate lien note	5,369	5,233
	170,969	151,733
Less current maturities	(40,134)	(8,141)
	$ 130,835	$ 143,592

Maturities of long-term debt are as follows:

Year ended December 31, (in thousands)	
2010	$8,141
2011	152
2012	138,665
2013	173
2014	184
Thereafter	4,418
	$151,733

Abraxas Senior Secured Credit Facility

On June 27, 2007, Abraxas entered into a senior secured revolving credit facility, which was amended on February 4, 2009, May 13, 2009 and August 7, 2009. This credit facility was refinanced, amended and restated by the credit facility entered into on October 5, 2009.

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, April 30, 2009, May 7, 2009, June 30, 2009 and July 22, 2009, which we refer to as the Partnership Credit Facility. The Partnership Credit Facility was refinanced, amended and restated by the credit facility entered into on October 5, 2009.

Subordinated Credit Agreement

On January 31, 2008, the Partnership entered into a subordinated credit agreement which was amended on January 16, 2009 and further amended on April 30, 2009, May 7, 2009, June 30, 2009, July 22, 2009, August 13, 2009 and August 31, 2009, which we refer to as the Subordinated Credit Agreement. The Subordinated Credit Agreement was refinanced, amended and restated by the credit facility entered into on October 5, 2009.

Credit Facility

On October 5, 2009, in connection with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. In connection with the Merger, we refinanced and amended and restated the Partnership Credit Facility, the Subordinated Credit Agreement and Abraxas' previous credit facility and we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion of the credit facility and $10.0 million was borrowed under the term loan portion of the credit facility. As of December 31, 2009 $138.5 million was outstanding under the revolving portion of the credit facility and $8.0 million was outstanding under the term portion of the credit facility.

The revolving portion of the credit facility has a maximum commitment of $300.0 million and availability under the revolving portion of the credit facility will be subject to a borrowing base. The borrowing base under the revolving portion of the credit facility is currently $145.0 million and will be 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 will be 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, will be able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we will be able to request one redetermination during any six-month period between scheduled redeterminations. The lenders will also be able to make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $145.0 million was determined based upon our reserve report dated June 1, 2009. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the revolving portion of the 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 plus, in each case, (b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2009, the interest rate on the revolving portion of the credit facility was 5.75%.

We also borrowed $10.0 million under the term loan portion of the credit facility at the closing of the Merger. Outstanding amounts under the term loan portion of the 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 plus, in each case, (b) 4.75%, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 5.75%. At December 31, 2009, the interest rate on the term loan portion of the credit facility was 7.75%. The term loan portion of the credit facility is subject to amortization beginning on January 31, 2010. The first amortization installment of $1.0 million is due on January 31, 2010 and the second amortization installment of $3.0 million is due on March 31, 2010; thereafter, a quarterly amortization installment of $2.0 million is due at the end of each quarter until the term loan is repaid. It is anticipated that the term loan will be repaid on or before December 31, 2010, after which, it may not be redrawn. The term loan portion of the credit facility was paid down to $8.0 million at December 31, 2009 and on January 29, 2010 an additional $3.0 million was paid. The balance of the term portion of the credit facility was $5.0 million as of January 29, 2010. As of December 31, 2009 there was $6.5 million available under the credit facility.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is October 5, 2012. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries (other than Canadian Abraxas Petroleum Corporation) has guaranteed our 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 our and our subsidiary guarantors' material property and assets.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.50 to 1.00 for the quarter ending September 30, 2009 through the quarter ending September 30, 2010, and not more than 4.00 to 1.00 thereafter. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with or at the request of a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 (which relates to derivative instruments and hedging activities and was formerly referred to as SFAS 133) and ASC 410-20 (which relates to asset retirement obligations and was formerly referred to as SFAS 143) and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718 (which relates to stock-based compensation and was formerly referred to as SFAS 123R), ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts or upon the termination of any hedge contract minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equate to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

The following table sets forth our derivative contract position as of December 31, 2009:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (Mmbtu)	Swap Price
2010	1,158	$ 73.28	11,258	$ 5.73
2011	1,035	76.61	9,580	6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

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

- incur or guarantee additional indebtedness;
- transfer or sell assets;

- create liens on assets;
- engage in transactions with affiliates other than on an “arm’s-length” basis;
- make any change in the principal nature of our 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.

We were in compliance with all covenants as of December 31, 2009. As of December 31, 2009, the current ratio was 1.29 to 1.00, the interest coverage ratio was 4.75 to 1.00 and the total debt to EBITDAX ratio was 2.32 to 1.00.

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 building to serve as its corporate headquarters. This note was refinanced in November 2008. 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, 2009, $5.2 million was outstanding on the note.

5. Property and Equipment

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

	Estimated Useful Life Years	December 31, 2008	2009
		(In thousands)	
Oil and gas properties	—	$440,712	$454,142
Equipment and other	3-39	10,986	11,259
		$451,698	$465,401

6. 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 2007, 2008 and 2009, risk-free interest rates of 4.63% in 2007, 4.39% in 2008 and 2.48% in 2009; dividend yields of -0-%; volatility factors of the expected market price of the Company's common stock of 55% in 2007, 52% in 2008 and 83% in 2009, determined by daily historical prices as well as other market indicators, and a weighted-average expected life of the option of 7.14 years in 2007, 7.86 years in 2008 and 6.13 in 2009.

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 5.2 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, 2009 follows:

	Options (000s)	Weighted-Average Exercise Price	Weighted Average Remaining Life	Intrinsic value Per Share
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	$ 2.81		
Granted	2,175	1.41		
Exercised	(250)	0.93		
Forfeited/Expired	(225)	2.73		
Options outstanding December 31, 2009	4,090	2.18	7.30	$ 1.59
Exercisable at end of year	1,808		4.69	$ 2.31

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

	2007	2008	2009
Weighted average grant-date fair value of stock options granted (per share)	$ 2.26	$ 2.47	$ 1.01
Total fair value of options vested (000's)	$ 888	$ 1,022	$ 801
Total intrinsic value of options exercised (000's)	$ 256	$ 149	$ 155

As of December 31, 2009, the total compensation cost related to non-vested awards not yet recognized is approximately $2.2 million, which will be recognized in 2010 through 2013.

The following table represents the range of option prices and the weighted average remaining life of outstanding options as of December 31, 2009:

Options outstanding			Exercisable		
Number	Weighted average remaining	Weighted average exercise	Number	Weighted average remaining	Weighted average exercise

	outstanding	life		price	exercisable	life		price
$0.50 – 0.99	1,486,005	6.46	$	0.86	582,705	2.24	$	0.66
$1.00 – 1.99	1,365,035	9.14	$	1.67	155,000	4.26	$	1.16
$2.00 – 2.99	66,857	5.04	$	2.69	66,857	5.04	$	2.69
$3.00 – 3.99	290,994	7.59	$	3.60	142,309	7.58	$	3.60
$4.00 – 4.99	800,001	5.91	$	4.57	800,001	5.91	$	4.56
$5.00 – 6.05	81,000	6.07	$	6.05	60,750	6.07	$	6.05
	4,089,892				1,807,622			

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.

A summary of the Company’s restricted stock activity for the year ended December 31, 2009 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	(41,061)	3.60
Forfeited	(2,959)	3.51
Unvested December 31, 2008	164,280	$3.35
Granted	462,552	1.71
Vested/Released	(74,648)	2.76
Forfeited	(3,276)	2.62
Unvested December 31, 2009	548,908	$2.05

Restricted Unit Awards

Restricted unit awards are awards of Partnership units 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 unit is determined using the implied market price on the grant date. The implied market price is determined by comparing the average trading yields of comparable publicly-traded master limited partnerships to the most recent quarterly distribution paid or declared by the Partnership. Compensation expense is recorded over the applicable restricted unit vesting periods.

For the year ended December 31, 2009, the Partnership incurred equity-based compensation expense of $69,000, relating to restricted units. In connection with the closing of the Merger, restricted unit awards were converted into restricted stock awards of the Company. See Note 2. Recent Events

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 and 2009, the Partnership incurred equity based compensation expense of $242,000 and $25,000 respectively, relating to phantom units. In connection with the closing of the Merger, outstanding phantom unit awards were converted into restricted stock awards of the Company. See Note 2.

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 60,000 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 $20,000 per year, $12,000 of which is paid quarterly by issuance of common stock and the remaining $8,000 is paid quarterly in cash. During 2007, 2008, and 2009 there were 22,960; 30,655; and 61,954 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, 2009, the Company had approximately 2.1 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. No warrants were exercised in 2009.

7. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

	December 31,		
	2007	2008	2009
	(In thousands)		
Deferred tax liabilities:			
Marketable securities	$169	$33	$67
Partnership interest	26,356	18,349	—
Total deferred tax liabilities	26,525	18,382	67
Deferred tax assets:			
U.S. full cost pool	135	418	37,360
Capital loss carryforward	5,010	—	—
Depletion carryforward	5,179	5,189	4,421
Net operating loss (“NOL”) carryforward	60,067	68,034	42,583
Suspended losses	1,400	—	—
Alternative minimum tax credit	100	78	503
Allocated minority loss carryforward	—	3,267	—
Hedge contracts	—	—	3,798
Other	1,805	2,159	2,890
Total deferred tax assets	73,696	79,145	91,555
Valuation allowance for deferred tax assets	(47,171)	(60,763)	(91,488)
Net deferred tax assets	26,525	18,382	67
Net deferred tax	$—	$—	$—

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

	Years ended December 31,		
	2007	2008	2009
	(in thousands)		
Current:			
Federal	$ 100	$ —	$ 425
State	183	—	865
Foreign	-	—	—
	$ 283	$ —	$ 1,290
Deferred:			
Federal	$ —	$ —	$ —
Foreign	—	—	—
	$ —	$ —	$ —

At December 31, 2009, the Company had, subject to the limitation discussed below, $121.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2022 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 $60.8 million at December 31, 2008 and $91.5 million at December 31, 2009.

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

	Years ended December 31,		
	2007	2008	2009
		(In thousands)	
Tax (expense) benefit at U.S. statutory rates (35%)	$(19,945)	$18,341	$6,121
(Increase) Decrease in deferred tax asset valuation allowance	19,701	(13,592)	(30,725)
Expired capital loss carryforward	—	(4,742)	—
State income taxes	(183)	—	(562)
Permanent differences	(5)	(6)	(4)
Increase in asset basis for merger	—	—	23,986
Other	149	(1)	(106)
	$(283)	$—	$(1,290)

We account for uncertain tax positions under provisions of ASC 740-10. ASC 740-10 did not have any effect on the Company's financial position or results of operations as of January 1, 2007 or for the year ended December 31, 2009. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2009, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 1999 through 2008 remain open to examination by the tax jurisdictions to which the Company is subject.

8. Commitments and Contingencies

Operating Leases

During the years ended December 31, 2007 and 2008 the Company incurred rent expense related to leasing office facilities of approximately $254,000 and $321,000. 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, 2009. In September 2009, the Company leased office space in Calgary, Alberta. During 2009, rent expense of $32,300CN was incurred related to this lease.

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, 2009 the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

9. Earnings per Share

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

	Years ended December 31:		
	2007	2008	2009
	(in thousands, except per share data)		
Numerator:			
Income (loss)	$56,702	$(52,403)	$(18,780)
Denominator:			

Denominator for basic earnings per share – weighted-average common shares outstanding	46,337	49,005	55,499
Effect of dilutive securities:			
Stock options, restricted shares and warrants	1,257	—	—

Dilutive potential common shares			
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options, restricted shares and warrants	47,593	49,005	55,499
Net income (loss) per common share – Basic	$1.22	$(1.07)	$(0.34)
Net income (loss) per common share – Diluted	$1.19	$(1.07)	$(0.34)

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 years ended December 31, 2008 and 2009, 334,656 and 310,692 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.

10. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2008 and 2009 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2008				
Net revenue	$ 22,170	$ 34,423	$ 29,246	$ 14,471
Operating income (1)	$ 9,865	$ 19,183	$ 13,925	$ (116,990)
Net income (loss) (2)	$ (8,991)	$ (57,688)	$ 70,755	$ (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)
Year Ended December 31, 2009				
Net revenue	$ 10,850	$ 12,368	$ 13,409	$ 16,123
Operating income (loss)	$ (1,823)	$ 64	$ 557	$ 1,379
Net income (loss)	$ 4,450	$ (10,032)	$ (4,370)	$ (8,828)
Net income (loss) per common share – basic	$ 0.09	$ (0.20)	$ (0.09)	$ (0.12)
Net income (loss) per common share – diluted	$ 0.09	$ (0.20)	$ (0.09)	$ (0.12)

(1) Fourth quarter includes proved property impairment of $116.4 million, $7.1 million of losses not applicable to the non-controlling interest, and a $0.3 million loss on conversion of Partnership units to Abraxas Petroleum common shares.

(2) Third quarter includes gain on sale of interest in partnership of $59.4 million.

11. 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 2007. The Company contribution to the plan for 2007 was $168,977. In 2008 and 2009, in accordance with the safe harbor provisions of the plan the Company contributed $144,954 and $157,436 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 $15,500, $15,500 and $16,500 in 2007, 2008 and 2009 for employees under the age of 50, respectively. The contribution limit for 2007, 2008 and 2009 was $20,500, $20,500 and $22,000 for employees 50 years of age or older, respectively.

12. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. These variations often result in a lack of adequate correlation to enable these derivate instruments to qualify for hedge accounting rules as prescribed by ASC 815. Accordingly, we do not attempt to account for our derivative instruments as cash flow hedges for financial reporting purposes and instead record their fair value on the balance sheet with adjustments to the carrying value of the instruments being recognized as a gain or loss on derivative contracts in the current period.

The terms of the credit facility required us to enter into hedging arrangements for specified volumes, which equate to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

The following table sets forth our derivative contract position as of December 31, 2009:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (Mmbtu)	Swap Price
2010	1,158	$ 73.28	11,258	$ 5.73
2011	1,035	76.61	9,580	6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

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 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 our fixed rate to 2.95%. The interest rate swap was further amended in November 2009, lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

	December 31, 2008		December 31, 2009	
	Balance Sheet Location	Fair Value (thousands)	Balance Sheet Location	Fair Value (thousands)
NYMEX-based fixed price derivative contracts	Derivative asset - current	$22,832	Derivative asset - current	$325
NYMEX-based fixed price derivative contracts	Derivative asset – long-term	$16,394	Derivative asset – long-term	$2,253
NYMEX-based fixed price derivative contracts	Derivative liability - current	$—	Derivative liability - current	$4,791
		$—		$11,780

NYMEX-based fixed price derivative contracts	Derivative liability – long-term		Derivative liability – long-term	
Interest rate swap	Derivative liability - current	$3,000	Derivative liability - current	$2,256

Gains and losses from derivative activities are reflected as “Loss (gain) on derivative contracts” in the accompanying Consolidated Statement of Operations.

13. Financial Instruments

Effective January 1, 2008, the Company adopted ASC 820-10 (formerly 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.

Fair Value on a Non-Recurring Basis

On January 1, 2009, the Company adopted the provisions of ASC 820-10 (formerly SFAS 157) for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. As it relates to Abraxas, the adoption 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.

The adoption of ASC 820-10 did not have material impact on the Company’s consolidated financial statements or its disclosures with respect to the initial recognition of asset retirement obligations during the year ended December 31, 2009. These estimates are derived from historical costs as well as management’s expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Abraxas has designated these liabilities as Level 3.

Fair Value Hierarchy—ASC 820-10 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 tables presents information about the Company’s assets and liabilities measured at fair value on a recurring basis as of December 31, 2008 and 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

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	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

	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, 2009
Assets:				
Investment in common stock	$208	$—	$ —	$208
NYMEX Fixed Price Derivative contracts	—	2,578	—	2,578
Total Assets	$208	$2,578	$ —	$2,786
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$16,571	$ —	$16,571
Interest Rate Swaps	—	—	2,256	2,256
Total Liabilities	$—	$16,571	$ 2,256	$18,827

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, 2009 in US dollars. Accordingly this investment is characterized as Level 1.

The Company'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 Company entered into a two year interest rate swap. The notional amount was $100.0 million for the first year and $50.0 million for the second year. The Company 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%. The interest rate swap was further amended in November 2009 reducing the interest rate to 2.55% and extending the term through August 12, 2012. 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 Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the year ended December 31, 2009 is as follows (in thousands):

	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)
Balance December 31, 2008	(3,000)
Total realized and unrealized losses included in change in net liability	(1,816)
Settlements during the period	2,560
Balance December 31, 2009	$ (2,256)

14. Non-controlling interest in (income) loss of Partnership

The non-controlling interest in the (income) loss of the Partnership represents the third parties 51.8% interest in the Partnership's net income/ loss, through the date of the Merger. In accordance with generally accepted accounting principles in effect prior to the adoption of ASC 810, which codifies SFAS 160, when cumulative losses applicable to the non-controlling interest exceed the non-controlling interest equity capital in the entity, such excess and any further losses applicable to the non-controlling interest were charged to the earnings of the controlling interest. Future earnings were recognized by the non-controlling interest and were credited to the controlling interest (Abraxas) to the extent of such losses previously absorbed. 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 non-controlling interest exceeded the non-controlling equity capital by $9.3 million. As a result, $9.3 million of the non-controlling interest loss in excess of equity was charged to earnings attributable to Abraxas and was reflected as a reduction of the loss applicable to the non-controlling interest.

15. Subsequent Events

Non-Core Divestitures

We have initiated a divestiture program, principally aimed at non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. During the fourth quarter of 2009 and the first quarter of 2010, we have sold certain non-core assets for combined net proceeds of approximately $11.2 million ($2.4 million in 2009 and $8.8 million in 2010). In total, these properties produced approximately 142 Boepd (approximately 3% of our daily net production) and had approximately 606 MBoe of proved reserves (approximately 2% of our net proved reserves), which equates to $78,385 per producing Boepd and $18.41 per proved Boe. The first $10 million of net proceeds will be used to repay the term loan portion of our credit facility after which, any net proceeds will be allocated approximately 50% for further debt reduction and 50% to accelerate our capital program. We have identified an additional $20 to $30 million of similar non-core assets that we will attempt to divest on similar terms over the next several months.

Tax Benefits Preservation Plan

On March 16, 2010, our board of directors adopted a Tax Benefits Preservation Plan (the "Tax Benefits Preservation Plan") and declared a dividend of one preferred share purchase right for each outstanding share of Abraxas common stock. The dividend is payable to our stockholders of record as of March 16, 2010. The terms of the rights and the Tax Benefits Preservation Plan are set forth in a Rights Agreement, by and between us and American Stock Transfer & Trust Company, as Rights Agent, dated as of March 16, 2010.

This summary of rights provides only a general description of the Tax Benefits Preservation Plan.

We adopted the Tax Benefits Preservation Plan in an effort to protect stockholder value by attempting to protect against a possible limitation on our ability to use our net operating loss carryforwards, or NOL's, to reduce potential future federal income tax obligations. We have experienced and continue to experience substantial operating losses, and under the Internal Revenue Code and rules promulgated by the Internal Revenue Service, we may "carry forward" these losses in certain circumstances to offset any current and future earnings and thus reduce our federal income tax liability, subject to certain requirements and restrictions. To the extent that the NOLs do not otherwise become limited, we believe that we will be able to carry forward a significant amount of NOLs, and therefore these NOLs could be a substantial asset to us. However, if we experience an "Ownership Change," as defined in Section 382 of the Internal Revenue Code, our ability to use the NOLs will be substantially limited, and the timing of the usage of the NOLs could be substantially delayed, which could therefore significantly impair the value of that asset. As of December 31, 2009, we had net operating loss carryforwards of $121.7 million.

The Tax Benefits Preservation Plan is intended to act as a deterrent to any person or group acquiring 4.9% or more of our outstanding common stock, or an Acquiring Person, without our approval. Stockholders who own 4.9% or more of our outstanding common stock as of the close of business on March 16, 2010 will not trigger the Tax Benefits Preservation Plan so long as they do not (i) acquire any additional shares of common stock or (ii) fall under 4.9% ownership of common stock and then re−acquire 4.9% or more of the common stock. The Tax Benefits Preservation Plan does not exempt any future acquisitions of common stock by such persons. Any rights held by an Acquiring Person are null and void and may not be exercised. We may, in our sole discretion, exempt any person or group from being deemed an Acquiring Person for purposes of the Tax Benefits Preservation Plan.

The Rights. We authorized the issuance of one right per each outstanding share of our common stock payable to our stockholders of record as of March 16, 2010. Subject to the terms, provisions and conditions of the Tax Benefits Preservation Plan, if the rights become exercisable, each right would initially represent the right to purchase from us one one−thousandth of a share of our Series 2010 Junior Participating Preferred Stock ("Series 2010 Preferred Stock") for a purchase price of $7.00 (the "Purchase Price") . If issued, each fractional share of Series 2010 Junior Preferred Stock would give the stockholder approximately the same dividend, voting and liquidation rights as does one share of our common stock. However, prior to exercise, a right does not give its holder any rights as a stockholder of the Company, including without limitation any dividend, voting or liquidation rights.

Series 2010 Preferred Stock Provisions. Each one one-thousandth of a share of Series 2010 Preferred Stock, if issued: (1) will not be redeemable; (2) will entitle holders to quarterly dividend payments of $0.01 per one one-thousandth of a share of Series 2010 Preferred Stock, or an amount equal to the dividend paid on one share of common stock, whichever is greater, if, as and when declared by our board of directors out of funds legally available therefor; (3) will entitle holders upon liquidation either to receive $1.00 per one one-thousandth of a share of Series 2010 Preferred Stock or an amount equal to the payment made on one share of common stock, whichever is greater; (4) will have the same voting power as one share of common stock; and (5) if shares of our common stock are exchanged via merger, consolidation, or a similar transaction, will entitle holders to a per share payment equal to the payment made on one share of common stock. The value of one one-thousandth interest in a Preferred Share should approximate the value of one share of common stock.

Exercisability. The rights will not be exercisable until the earlier of (i) 10 business days after a public announcement by us that a person or group has become an Acquiring Person or (ii) 10 business days after the commencement of a tender or exchange offer by a person or group for 4.9% of the common stock.

We refer to the date that the rights become exercisable as the "Distribution Date." Until the Distribution Date, our common stock certificates will evidence the rights and will contain a notation to that effect. Any transfer of shares of common stock prior to the Distribution Date will constitute a transfer of the associated rights. After the Distribution Date, the rights may be transferred other than in connection with the transfer of the underlying shares of common stock.

After the Distribution Date, each holder of a right, other than rights beneficially owned by the Acquiring Person (which will thereupon become void), will thereafter have the right to receive upon exercise of a right and payment of the Purchase Price, that number of shares of common stock having a market value at the time of exercise of two times the Purchase Price.

Exchange. After the Distribution Date, we may exchange the rights (other than rights owned by an Acquiring Person, which will have become void), in whole or in part, at an exchange ratio of one share of common stock, or a fractional share of Series 2010 Preferred Stock (or of a share of a similar class or series of the Company's preferred stock having similar rights, preferences and privileges) of equivalent value, per right (subject to adjustment).

Expiration. The rights and the Tax Benefits Preservation Plan will expire on the earliest of (i) March 16 2015, (ii) the time at which the rights are redeemed pursuant to the Rights Agreement, (iii) the time at which the rights are exchanged pursuant to the Rights Agreement, (iv) the repeal of Section 382 of the Code or any successor statute if we determine that the Rights Agreement is no longer necessary for the preservation of NOLs and (v) the beginning of a taxable year of the Company of which we determine that no NOLs may be carried forward.

Redemption. At any time prior to the time an Acquiring Person becomes such, we may redeem the rights in whole, but not in part, at a price of $0.01 per right (the "Redemption Price"). The redemption of the rights may be made effective at such time, on such basis and with such conditions as we in our sole discretion may establish. Immediately upon any redemption of the rights, the right to exercise the rights will terminate and the only right of the holders of rights will be to receive the Redemption Price.

Anti−Dilution Provisions. We may adjust the purchase price of the shares of Series 2010 Preferred Stock, the number of shares Series 2010 Preferred Stock issuable and the number of outstanding rights to prevent dilution that may occur as a result of certain events, including among others, a stock dividend, a stock split or a reclassification of the shares of Series 2010 Preferred Stock or our common stock. No adjustments to the purchase price of less than 1% will be made.

Amendments. Before the Distribution Date, we may amend or supplement the Tax Benefits Preservation Plan without the consent of the holders of the rights. After the Distribution Date, we may amend or supplement the Tax Benefits Preservation Plan only to cure an ambiguity, to alter time period provisions, to correct inconsistent provisions, or to make any additional changes to the Tax Benefits Preservation Plan, but only to the extent that those changes do not impair or adversely affect any rights holder.

The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group who attempts to acquire the Company on terms not approved by us. The rights should not interfere with any merger or other business combination approved by us since we may redeem the rights at $0.01 per right at any time until the date on which a person or group has become an Acquiring Person.

16. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying table presents information concerning the Company's oil and gas producing activities as required by ASC 932-235, "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows:

	December 31,	
	2008	2009
	(In thousands)	
Proved oil and gas properties	$440,712	$454,142
Unproved properties	—	—
Total	440,712	454,142
Accumulated depreciation, depletion, and amortization, and impairment	(287,993)	(305,354)
Net capitalized costs	$152,719	$148,788

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

	Years Ended December 31,		
	2007	2008	2009
		(In thousands)	
Development costs	$16,793	$38,644	$15,356
Exploration costs	—	1,920	795
Acquisition costs	10,000	127,671	—
	$26,793	$168,235	$16,151

The results of operations for oil and gas producing activities for the three years ended December 31, 2007, 2008 and 2009, respectively are as follows:

	Years Ended December 31,		
	2007	2008	2009
		(In thousands)	
Revenues	$46,906	$99,084	$51,829
Production costs	(11,254)	(26,635)	(26,224)
Depreciation, depletion, and amortization	(14,147)	(23,077)	(17,361)
Proved property impairment	—	(116,366)	—
General and administrative	(1,361)	(1,431)	(1,617)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$20,144	$(68,425)	$6,627
Depletion rate per barrel of oil equivalent	$12.58	$14.42	$10.63

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, 2007, 2008, and 2009. 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 predominately 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, the average prior 12-month commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows as of December 31, 2009. However, period end prices and costs were used in estimating reserve volumes and future net cash flows as of December 31, 2008 and 2007.

	Liquid Hydrocarbons (Barrels)	Gas (Mcf)
	(In thousands)	
Proved developed and undeveloped reserves:		
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	3,131	88,003
Revisions of previous estimates	(1,651)	(6,160)
Extensions and discoveries	458	5,862
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	7,045	108,416

Revisions of previous estimates	193	(14,652)
Extensions and discoveries	2,173	9,090
Production	(579)	(6,329)
Balance at December 31, 2009	8,832	96,525

	Liquid Hydrocarbons (Barrels)	Gas (Mcf)
	(In thousands)	
Proved developed reserves:		
December 31, 2007	2,184	33,908
December 31, 2008	5,563	48,209
December 31, 2009	5,891	47,861

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.

Reserve extensions and discoveries which increased significantly during 2009 were primarily attributable to our leasehold in the Williston Basin that we acquired from St. Mary in January 2008 and the robust activity of a number of operators in the Bakken/Three Forks oil shale play in which we have offsetting leasehold. Revisions of previous estimates which increased appreciably during 2009 were primarily due to the re-classification of proved undeveloped reserves to the probable and possible categories as a result of the reserves having been on our reserve report for more than five years.

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

The Company's proved oil and gas reserves have been estimated by the Company with the assistance of an independent petroleum engineering firm (DeGolyer & MacNaughton) as of December 31, 2007, 2008 and 2009. The following information has been prepared in accordance with the Securities and Exchange Commission rules and accounting standards based on year end prices and costs for December 31, 2007 and 2008, and based on the 12-month un-weighted first-day-of-the-month average prices for December 31, 2009 and in accordance with provisions of the Financial Accounting Standards Board's Accounting Standards Update No. 2010-03, "Extractive Activities—Oil and Gas (Topic 932)." This topic requires the standardized measure of discounted future net cash flows as of December 31, 2009, to be based on the average, first-day-of-the-month price beginning with the year ended December 31, 2009. The previous rules required reserve estimates be calculated using last day of the year pricing. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. 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. Because prices used in the calculation are average prices for 2009, the standardized measure could vary significantly from year to year based on the market conditions that occurred.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. DeGolyer and MacNaughton's opinions indicate that the estimates of proved reserves prepared by us for the properties reviewed by DeGolyer and MacNaughton, when compared in total do not differ materially from the estimates prepared by

DeGolyer and MacNaughton. All reports by DeGolyer and MacNaughton were developed utilizing geological and engineering data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 26, 2010, which contains further discussions of the reserve estimates and evaluations prepared by DeGolyer and MacNaughton as well as the qualifications of DeGolyer and MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of proved reserves at December 31, 2009, 2008 and 2007 were based on studies performed by the operations department of Abraxas. The operations department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Operations is the manager of this department and is the primary technical person responsible for this process. The Vice President of Operations holds a Bachelor of Science degree in Petroleum Engineering, and has 25 years of experience in reserve evaluations. The operations department consists of four petroleum engineers with Bachelor degrees in Petroleum Engineering, one of whom is a Registered Professional Engineer in the State of Texas, and various other technical professionals.

The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted 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.

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 our proved oil and gas reserves for the three years ended December 31, 2007, 2008 and 2009.

For comparison purposes, our proved reserves under the previous rules would have been approximately, 26,893.6 MBoe compared to 24,919.8 MMBoe under the new rules and standards.

	Years Ended December 31,		
	2007	2008	2009
		(In thousands)	
Future cash inflows	$830,193	$811,644	$816,436
Future production costs	(235,146)	(312,756)	(332,283)
Future development costs	(111,221)	(134,073)	(138,354)
Future income tax expense	—	—	—
Future net cash flows	483,826	364,815	345,799
Discount	(268,140)	(212,823)	(195,270)
Standardized Measure of discounted future net cash relating to proved reserves	$215,686	$151,992	$150,529

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

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

	Year Ended December 31,		
	2007	2008	2009
		(In thousands)	
Standardized Measure – beginning of year	$156,844	$215,686	$151,992
Sales and transfers of oil and gas produced, net of production costs	(35,652)	(72,449)	(25,605)
Net change in prices and development and production costs from prior year	44,791	(69,094)	(4,883)
Extensions, discoveries, and improved recovery, less related costs	29,834	8,694	22,267
Purchases of minerals in place	—	61,761	—
Sales of minerals in place	—	(366)	—
Revisions of previous quantity estimates	24,033	(16,222)	(13,578)
Change in timing and other	(19,847)	2,414	5,137
Accretion of discount	15,683	21,568	15,199
Standardized Measure, end of year	$215,686	$151,992	$150,529

The standardized measure is based on the following oil and gas prices over the life of the properties as of the following dates:

	Year Ended December 31,		
	2007	2008	2009
Oil (per barrel) (1)	$95.98	$44.60	$61.18
Gas (per MMBtu) (2)	7.48	5.62	4.19
Oil (per barrel) (3)	87.30	41.74	55.05
Gas (per MMBtu) (4)	6.33	4.77	3.42

(1) The quoted oil price is the NYMEX near month future price as of December 31 of the applicable year for the years ended December 31, 2007 and 2008. The quoted oil price for the year ended December 31, 2009 in the 12-month un-weighted average first-day-of-the-month West Texas Intermediate spot price for each month of 2009.

(2) The quoted gas price is the NYMEX near month price as of December 31 of the applicable year for 2007 and 2008. The quoted gas price for the year ended December 31, 2009 is the 12-month un-weighted average first-day-of-the-month Henry Hub spot price for each month of 2009.

(3) The oil price is the realized price at the wellhead as of December 31 of each year after the appropriate differentials have been applied.

(4) The gas price is the realized price at the wellhead as of December 31 of each year after the appropriate differentials have been applied.