ABRAXAS PETROLEUM CORP
Form 10-K
March 15, 2012

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, 2011

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 No x

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes xNo

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). YesxNo

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 xNo

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 x
Non-accelerated filer (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 Nox

As of June 30, 2011, 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 $328,674,470 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 12, 2012, there were 92,261,057 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2012 Annual Meeting of Stockholders to be held on May 4, 2012.	Part III

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FORWARD-LOOKING INFORMATION

We make forward-looking statements throughout this report. 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," "may," "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 report 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 procure services and equipment for our drilling and completion activities;
- the prices we receive for our oil and gas and the effectiveness of our hedging arrangements;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- the availability of capital;
- 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; and
- other factors discussed elsewhere in this report.

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 equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or natural gas liquids.

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.

"Boe" – barrels of oil equivalent.

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“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

“MMBoe” – million barrels of oil equivalent.

“MMBtu” – million British Thermal Units of gas.

“MMcf” – million cubic feet of gas.

“NGL” – natural gas liquids measured in barrels.

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 or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

“Dry well” is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

“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 in another reservoir, or to extend a known reservoir.

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

“Net well” is the sum of fractional ownership working interests in gross wells.

“Productive well” is an exploratory or a development well that is not a dry well.

“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” are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable - from a given date forward, from known reservoirs, and under defined economic conditions, operating methods, and government regulations.

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

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“Proved developed non-producing reserves” are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

“Proved undeveloped reserves” are those quantities of oil and gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

“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 geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

“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, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission (“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 or de-escalation, calculated in accordance with Accounting Standards Codifications (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

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Part I

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, 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," refer to Abraxas Petroleum Corporatio together with its consolidated subsidiaries including Abraxas Energy Partners, L.P. and Raven Drilling, LLC ("Raven Drilling") which is a wholly owned subsidiary that owns a drilling rig. Blue Eagle Energy, LLC ("Blue Eagle") is a joint venture between us and Rock Oil Company, LLC ("Rock Oil") to develop the Eagle Ford shale play in South Texas. As of December 31, 2011, we owned an approximate 34.7% equity interest in Blue Eagle.

Item 1. Business

General

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States and Canada. At December 31, 2011, our estimated net proved reserves were 29.0 MMBoe, (including reserves attributable to our 34.7% equity interest in the proved reserves of Blue Eagle), of which 53% were classified as proved developed, 54% were oil and NGL's and 94% by PV-10 were operated. Our daily net production for the year ended December 31, 2011 was 3,484 Boepd, of which 45% was oil or liquids.

Our oil and gas assets are located in four operating regions in the United States, the Rocky Mountain, Mid-Continent, Permian Basin and onshore Gulf Coast, and in the province of Alberta, Canada. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2011:

	Gross Producing Wells	Average Working Interest		Total Net Acres	Estimated Net Proved Reserves (MBoe)	% Oil/NGL		Net Production (MBoe)
Rocky Mountain	1,041	10.27	%	81,327	10,816.7	87.8	%	401.3
Mid-Continent	148	22.57	%	5,769	800.5	18.3	%	61.7
Permian Basin	221	73.46	%	40,979	6,720.6	42.0	%	443.5
Onshore Gulf Coast (1)	58	92.81	%	7,055	9,765.8	18.8	%	340.5
Total United States	1,468	24.28	%	135,130	28,103.6	54.4	%	1,247.0
Alberta, Canada	4	100.00	%	24,800	920.1	47.8	%	24.7
Total	1,472	24.49	%	159,930	29,023.7	54.2	%	1,271.7

(1) Includes 2,791.3 MBoe of estimated proved reserves attributable to our 34.7% equity interest in Blue Eagle.

Our properties in the Rocky Mountain region are located in the Williston Basin of North Dakota and Montana and in the Green River, Powder River and Unita Basins of Wyoming and Utah. In this region, our wells produce oil and gas from various reservoirs, including the Niobrara, Turner, Bakken and Three Forks formations. Well depths range from 7,000 feet down to 14,000 feet.

Our properties in the Mid-Continent region are primarily located in the Arkoma Basin and principally produce gas from the Hartshorne coals at 3,000 feet.

Our properties in the Permian Basin region are primarily located in two sub-basins, the Delaware Basin and the Eastern Shelf. In the Delaware Basin, our wells are located in Pecos, Reeves, and Ward Counties, Texas and produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet. In the Eastern Shelf, our wells are principally located in Coke, Scurry, Midland, Mitchell and Nolan Counties, Texas and produce oil and gas from the Strawn Reef formation at 5,000 to 7,500 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet.

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Our properties in the onshore Gulf Coast region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas and in the Portilla field in San Patricio County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation at a depth of 14,000 feet and in the Portilla field, our wells produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet. In addition, we also own a 34.7% equity interest in a joint venture targeting the Eagle Ford in South Texas.

Our properties in the province of Alberta, Canada are located in the Pekisko fairway and the Nordegg/Tomahawk area of Central Alberta in addition to an emerging shale play in central Alberta.

Strategy

Our business strategy is to provide long term growth in net asset value per share by increasing daily production and proved reserves over time as well as adding to our inventory of development projects, while maintaining a conservative leverage position to enhance financial flexibility. Key elements of our business strategy include:

Developing our drilling inventory. Through our existing acreage position, we have a multi-year drilling inventory in excess of 300 net potential drilling locations (based on standard industry spacing parameters and management estimates) in our existing properties. We plan to focus our development efforts in 2012 on the oil and liquids-rich Bakken, Three Forks, Eagle Ford, Pekisko and Niobrara formations, as well as our Texas oil plays. We will continue to pursue acreage acquisitions, on a conservative basis, in an effort to increase and enhance our core acreage positions.

Maintaining a mix of operated and non-operated leasehold positions in our resource plays. While developing our resource plays, we plan on maintaining a mix of operated and non-operated interests. As operator, we retain more control over the timing, selection and process of drilling prospects and completion design, which enhances our ability to maximize return on invested capital and gives us greater control over the timing, allocation, and amounts of our capital expenditures. As a non-operated working interest partner, we believe we can leverage our partners' knowledge and experience and potentially reduce our costs and enhance our returns.

Increasing the oil component of our production and proved reserves. By focusing our 2012 drilling activity in the oil and liquids-rich resource plays, we expect to continue to increase the oil/liquids component of both our production and proved reserves. For the year ended December 31, 2011, our mix of oil/liquids and gas production was 45% and 55%, respectively, as compared to our 36% and 64% mix of oil/liquids and gas production for the year ended December 31, 2010. Our proved reserves at December 31, 2011 were 54% oil/liquids and 46% gas.

Maintaining financial flexibility. Our primary sources of capital are availability under our credit facility and cash flow from operations. We plan on deploying our available capital in a cost-effective manner, utilizing pad development drilling, with our own drilling rig in the Williston Basin.

2012 Budget and Drilling Activities

Our capital expenditure budget for 2012 is $70 million, an increase of approximately 17% over 2011. Approximately 75% of the 2012 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region with the remainder targeting conventional oil plays in the Permian Basin region and in the province of Alberta, Canada. The 2012 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

We have a substantial inventory of acreage in several basins, or plays, exposing us to significant resource potential which will be the focus of our development plans in 2012. Our acreage in the unconventional plays includes the Williston Basin focused on the Bakken and Three Forks formations, the onshore Gulf Coast Basin focused on the Eagle Ford Shale, the Powder River Basin focused on the

Niobrara Shale and Turner formation and the Southern Alberta Basin focused on the Bakken formation. Our acreage in the conventional plays includes the Western Alberta Basin focused on the Pekisko formation and several oil plays in Texas focused on the Strawn, Frio and Yates formations. Our net acreage position for each basin or play is detailed in the following table:

Basin/Play	Targeted Formation(s)	Net Acres	
Williston	Bakken / Three Forks	20,835	
Onshore Gulf Coast	Eagle Ford	12,177	(1)
Powder River	Niobrara	17,800	
Western Alberta	Pekisko	6,880	
Southern Alberta	Bakken	10,000	
Texas Oil Plays	Strawn / Frio / Yates	8,700	
Other	Various	83,538	
	Total	159,930	

(1) All of the acreage in the Eagle Ford Shale play is owned by Blue Eagle.

In 2012, we intend to concentrate our activities in the following plays:

Williston Basin - Bakken/Three Forks. We currently lease approximately 20,835 net acres, primarily in counties located on the Nesson Anticline and in areas west including Rough Rider and Lewis & Clark in North Dakota and in Sheridan County, Montana, which are prospective for the Bakken and Three Forks formations. In 2010 and 2011, we drilled two operated wells and participated in an additional 19 gross (1.0 net) non-operated wells.

In July 2011, Abraxas purchased a used Oilwell 2000 hp diesel electric drilling rig in order to help us control the timing and cost of drilling our operated wells. The rig has been refurbished and will be mobilized to the Williston Basin to drill Bakken / Three Forks wells using a multi-well pad drilling system in the near future. Abraxas anticipates that the rig will be ready to spud its first well in late March to early April, 2012 in the North Fork area of McKenzie County, North Dakota where the Company has 60 gross (18 net) identified drilling locations. In 2012, we plan to drill up to ten operated horizontal long lateral wells, utilizing our own drilling rig, and participate in additional non-operated wells targeting the Bakken or Three Forks formations.

Onshore Gulf Coast Basin - Eagle Ford. In August 2010, we formed a joint venture, Blue Eagle, with Rock Oil to develop our acreage in the Eagle Ford Shale play. At formation, we contributed 8,333 net acres, located in Atascosa, DeWitt and Lavaca Counties, Texas, and received a 50% equity interest in Blue Eagle, and Rock Oil contributed $25 million in cash and received a 50% equity interest. Rock Oil also committed to contribute an additional $50 million in cash, of which $22.0 million has been contributed since formation. Upon full funding by Rock Oil, we would own a 25% equity interest and Rock Oil would own a 75% equity interest in Blue Eagle. As of December 31, 2011, we owned a 34.7% interest in Blue Eagle. During 2011, Blue Eagle drilled, completed or participated in 3 gross (2.4 net) wells and added approximately 3,800 net acres to its holdings, principally in McMullen County, Texas., Blue Eagle has announced that it will be exploring all of its strategic alternatives.

Powder River Basin. We currently lease a total of approximately 20,720 gross (17,800 net) acres in the southern Powder River Basin, of which 17,800 gross (15,700 net) acres are located in the Brooks Draw field of Converse and Niobrara Counties, Wyoming. Prior to 2011, we drilled a total of 12 wells, including seven horizontal wells, and acquired a 23-square mile proprietary 3-D seismic survey in the Brooks Draw field. In addition, we own approximately 2,100 net acres in southern Campbell County, Wyoming which are held by production and are near the Crossbow field operated by EOG Resources, Inc. and other recent horizontal activity. In 2012, we have budgeted the drilling of one horizontal well. We may elect to increase our activity in the area pending results of this well.

Alberta Basin - Pekisko. We currently lease 6,880 net acres in western Alberta. In 2011, we drilled or completed 6 gross (6 net) wells in the Twining area, two of which await stimulation and three of which await pipeline hookup. Our budget for 2012 currently includes the drilling of one horizontal well targeting the Pekisko formation, after which we plan to review our strategic alternatives with respect to this area, as we continue to conservatively build an acreage position in an emerging shale play in central Alberta.

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Alberta Basin – Bakken. In the emerging southern Alberta Basin Bakken play of Toole and Glacier Counties, Montana, we currently lease approximately 10,000 gross/net acres under long-term leases or direct mineral ownership. During 2010 and 2011, we acquired our leasehold position and monitored industry activity in the play, principally by Rosetta Resources Inc. and Newfield Exploration Company, and continued our own independent study of the play. During 2012, we intend to continue to conservatively acquire additional acreage in the geologically specific parts of the play.

Permian Basin – Strawn. We currently lease approximately 5,600 gross/net acres in Nolan County, Texas. In 2011, we drilled three wells in the Spires Ranch offsetting the prolific Nena Lucia field. Our budget for 2012 currently includes the drilling of three horizontal wells targeting the Strawn formation.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices we receive for our 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 petroleum producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices we receive for our 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 Hedging Arrangements" and Note 14 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2011, two purchasers accounted for approximately 26% of our oil and gas sales, and a single purchaser accounted for 14% of our oil and gas sales. We believe that there are numerous other purchasers available to buy our oil and gas and that the loss of one or both of these purchasers would not materially affect our ability to sell our 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, provincial 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 periodically changing administrative regulations.

Federal, state, provincial 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, provinces and other local authorities in which we operate properties. In addition, under federal and provincial 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, provincial, 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 provinces, states, and some counties and municipalities in which we operate, regulate one or more of the following:

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

Some provinces and states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some provinces and states allow forced pooling or unitization of tracts to facilitate exploration while other states/provinces 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, provincial and 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 our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each province and state generally imposes a production or severance tax with respect to the production and sale of oil, gas and NGLs within its jurisdiction.

Operations on Federal, Provincial 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 and the Office of Natural Resources Revenue, which we refer to as ONRR, (formerly Minerals Management Service). ONRR establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by ONRR and the state regulatory authorities is generally applicable to all federal and state oil and 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 or provincial leases. The regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect us.

Regulation of Transportation and Sale of Natural Gas in the United States

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

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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 currently 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 natural 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 in the United States

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. 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 in the United States

Sales of 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 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

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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, provincial, 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 penalties 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, provincial, or local environmental protection laws and regulations, or under federal, provincial 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.

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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. On August 23, 2011 EPA proposed new more restrictive regulations governing air emissions from oil and gas operations, including regulations which, if adopted, would impose new restrictions on volatile organic compounds, sulfur dioxide and hazardous air pollutants. The proposed regulations also seek to restrict air emissions arising from hydraulic fracturing operations.

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. Most of our current 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, or other proppants, 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 such as Fracturing Responsibility and Awareness of Chemicals (FRAC) Act have been introduced in Congress to subject hydraulic fracturing to federal regulation under laws such as the Safe Drinking Water Act. If adopted, these bills could result in additional chemical disclosure and permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These 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, these bills would require the public disclosure of 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. EPA has finalized its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, which is expected to result in a final report on the subject with recommendations in 2014. Also, the U.S. Department of the Interior has announced that it intends to propose regulations governing hydraulic fracturing which occurs on federal lands, including requiring chemical disclosure. In addition to these federal legislative and regulatory proposals, some states and local governments have considered imposing, or have adopted and some have adopted 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. These types of conditions are widely adopted, we could be subject to increase costs and possibly limits on the productivity of certain wells. Some states in which we operate have implemented disclosure requirements of chemicals used in hydraulic fracturing.

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. As a result of the Supreme Court decision in Massachusetts, et al. v. EPA, 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, the EPA has 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. These regulations may apply to our operations. The EPA has adopted 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 may affect the cost of our operations and also affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Although various climate change legislative measures have been under consideration by the U.S. Congress, it is not possible at this time to predict whether, or if, Congress will act on climate change legislation, although initiatives such as cap-and-trade legislation, appears to be unlikely to become law in their current form. Finally, some states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular jurisdiction of our operations, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations. 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. We are aware of new efforts to seek to

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cause the U.S. Fish and Wildlife Service to list additional species as endangered or threatened, and those actions or 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 our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface 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 make a thorough title search, 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 and services 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 near term operations; however we cannot assure you that such materials and resources will be available to us in the future.

Employees

As of March 12, 2012, we had 104 full-time employees. We retain independent geological, land and engineering consultants from time to time 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 ("SEC"). 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 SEC 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 web site 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, 2011, we had a total of $115.0 million of indebtedness under our credit facility. Our indebtedness could have important consequences to us, including:

- effecting our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes which may be impaired or not 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 future business 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 indebtedness will make us more vulnerable to competitive pressures if there is a downturn in our business or the economy in general, 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 capital expenditures, acquisitions and/or selling assets, restructuring or refinancing our indebtedness or seeking additional debt or equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of our 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 our credit facility and to accelerate the repayment of amounts outstanding (including accrued and unpaid interest and fees). Upon a default under our 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.

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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 is 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 our credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/or production, an 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 our credit facility is reduced, we could be required to reduce borrowings under our 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 properties sold with production from our 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. Based on the reserve information set forth in our reserve report as of December 31, 2011 (which does not include the reserves of Blue Eagle), our average annual estimated decline rate for our net proved developed producing reserves is 14% 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 43% of our total estimated proved reserves at December 31, 2011 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 adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- the availability and costs of drilling and service equipment and crews;

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- economic and industry conditions at the time of drilling;
- prevailing and anticipated prices for oil and gas;
- the availability of sufficient capital resources;
- the results of our exploitation efforts;
- the acquisition, review and interpretation of seismic data; and
- our ability to obtain permits for drilling locations.

Although we have identified or budgeted for numerous drilling locations, we may not be able to drill those locations within our expected time frame or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties.

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 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 is compounded by the fact that 43% of our total estimated proved reserves as of December 31, 2011 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.

The results of our drilling in unconventional formations, principally in emerging plays with limited drilling and production history using long laterals and modern completion techniques, are subject to more uncertainties than our drilling program in the more established plays and may not meet our expectations for reserves or production.

We drill wells in unconventional formations in several emerging plays. Part of our drilling strategy to maximize recoveries from these formations involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have proven to be successful in other basins. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date, as well as the industry’s drilling and production history in these formations, is relatively limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established. In addition, based on reported decline rates in these emerging plays as well as the industry’s experience in these formations, we estimate that the average monthly rates of production may decline as much as 70% during the first twelve months of production. Actual decline rates may differ significantly. Accordingly, the results of our drilling in these unconventional formations are more uncertain than drilling results in other more established plays with longer reserve and production histories.

Our joint venture agreement with Rock Oil and other agreements that we may enter into present a number of challenges that could have a material adverse effect on our business, financial condition and results of operations.

Our joint venture agreement with Rock Oil represents an important part of our business. In addition, we may enter into other similar arrangements, some of which may be material. These arrangements typically present financial, managerial and operational challenges, including the existence of unknown potential disputes, liabilities or contingencies and may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their share of such obligations;
- our joint venture partners may terminate the agreements;

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- we may incur liabilities as a result of an action taken by our joint venture partners;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint venture or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations.

We cannot control the activities on the properties we do not operate and are unable to ensure their proper operation and profitability.

We currently do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over and control the risks associated with operation of these properties. The failure of an operator to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including:

- the operator could refuse to initiate exploitation or development projects and if we proceed with any of those projects, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploitation or development projects on a different schedule than we would prefer;
- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects and thus, not participate in the associated revenue stream; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploitation and development activities.

Seasonal weather conditions and other factors could adversely affect our ability to conduct drilling activities.

Our operations could be adversely affected by weather conditions and wildlife restrictions on federal leases. In the Williston Basin, Powder River Basin and in Canada, drilling and other oil and gas activities cannot be conducted as effectively during the winter and spring months. Winter and severe weather conditions limit and may temporarily halt the ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our oil and gas operations and materially increase our operating and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, oil field services or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. During times and in areas of increased activity, the demand for oilfield services will also likely rise, and the costs of these services will likely increase, while the quality of these services may suffer. If the lack of availability or high cost of drilling rigs, equipment, supplies, oil field services or qualified personnel were particularly severe in any of our areas of operation, we could be materially and adversely affected. Delays could also have an adverse effect on our results of operations, including the timing of the initiation of production from new wells.

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Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors that are beyond our control.

Our drilling operations are subject to a number of risks, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- adverse weather conditions;
- title problems;
- unusual or unexpected geological formations;
- 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 do not insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and gas operations.

We do not insure against all risks. Our oil and gas exploitation and production activities are subject to hazards and risks associated with drilling for, producing and transporting oil and gas, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, shoreline contamination, underground migration and surface spills or mishandling of fracturing fluids, including chemical additives;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- leaks of gas, oil, condensate, natural gas liquids and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, including hydraulic fracturing, or in the gathering and transportation of hydrocarbons, malfunctions of pipelines, measurement equipment or processing or other facilities in the Company's operations or at delivery points to third parties;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and

- natural disasters.

We might elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations.

Hydraulic fracturing, the process used for extracting oil and gas from shale and other formations, has recently come under increased scrutiny and could be the subject of further regulation that could impact the timing and cost of development.

The Underground Injection Control, or UIC, regulation promulgated under the provisions of the federal Safe Drinking Water Act, or the SDWA, exclude hydraulic fracturing from the definition of "underground injection." However, the Environmental Protection Agency, or EPA, is now re-evaluating hydraulic fracturing and the U.S. Senate and House of Representatives are currently considering bills

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entitled the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the SDWA to repeal this exemption. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities, which could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater.

Hydraulic fracturing is the primary completion method used to extract reserves located in many of the unconventional oil and gas plays in the United States and Canada. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and gas production. We use this completion technique on substantially all of our wells. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal, state and/or provincial levels, exploration, exploitation and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Some states in which we operate, including Texas, have recently implemented disclosure requirements of chemicals used in hydraulic fracturing, and the U.S. Department of the Interior has announced that it intends to propose regulations governing hydraulic fracturing on federal lands, including requiring chemical disclosure. Individually or collectively, such existing and new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business, 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 acceptable of favorable to us. For example, at December 31, 2011, we were not in compliance with the financial ratio that we maintain a current ratio, as of the last day of each quarter of not less than 1.00 to 1.00. 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 a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20, and any accounts receivable from Blue Eagle 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, and any accounts payable to Blue Eagle.

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, as well as Canadian provincial, 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 our access to these transportation options dramatically changes, the financial impact on us could be substantial and adversely affect our ability to produce and market our 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, product quality, 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 2011, differentials averaged ($7.13) per Bbl of oil and ($0.58) per Mcf of gas. Approximately 32% of our production during 2011 was from the Rocky Mountain region. Historically, this region has experienced wider differentials than our Permian Basin and Gulf Coast properties. As the percentage of our production from the Rocky Mountain region increases, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the realized 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, 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 67% of the oil and gas production from our estimated net proved developed producing reserves (as of December 31, 2011) through December 31, 2012 and 59% for 2013. 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 contracts. For example, the prices utilized in our derivative contracts 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 the oil and gas is 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, a significant portion of which is based on the delivery location which is called the basis 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

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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 opportunity 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 conversely, when our contract prices are lower than market prices, we will incur realized and unrealized losses. For the year ended December 31, 2011, we recognized a realized gain on oil and gas derivative contracts of $1.7 million and an unrealized gain of $5.7 million. The realized gains 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.

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 cash payments from the counterparties to our derivative contracts. Any number of factors 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.

Potential regulations under the Dodd-Frank Act regarding derivatives could adversely impact our ability to engage in commodity price risk management activities.

On July 21, 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which imposes a comprehensive regulatory scheme significantly impacting companies engaged in over-the-counter swap transactions. The Dodd-Frank Act generally applies to “swaps” entered into by “major swap participants” and/or “swap dealers,” each as defined in the Dodd-Frank Act. A swap is very broadly defined in the Dodd-Frank Act and includes an energy commodity swap. A swap dealer includes an entity that regularly enters into swaps with counterparties as an “ordinary course of business for its own account.” Furthermore, a person may qualify as a major swap participant if it maintains a “substantial position” in outstanding swaps, other than swaps used for “hedging or mitigating commercial risk” or whose positions create substantial exposure to its counterparties or the U.S. financial system. The Dodd-Frank Act subjects swap dealers and major swap participants to substantial supervision and regulation by the Commodity Futures Trading Commission, or the CFTC, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also requires most regulated swaps to be cleared through a derivatives clearing organization, or DCO, registered with the CFTC. By clearing through a DCO, each party to a swap will be required to provide collateral to the DCO to settle, on a daily basis, any credit exposure resulting from fluctuations in market prices. The CFTC also has the authority to impose position limits on companies trading in OTC derivatives markets. Although the Dodd-Frank Act provides a framework for regulating OTC swap transactions, the substance of the Dodd-Frank Act will be set forth in numerous rules subsequently promulgated by the CFTC and other agencies. Because the CFTC has not yet clearly articulated the scope of key definitions in the Dodd-Frank Act, such as “swap,” “swap dealer” and “major swap participant,” and because the parameters of Dodd-Frank Act requirements are still shifting, it is impossible to know exactly how the Dodd-Frank Act will impact our business. However, the issuance of any rules or regulations relating to the Dodd-Frank Act that subject us to additional business conduct standards, position limits and/or reporting, capital, margin or clearing requirements with respect to our commodity swap risk management positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities. If we are required to

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post additional collateral as a result of new rules, we would have to do so by utilizing cash or letters of credit, which would reduce our liquidity position and increase costs. These changes could materially reduce our hedging opportunities and increase the costs associated with our hedging programs, both of which could negatively 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 our oil and gas properties. Under full cost accounting rules, the net capitalized cost of our oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from our proved reserves, discounted at 10%. If the net capitalized costs of our 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 it does reduce our stockholders' equity and earnings. The risk that we will be required to write-down the carrying value of our oil and gas properties increases when oil and gas prices are low, which could be further impacted by the SEC's modernized oil and gas reporting disclosures, which require us to use an average price over the prior 12-month period, rather than the year-end price, when calculating the PV-10. 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 in the subsequent period.

At December 31, 2010, the net capitalized costs of our United States oil and gas properties did not exceed the present value of our estimated proved reserves; however, the net capitalized costs of our Canadian oil and gas properties exceeded the present value of our estimated proved reserves by approximately $4.8 million, resulting in a write down of $4.8 million. At December 31, 2011, the net capitalized cost of our United States and Canadian oil and gas properties did not exceed the present value of our estimated proved reserves.

Use of our net operating loss carryforwards may be limited.

At December 31, 2011, we had, subject to the limitation discussed below, $150.2 million of net operating loss carryforwards for U.S. tax purposes and $7.7 million for Canadian tax purposes. The U.S. loss carryforwards will expire in varying amounts through 2031, and the Canadian carryforward will expire in 2031, 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 to a limited number of investors) during the three-year period following the merger with the Partnership, 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. Therefore, in accordance with Financial Accounting Standards Board ("FASB") and Accounting Standards Codification ("ASC") 740-10, we have established a valuation allowance of $83.5 million at December 31, 2011.

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

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Our financial statements are complex and our control environment cannot completely prevent fraud or human error.

Due to the nature of our business, and accounting principles generally accepted in the United States of America, our financial statements are complex, particularly with reference to derivative contracts, asset retirement obligations, deferred taxes and the accounting for our stock-based compensation plans. We expect such complexity to continue and possibly increase. Because of these complexities, many of our accounting processes are done manually and are dependent upon individual data input or review. While we continue to automate our processes and enhance our review and put in place controls to reduce the likelihood for errors, we expect that for the foreseeable future many of our processes will remain manually intensive and thus subject to human error.

A control environment, no matter how well conceived and operated, can provide only reasonable assurance that the objectives of the control environment are met. Because of the inherent limitations in all control environments, no evaluation of controls can provide absolute assurance that all control issues have been detected and misstatements due to error or fraud may occur and not be detected.

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. Low gas prices have affected us more than oil prices because 55% of our production during 2011 and 46% of our proved reserves at December 31, 2011 were gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also make it uneconomical for us to increase or even continue current production levels of 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;
- weather conditions;
- price and level of foreign imports;
- terrorist activity;
- availability of pipeline and other secondary capacity;
- 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 if 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 and involves 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. 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.

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The estimates of our reserves as of December 31, 2011 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 first-day-of-the-month average oil and gas prices for the year ended December 31, 2011. The average realized sales prices as of such date used for purposes of such estimates were $3.97 per Mcf of gas and $88.94 per Bbl of oil. The December 31, 2011 estimates also assume that we will make future capital expenditures of approximately $228.8 million in the aggregate primarily from 2012 through 2016, which are necessary to develop and realize the value of proved reserves on our properties. In addition, approximately 43% of our total estimated proved reserves as of December 31, 2011 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 report.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

As required by SEC regulations, we based the estimated discounted future net cash flows from our proved reserves as of December 31, 2011 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2011 and costs in effect on December 31, 2011, the date of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

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

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, discharges of toxic gases, underground migration and surface spills or mishandling of any toxic fracture fluids, including chemical additives. 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, environmental damage, 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.

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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 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, we cannot assure you that such resources will be available to us in the future.

Our oil and gas operations are subject to various U.S. Federal, state, local and Canadian provincial regulations that materially affect our operations.

In the oil and gas industry, matters regulated include permits for drilling and completion 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. U.S. Federal, state, local, and Canadian provincial laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products 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.

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.

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 by-product of the burning of oil, 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.

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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. The 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 and as a result, our financial condition and results of operations could be adversely affected.

Risks Related to Our Common Stock

Future issuance of additional shares of common stock could cause dilution of ownership interests and adversely affect our 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 will not pay dividends on our common stock for the foreseeable future.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. In addition, our credit facility prohibits us from paying dividends and making other cash distributions.

Shares eligible for future sale may depress our stock price.

At December 31, 2011, we had 92,261,057 shares of common stock outstanding of which 6,178,515 shares were held by affiliates and, in addition, 4,756,255 shares of common stock were subject to outstanding options granted under stock option plans (of which 2,511,790 shares were vested at December 31, 2011).

All of the shares of common stock held by affiliates are restricted or control securities under Rule 144 promulgated under the Securities Act. 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;

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- general trends in the oil and gas industry;
- sales of common stock or other actions by our stockholders;
- additions or departures of key management personnel;
- commencement of or involvement in litigation;
- speculation in the press or investment community regarding our business;
- an inability to maintain the listing of our common stock on a national securities exchange;
- market conditions; and
- analysts' estimates and other events in the oil and gas 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 us 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 our articles of incorporation, bylaws and our tax benefits preservation plan, could make it more difficult for a third party to acquire us without the approval of our board. In addition, the Nevada corporate statute also contains certain provisions that could make an acquisition by a third party more difficult. 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.

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 sets forth our developed and undeveloped acreage and fee mineral acreage as of December 31, 2011. There are no material lease expirations in 2012.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage (1)		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres (2)
Rocky Mountain	61,757	31,431	71,293	48,736	1,400	1,160	81,327
Mid-Continent	23,840	5,580	240	120	543	69	5,769
Permian Basin	25,519	17,960	18,917	17,747	12,007	5,272	40,979
Onshore Gulf Coast	5.801	5,173	1,918	1,882	—	—	7,055
Total United States	116,917	60,144	92,368	68,485	13,950	6,501	135,130
Alberta, Canada	960	960	23,840	23,840	—	—	24,800
Total	117,877	61,104	116,208	92,325	13,950	6,501	159,930

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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 in the Permian Basin region that are included in both developed and undeveloped gross acres. Does not include net acres owned by Blue Eagle in the onshore Gulf Coast region.

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2011:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Rocky Mountain	539.0	91.3	502.0	15.6
Mid-Continent	6.0	3.5	142.0	29.9
Permian Basin	160.0	133.3	61.0	29.0
Onshore Gulf Coast (1)	33.5	33.5	24.5	20.3
Total United States	738.5	261.6	729.5	94.8
Alberta, Canada	4.0	4.0	—	—
Total	742.5	265.6	729.5	94.8

(1) Excludes 3.0 gross (2.4 net) wells owned by Blue Eagle.

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 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.

For the year ended December 31, 2011, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for Abraxas' properties comprising approximately 99% of the PV-10 of our proved oil and gas reserves and for 100% of Blue Eagle's properties. Proved reserves for the remaining 1% of our properties were estimated by Abraxas personnel. DeGolyer and MacNaughton's reserve report as of December 31, 2011 for Abraxas included a total of 870 properties and our internal report included 445 properties.

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 any of our properties and are not employed on a contingent fee basis. All reports by DeGolyer and MacNaughton were developed utilizing geological and engineering data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 21, 2012, 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 reserves at December 31, 2011 were based on studies performed by the operations department of Abraxas which 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 26 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, include oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages which are obtained from other departments within Abraxas.

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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 SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations or de-escalations except by contractual arrangements. For the year ended December 31, 2011, commodity prices over the prior 12-month period and year end costs were used in estimating future net cash flows.

In addition to proved reserves, we disclose our “probable” and “possible” reserves in this report. Probable reserves are those additional reserves that are less likely to be recovered than proved reserves. Possible reserves are those additional reserves that are less likely to be recoverable than probable reserves. These estimates of probable and possible reserves are by their very nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by us.

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2011, which excludes reserves attributable to our equity interest in Blue Eagle. All of our reserves are located in the United States and Canada.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2011

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil Equivalents (MBoe)
Proved				
Developed	6,690.2	1,069.9	42,582.2	14,857.2
Undeveloped	5,959.3	500.5	29,493.1	11,375.3
Total Proved	12,649.5	1,570.4	72,075.3	26,232.5
Probable				
Developed Producing	157.7	6.1	479.9	243.8
Developed Non-producing	65.8	—	1,168.7	260.6
Undeveloped	7,719.8	1,972.6	55,919.7	19,012.4
Total Probable	7,943.3	1,978.7	57,568.3	19,516.8
Possible				
Undeveloped	11,460.7	544.9	19,602.1	15,272.7
Total	32,053.5	4,094.0	149,245.7	61,022.0

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2011, 2010, and 2009, and changes in proved reserves during the last three years are presented in the Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information) under Item 8 of this Report. Also presented in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves.

We have not filed information with a federal authority or agency with respect to our estimated total proved reserves at December 31, 2011. We report gross proved reserves of operated properties in the United States to the U.S.

Department of Energy on an annual basis; these reported reserves are derived from the same data used to estimate and report proved reserves in this Form 10-K.

The process of estimating oil and gas reserves is complex and involves 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

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those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves set forth or incorporated by reference in this report. We may also adjust estimates of 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. In particular, estimates of oil and gas reserves, future net revenue from 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, 2011 report. The average realized sales prices used for purposes of such estimates were $88.94 per Bbl of oil and $3.97 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $228.8 million in the aggregate primarily in the years 2012 through 2016, 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.

You should not assume that the present value of future net revenues referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves is calculated using the average first-day-of-the-month price over the prior 12-month period. Costs used in the estimated discounted future net cash flows are costs as of the end of the period. 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, 2011, the Company’s net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. Based on managements’ review of average first-day-of-the-month prices for the twelve months of April 2011 through March 2012, we do not anticipate a write down at the end of the first quarter of 2012.

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. Our effective interest rate on borrowings 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.

Proved Undeveloped Reserves (“PUDs”)

Changes in PUDs. Significant changes to PUDs occurring during 2011 are summarized in the table below. Revisions of prior estimates reflect the addition of new PUDs associated with current development plans, revisions to prior PUDs, revisions to infill drilling development plans, as well as the transfer of PUDs to unproved reserve categories due to changes in development plans during the period. Our year-end development plans are consistent with SEC guidelines for PUDs development within five years unless specific circumstances warrant a longer development time horizon.

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MMBoe	
PUDs at December 31, 2010	10,959
Revisions of prior estimates	(380)
Extensions, discoveries, and other additions	723
Conversion to developed	74
Sales	—
PUDs at December 31, 2011	11,376

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 standardized measure calculation for 2009 and 2010 relating to our reserves. For 2011, there was an income tax impact on our reserves. As a result, there was no difference between the standardized measure of our oil and gas reserves for 2009 and 2010, however for 2011 there was a difference of $28.9 million, between the standardized measure of our oil and gas reserves which is a GAAP financial measure and the PV-10 of our reserves.

Blue Eagle Reserve Data

The following table sets forth certain information attributable to our 34.7% equity interest in the estimates of Blue Eagle's oil and gas reserves as of December 31, 2011. For the year ended December 31, 2011, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for 100% of Blue Eagle's properties. For a description of the qualifications of DeGolyer and MacNaughton, and our internal controls and the qualifications of the technical person primarily responsible for preparing reserve estimates, please see the discussion above under "Reserves Information." All of Blue Eagle's reserves are located in the United States.

Summary of Oil, NGL and Gas Reserves – Blue Eagle
As of December 31, 2011

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil Equivalents (MBoe)
Proved				
Developed	91.2	110.4	1,341.4	425.2
Undeveloped	440.3	651.2	7,647.9	2,366.1
Total Proved	531.5	761.6	8,989.3	2,791.3
Probable				
Undeveloped	2,457.8	741.8	8,899.5	4,683.0

Possible				
Undeveloped	890.2	127.4	1,395.4	1,250.2
Total	3,879.5	1,630.8	19,284.2	8,724.5

The following table sets forth certain information regarding the combined reserves of Abraxas and the reserves attributable to Abraxas' 34.7% equity interest Blue Eagle as of December 31, 2011.

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Summary of Oil, NGL and Gas Reserves – Combined Abraxas and Blue Eagle
As of December 31, 2011

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil Equivalents (MBoe)
Proved				
Developed	6,781.5	1,180.3	43,923.7	15,281.9
Undeveloped	6,399.5	1,151.6	37,141.0	13,741.4
Total Proved	13,181.0	2,331.9	81,064.7	29,023.3
Probable				
Producing	157.7	6.1	479.9	243.8
Developed	65.8	—	1,168.7	260.6
Undeveloped	10,177.7	2,714.5	64,819.1	23,695.4
Total Probable	10,401.2	2,720.6	66,467.7	24,199.8
Possible				
Undeveloped	12,350.9	672.3	20,997.5	16,522.9
Total	35,933.1	5,724.8	168,529.9	69,746.4

Oil and Gas Production, Sales Prices and Production Costs

The following table presents our net oil, gas and NGL production, the average sales price per Bbl of oil and NGL and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three years ended December 31, 2011:

	2009	2010	2011
Oil production (Bbls)			
Rocky Mountain	329,667	286,114	310,819
Permian Basin	117,172	107,763	113,151
Onshore Gulf Coast	81,775	75,571	93,182
Other (4)	43,910	29,260	22,738
Total	572,524	498,708	539,889
Gas production (Mcf)			
Rocky Mountain	611,714	570,736	474,269
Permian Basin	2,297,465	2,135,918	1,891,333
Onshore Gulf Coast	2,119,413	1,757,901	1,482,260
Other (4)	1,300,624	1,014,347	373,970
Total	6,329,216	5,478,902	4,221,832
NGL production (Bbls)			
Rocky Mountain	3,200	4,228	11,451
Permian Basin	383	278	15,171
Onshore Gulf Coast	230	79	231
Other (4)	2,447	5,624	1,271
Total	6,260	10,209	28,124
Total production (MBoe) (1)	1,634	1,422	1,272
Average sales price per Bbl of oil (2)			
Rocky Mountain	$ 56.07	$ 68.79	$ 85.73
Permian Basin	$ 56.97	$ 75.94	$ 91.07
Onshore Gulf Coast	$ 57.50	$ 77.32	$ 97.09
Other (4)	$ 57.99	$ 76.13	$ 91.62
Composite	$ 54.15	$ 71.37	$ 89.06

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Average sales price per Mcf of gas (2)						
Rocky Mountain	$	3.50	$	4.28	$	3.77
Permian Basin	$	3.21	$	4.00	$	3.81
Onshore Gulf Coast	$	3.06	$	3.62	$	3.31
Other (4)	$	3.21	$	4.32	$	3.28
Composite	$	3.24	$	3.97	$	3.58
Average sales price per Bbl of NGL						
Rocky Mountain	$	31.93	$	42.03	$	49.71
Permian Basin	$	23.15	$	34.48	$	48.27
Onshore Gulf Coast	$	26.78	$	38.03	$	45.75
Other (4)	$	28.50	$	34.79	$	75.69
Composite	$	29.86	$	37.81	$	50.08
Average sales price per Boe (2)	$	31.73	$	40.82	$	50.81
Average cost of production per Boe produced (3)						
Rocky Mountain	$	18.00	$	17.34	$	19.58
Permian Basin	$	11.52	$	11.88	$	13.16
Onshore Gulf Coast	$	5.64	$	6.06	$	7.81
Other (4)	$	10.86	$	9.36	$	16.89
Composite	$	12.50	$	13.81	$	16.94

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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 lease operating costs but exclude ad valorem taxes and production taxes.

(4) Includes Canada and Mid-Continent comprising approximately 6% of total production.

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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, 2011:

	2009		2010 (1)		2011 (2)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Rocky Mountain	—	—	1.0	1.0	2.0	1.1
Permian Basin	1.0	1.0	1.0	0.4	1.0	1.0
Onshore Gulf Coast	—	—	—	—	—	—
Other (3)	—	—	—	—	—	—-
Total	1.0	1.0	2.0	1.4	3.0	2.1
Dry wells						
Permian Basin	—	—	—	—	1.0	1.0
Onshore Gulf Coast	—	—	1.0	1.0	—-	—
Total	—-	—	1.0	1.0	1.0	1.0
Development						
Productive						
Rocky Mountain	9.0	1.1	16.0	1.8	12.0	1.2
Permian Basin	3.0	0.1	2.0	2.0	2.0	2.0
Onshore Gulf Coast	—	—	3.0	3.0	7.0	7.0
Other (3)	2.0	0.1	3.0	2.0	4.0	4.0
Total	14.0	1.3	24.0	8.8	25.0	14.2
Dry wells						
Onshore Gulf Coast	1.0	1.0	—	—	—	—
Total	1.0	1.0	—	—	—	—

(1) Excludes 1.0 gross (1.0 net) well drilled by Blue Eagle.

(2) Excludes 2.0 gross (1.4 net) wells drilled by Blue Eagle.

(3) Includes drilling activities in Canada and Mid-Continent.

Present Activities

As of March 12, 2012, we had 3 operated wells and 5 non-operated wells in process of drilling and/or completing. The following provides an overview of our present activities by region:

Rocky Mountain – North Dakota / Montana

- In the Bakken / Three Forks play in the Williston Basin, during the fourth quarter of 2011, 1 gross (<1% net) non-operated well came on-line and 2 gross (0.3 net) wells are currently drilling or awaiting completion. Additionally, we have recently elected to participate in 6 gross (0.6 net) wells that have yet to spud.
- The refurbishment of the Company owned drilling rig has been completed and the rig is currently on its way to McKenzie County, North Dakota to begin drilling its first multi-well pad site.

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Rocky Mountain – Wyoming

- In Campbell County, Wyoming, the Hedgehog State 16-2H, a horizontal well targeting the Turner formation, was recently completed with a 17-stage fracture stimulation. The well is currently flowing back with encouraging initial results. Abraxas owns a 100% working interest in this well.

South Texas – Eagle Ford

- At December 31, 2011, Abraxas owned a 34.7% equity interest in Blue Eagle, a joint venture between Abraxas and Rock Oil Company, LLC.
- In McMullen County, Texas, the Cobra 1H, a horizontal well targeting the Eagle Ford Shale, was recently completed with a 15-stage fracture stimulation. The well is currently flowing back at very promising rates. Blue Eagle owns a 100% working interest in this well.

Canada – Pekisko

- In Alberta, Canada, the pipeline hook-up for three wells is underway and should be completed within the next few weeks. Two wells continue to await stimulation; however, the completions have been delayed as the availability of acid for the stimulations is in short supply. Canadian Abraxas owns a 100% working interest in each of these wells which have targeted the Pekisko formation.

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. We own the building which is subject to a real estate lien note. The note bears interest at a fixed rate of 5.25%, and is payable in monthly installments of principal and interest of $36,652 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, 2011, $4.9 million was outstanding on the note. We lease office space in Calgary, Alberta for a monthly rental of $3,836 CN. The lease expires on January 31, 2014. We lease office space in Dickinson, North Dakota for a monthly rental of $1,850. The lease expires on August 31, 2012.

Other Properties

We own 1,779 acres of land, including an office building, workshop, warehouse and house in San Patricio County, 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, 600 acres of land in McKenzie County, North Dakota and 12,177 acres of land in Pecos County, Texas.

We own 22 vehicles which are used in the field by employees. We own two workover rigs, which are used for servicing our wells. Raven Drilling, owns a 2000 HP drilling rig, primarily to be used for drilling wells in the Williston Basin. We own two condominiums in Dickinson, North Dakota and a man-camp in North Dakota to house rig crews.

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, 2011, 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. Mine Safety Disclosures

Not applicable

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Part II

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

Market Information

Our common stock is traded 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 our common stock.

Period	High	Low
2010		
First Quarter	$ 2.50	$ 1.78
Second Quarter	3.16	1.89
Third Quarter	3.14	2.30
Fourth Quarter	4.69	2.69
2011		
First Quarter	$ 6.16	$ 4.06
Second Quarter	5.97	3.01
Third Quarter	5.18	2.50
Fourth Quarter	4.45	1.86
2012	$ 4.39	$ 3.13
First Quarter (Through March 12, 2012)	$ 4.39	$ 3.13

Holders

As of March 12, 2012, we had 92,261,057 shares of common stock outstanding and approximately 1,179 stockholders of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, 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 our 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 $1.2 billion (the "Comparable Companies"). The Comparable Companies are: Double Eagle Petroleum Co., Endeavor 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 our common stock and each index as $100.00 on December 31, 2006, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2007, 2008, 2009, 2010 and 2011.

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	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2008	Dec. 31, 2009	Dec. 31, 2010	Dec. 31, 2011
Small Cap Index	$ 100.00	$ 124.75	$ 42.67	$ 55.85	$ 108.48	$ 115.70
S&P 500	$ 100.00	$ 103.53	$ 63.69	$ 78.62	$ 88.67	$ 88.67
AXAS	$ 100.00	$ 124.92	$ 23.30	$ 62.14	$ 147.90	$ 106.80

The information contained above under the caption “Performance Graph” is being “furnished” to the SEC and shall not be deemed to be “soliciting material” or to be “filed” with the SEC, 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.

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Item 6. Selected Financial Data

The following selected financial data is derived from our Consolidated Financial Statements as of and for the years ended December 31, 2007 through 2011. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto and other financial information included herein. See "Financial Statements and Supplementary Data" in Item 8.

	Year Ended December 31,				
	2007	2008	2009	2010	2011
	(In thousands, except per share data)				
Total revenue	$ 46,913	$ 99,100	$ 51,836	$ 58,060	$ 64,622
Net income (loss)	$ 56,702(1)	$ (52,403)(2)	$ (18,780)	$ 1,766(3)	$ 13,743
Net income (loss) per common share – diluted	$ 1.19	$ (1.07)	$ (0.34)	$ 0.02	$ 0.15
Weighted average shares outstanding – diluted	47,593	49,005	55,499	77,362	92,224
Total assets	$ 147,119	$ 211,839	$ 176,236	$ 182,909	$ 241,150
Long-term debt, excluding current maturities	$ 45,900	$ 130,835	$ 143,592	$ 140,940	$ 126,258
Total stockholders' equity (deficit)	$ 55,847	$ 4,658	$ (18,363)	$ (14,976)	$ 62,651

(1) Includes gain on sale of assets of $59.4 million.
(2) Includes proved property impairment of $116.4 million.
(3) Includes proved property impairment of $4.8 million.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion excludes the operations of Blue Eagle, except our equity share of Blue Eagle's income (loss). This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See "Financial Statements and Supplementary Data" in Item 8.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States and Canada. 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 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, 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

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the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Recently, the prices of oil and gas have been volatile. During the first half of 2009, there was a significant drop in prices. Prices began to improve during the second half of 2009 and 2010. During 2011, the price of oil increased from the levels experienced in 2010. The New York Mercantile (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $96.19 per barrel in 2011 as compared to $79.51 per barrel in 2010. During 2011, the average price of gas decreased from an average NYMEX Henry Hub spot price of $4.38 per MMBtu in 2010 to $4.16 per MMBtu in 2011. Prices closed on December 31, 2011 at $98.83 per Bbl of oil and $2.96 per MMBtu of gas. If commodity prices decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. 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 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.

The following table sets forth our average differentials for the years ended December 31, 2009, 2010 and 2011:

	Oil - WTI			Gas – Henry Hub		
	2009	2010	2011	2009	2010	2011
Average realized price	$54.15	$71.37	$89.06	$3.24	$3.97	$3.58
Average NYMEX price	$61.82	$79.51	$96.19	$3.94	$4.38	$4.16
Differential	$(7.67)	$(8.14)	$(7.13)	$(0.70)	$(0.41)	$(0.58)

Our hedging arrangements equate to approximately 67% of the estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2011) through December 31, 2012 and 59% 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, we 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. In 2009, we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 million. In 2010, we incurred a realized gain of $2.8 million and an unrealized gain of $11.4 million. In 2011, we incurred a realized gain of $1.7 million and an unrealized gain of $5.7 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, 2011:

Fixed Price Swap

	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (MMbtu)	Swap Price
2012	946	$70.89	8,303	$6.77
2013	705	$80.79	5,962	$6.84

At December 31, 2011, the aggregate fair market value of our oil and gas derivative contracts was an asset of approximately $3.4 million.

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On March 12, 2012, we monetized our gas derivative contacts for $12.4 million. Simultaneously, we entered into new oil commodity swaps on as summarized below.

The following table sets forth our oil derivative contract position related to the new swap agreements:

Contract Period	Daily Volume (Bbl)		Swap Price
2012	228	(1)	$108.42
2013	289		$105.61
2014	840	(2)	$100.71

1. For the months of July through December 2012.
2. For the months of January through August 2014.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve estimates as of December 31, 2011 (which did not include any of Blue Eagle's reserves), our average annual estimated decline rate for net proved developed producing reserves is 14% 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 property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures during 2011 of $56.2 million related to our exploration and development activities. We have a capital expenditure budget for 2012 of $70 million, an increase of approximately 17% over 2011. Approximately 75% of the 2012 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region and the other 25% will target conventional oil plays in the Permian Basin and in the province of Alberta, Canada. The 2012 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the years ended December 31, 2009, 2010 and 2011:

	Year Ended December 31, 2009		2010		2011	
Total production (MBoe)	1,634		1,422		1,272	
Average daily production (Boepd)	4,476		3,896		3,484	
% Oil/ NGL	35	%	36	%	45	%

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an appropriate opportunity presents itself, the sale 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, 2011, we had $10.0 million of availability under our credit facility.

Borrowings and Interest. At December 31, 2011, we had a total of $115.0 million outstanding under our credit facility. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our 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 for $100 million at a fixed rate of 3.367% originally expired 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.

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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, 2011, we operated properties accounting for approximately 94% 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 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, 2011, we drilled or participated in 127 gross (42.38 net) wells of which 96.8% were 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 43% of our estimated proved reserves at December 31, 2011 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.

Results of Operations

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

	Years Ended December 31, (In thousands, except per unit data)		
	2009	2010	2011
Operating revenue (1):			
Oil sales	$31,153	$35,935	$48,080
Gas sales	20,489	21,729	15,127
NGL sales	187	386	1,408
Total operating revenues	$51,829	$58,050	$64,615
Operating income (2)	$177	$2,807	$11,648
Oil sales (MBbls)	572.5	498.7	539.9
Gas sales (MMcf)	6,329.2	5,478.9	4,221.8
NGL sales (MBbls)	6.3	10.2	28.1
Oil equivalents (MBoe)	1,633.2	1,422.1	1,271.6
Average oil sales price (per Bbl)(1)	$54.15	$71.37	$89.05
Average gas sales price (per Mcf)(1)	$3.24	$3.97	$3.58
Average NGL sales price (per Bbl)	$29.86	$37.81	$50.07
Average oil equivalent sales price (Boe)	$31.73	$40.82	$50.81

(1) Revenue and average sales prices are before the impact of hedging activities.
(2) Operating income includes a $4.8 million proved property impairment in 2010.

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Comparison of Year Ended December 31, 2011 to Year Ended December 31, 2010

Operating Revenue. During the year ended December 31, 2011, operating revenue increased to $64.6 million from $58.1 million in 2010. The increase in revenue was due to higher realized oil and NGL prices in 2011 as compared to 2010 which were partially offset by decreased prices for gas. Increased oil and NGL prices contributed $8.6 million to operating revenue while decreased gas prices had a negative impact of $2.1 million. Increased sales volumes of oil and NGL's were offset by a decrease in gas sales. Increased oil and NGL sales contributed $4.6 million to operating revenue. Decreased gas sales had a negative impact of $4.5 million on operating revenue.

Oil sales volumes increased to 539.9 MBbls for the year ended December 31, 2011 from 498.7 MBbls for the same period of 2010. The increase in oil sales volumes was due to new production brought on line in 2011. New wells brought onto production in 2011 contributed 94.3 MBbls to production for the year ended December 31, 2011, offset by sales of non-core properties during 2010 and natural field declines. The divested properties produced 29.5 MBbls during 2010. Gas sales volumes decreased to 4,221.8 MMcf for the year ended December 31 2011 from 5,478.9 MMcf for the year ended December 31, 2010. The decrease in gas production was due to sales of non-core properties during 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 754.9 MMcf in 2010. New wells brought onto production during 2011 contributed 148.7 MMcf to production for the year ended December 31, 2011. Due to weak gas prices, our focus was primarily on oil projects during 2011. NGL sales increased to 28.1 MBbls in for the year ended December 31, 2011 from 10.2 MBbls for the same period of 2010. The increase in NGL sales was primarily due to increased gas production in West Texas and North Dakota that has a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the year ended December 31, 2011 increased to $21.6 million from $19.5 million in 2010. The increase in LOE was primarily due to increased cost of services. LOE per Boe for the year ended December 31, 2011 was $16.97 compared to $13.69 for the same period of 2010. The increase in LOE per Boe was attributable to lower sales volumes and higher costs in 2011 as compared to 2010.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2011 decreased to $5.8 million from $5.9 million in 2010 as a result of lower gas prices, which were offset by higher oil prices. Production and ad valorem taxes as a percentage of oil and gas revenue decreased to 9% for the year ended December 31, 2011 from 10% in 2010. In addition, total sales volumes were lower in 2011 as compared to 2010.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased to $7.4 million for the year ended December 31, 2011 from $7.3 million in 2010. The increase in G&A was primarily related to higher salaries in 2011. G&A per Boe was $5.85 for the year ended December 31, 2011 compared to $5.14 for the same period of 2010. The increase in G&A per Boe was primarily due to lower production volumes and higher costs in 2011 compared to 2010.

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 and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation for the year ended December 31, 2011 increased to $2.0 million from $1.6 million in 2010. The increase in 2011 as compared to 2010 was due to higher values of grants made during 2011 as compared to 2010, and to additional grants during the third quarter of 2011.

Depletion, Depreciation and Amortization ("DD&A") Expenses. DD&A expense for the years ended December 31, 2011 and 2010 was constant at $16.2 million in each year. Our DD&A rate increased due to higher future development cost in the 2011 year end reserve report, offset by higher reserves. DD&A per Boe for 2011 was $12.73 compared to $11.40 in 2010. The increase in DD&A per BOE was due to lower sales volumes in 2011 as compared to 2010.

Interest Expense. Interest expense decreased to $4.9 million in 2011 from $9.1 million for 2010. The decrease in interest expense for the year ended December 31, 2011 was primarily due to lower levels of debt as compared to 2010 and lower interest rates.

Income Taxes. An income tax benefit of $79,000 was recognized in 2010 as a result of a decrease in the $1.3 million tax basis gain on the Merger. In 2011, we recognized a tax benefit of $77,000 as the result of a refund of alternative minimum tax paid in 2010.

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Loss (Gain) on 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 net estimated value of our commodity and interest rate derivative contracts was an asset of approximately $1.9 million as of December 31, 2011. 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, 2011, we realized a loss on our derivative contracts of $676,000, which included a realized gain of $1.7 million on our commodity swaps and a realized loss of $2.4 million on our interest rate swap. For the year-ended December 31, 2011, we incurred an unrealized gain of $7.5 million on our derivative contracts, which included an unrealized gain of $5.7 on our commodity swaps and $1.8 million on our interest rate swap. The estimated value of our derivative contracts was a liability of approximately $5.8 million as of December 31, 2010. 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, 2010, we realized a gain on our derivative contracts of $526,000, which included a realized gain of $2.8 million on our commodity swaps and a realized loss of $2.3 million on our interest rate swap. For the year-ended December 31, 2010, we incurred an unrealized gain of $10.3 million on our derivative contracts, which included an unrealized gain of $11.4 million on our commodity swaps and an unrealized loss of $1.1 million on our interest rate swap.

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 and reported earnings. As of December 31, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of December 31, 2010, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $4.8 million, resulting in a write down of $4.8 million. These amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2010 which were $79.43 per Bbl for oil and $4.45 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas 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. 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 of April 2011 through March 2012, we do not anticipate a write-down at the end of the first quarter of 2012.

Equity in (Income) Loss of Joint Venture. We account for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture is reflected as an increase (decrease) in its investment account in "Investment in joint venture" and is also recorded as equity investment income (loss) in "Equity in loss (income) of joint venture." For the year ended December 31, 2011, our net share of the joint venture's income was $2.2 million.

Comparison of Year Ended December 31, 2010 to Year Ended December 31, 2009

Operating Revenue. During the year ended December 31, 2010, operating revenue increased to $58.1 million from $51.8 million in 2009. The increase in revenue was due to higher realized commodity prices in 2010 as compared to 2009 which were partially offset by decreased sales volumes in 2010 as compared to 2009. The increase in commodity prices contributed $12.8 million to revenue while decreased sales volumes had a negative impact of $6.5 million.

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Oil sales volumes decreased to 498.7 MBbls for the year ended December 31, 2010 from 572.5 MBbls for the same period of 2009. The decrease in oil sales volumes was due to sales of non-core properties during the latter part of the fourth quarter of 2009 and during 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 29.5 MBbls during 2010, compared to 67.8 MBbls during 2009. New wells brought onto production in 2010 contributed 23.9 MBbls to production for the year ended December 31, 2010. Gas sales volumes decreased to 5,478.9 MMcf for the year ended December 31 2010 from 6,329.2 MMcf for the year ended December 31, 2009. The decrease in gas production was due to sales of non-core properties during the latter part of the fourth quarter of 2009 and during 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 931.2 MMcf in 2009 compared to 754.9 MMcf in 2010. New wells brought onto production during 2010 contributed 190.8 MMcf to production for the year ended December 31, 2010.

Lease Operating Expenses ("LOE"). LOE for the year ended December 31, 2010 decreased to $19.5 million from $20.3 million in 2009. LOE per Boe for the year ended December 31, 2010 was $13.69 compared to $12.40 for the same period of 2009. The increase in LOE per Boe was attributable to lower production volumes in 2010 as compared to 2009.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2010 increased to $5.9 million from $5.8 million in 2009 as a result of higher commodity prices which result in higher production taxes.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased to $7.3 million for the year ended December 31, 2010 from $6.5 million in 2009. The increase in G&A was primarily related to the opening of our Canadian office in September 2009. G&A per Boe was $5.14 for the year ended December 31, 2010 compared to $3.96 for the same period of 2009. The increase in G&A per Boe was primarily due to lower production volumes and higher costs in 2010 compared to 2009.

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 and are valued at the date of grant and expense is recognized over their vesting period. For the years ended December 31, 2010 and 2009, stock-based compensation was approximately $1.6 million and $1.2 million, respectively. The increase in 2010 as compared to 2009 was due to the grant of options in the fourth quarter of 2009 related to the Merger and new grants during 2010.

Depletion, Depreciation and Amortization ("DD&A") Expenses. DD&A expense decreased to $16.2 million in 2010 from $17.9 million in 2009. The decrease in DD&A was primarily the result of a lower reserve base due to the sale of properties during 2010 and the contribution of acreage to Blue Eagle, which also reduced our full cost pool. DD&A per Boe for 2010 was $11.40 compared to $10.95 in 2009.

Interest Expense. Interest expense decreased to $9.1 million in 2010 from $11.3 million for 2009. The decrease in interest expense for the year ended December 31, 2010 was primarily due to lower levels of debt as compared to 2009.

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. An income tax benefit of $79,000 was recognized in 2010 as a result of a decrease in the $1.3 million tax basis gain on the Merger.

Loss (Gain) on 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 $5.8 million as of December 31, 2010. 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

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year ended December 31, 2010, we realized a gain on our derivative contracts of $526,000, which included a realized gain of $2.8 million on our commodity swaps and a realized loss of $2.3 million on our interest rate swap. For the year-ended December 31, 2010, we incurred an unrealized gain of $10.3 million on our derivative contracts, which included an unrealized gain of $11.4 million on our commodity swaps and an unrealized loss of $1.1 million on our interest rate swap. 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.

Other Expense. 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 and reported earnings. As of December 31, 2010, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves; however, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $4.8 million, resulting in a write down of $4.8 million. These amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2010 which were $79.43 per Bbl for oil and $4.45 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves. As of December 31, 2009, our net capitalized costs of our United States oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2009, we did not own any properties outside of the United States.

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. 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 net income (loss) of the Partnership for the period owned by the partners other than Abraxas. For the year ended December 31, 2009, the non-controlling interest in the net income of the Partnership was approximately $9.7 million. The Partnership was merged into Abraxas on October 5, 2009; accordingly, there was no non-controlling interest adjustment for the year ended December 31, 2010.

Equity in (Income) Loss of Joint Venture. We account for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture is reflected as an increase (decrease) in its investment account in "Investment in joint venture" and is also recorded as equity investment income (loss) in "Equity in loss (income) of joint venture." For year ended December 31, 2010, our net share of the joint venture's loss was $473,000.

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:

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

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- 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 grow the business through the development of existing properties and the acquisition of new properties.

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 any financings on terms acceptable to us, if at all.

Working Capital (Deficit). At December 31, 2011, our current liabilities of $39.5 million exceeded our current assets of $24.7 million resulting in a working capital deficit of $14.8 million. This compares to a working capital deficit of $8.9 million at December 31, 2010. Current liabilities at December 31, 2011 primarily consisted of the current portion of derivative liabilities of $11.6 million, trade payables of $21.4 million and revenues due third parties of $5.8 million.

Capital Expenditures. Capital expenditures in 2009, 2010 and 2011 were $16.5 million, $36.4 million and $79.0 million, respectively. The table below sets forth the components of these capital expenditures:

	Year Ended December 31,		
	2009	2010	2011
		(In thousands)	
Expenditure category:			
Exploration/Development	$16,151	$36,172	$56,245
Facilities and other	320	276	22,767
Total	$16,471	$36,448	$79,012

During 2009 and 2010 capital expenditures were primarily for the development of our existing properties. During 2011, capital expenditures were for the development of our existing properties, the purchase and refurbishment of a drilling rig, and the purchase of 1,769 acres of land (surface only) in our Portilla field in San Patricio County, Texas.

We anticipate making capital expenditures in 2012 of $70.0 million. The 2012 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, and ability to obtain permits for drilling locations. With the increased number of drilling rigs running, particularly in the Williston Basin and in the Eagle Ford Shale play, together with the increased number of stages on a given frac job, frac crews and equipment are in short supply. As a result, there may be a delay in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. 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 economic and industry conditions and commodity prices. Oil and gas prices are volatile and declined significantly during the first half of 2009. Oil prices increased during the second half of 2009 but gas prices have remained 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 expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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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,		
	2009	2010	2011
	(In thousands)		
Net cash provided by operating activities	$44,136	$24,102	$24,495
Net cash used in investing activities	(14,096)	(15,048)	(70,555)
Net cash (used in) provided by financing activities	(30,103)	(10,816)	45,966
Total	$(63)	$(1,762)	$(94)

Operating activities for the year ended December 31, 2011 provided $24.5 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 $46.0 million for the year ended December 31, 2011 which was primarily from the net proceeds from our equity offering in February 2011 of $62.3 million offset by a net reduction in our long term debt. Investing activities used $70.6 million in 2011 for the development of our oil and gas properties, the purchase and reconditioning of a drilling rig and the purchase of 1,769 acres of land (surface only) in our Portilla field in San Patricio County, Texas.

Operating activities for the year ended December 31, 2010 provided $24.1 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 property impairment of $4.8 million. Financing activities used $10.8 million for the year ended December 31, 2010 which was predominately the reduction of long-term debt. Investing activities used $15.0 million in 2010 for the development of our oil and gas properties, net of proceeds from sale of properties of $21.4 million.

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, net of proceeds from the sale of properties of $2.4 million.

Future Capital Resources. Our principal sources of capital going forward 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 first half of 2009. Oil prices increased during the second half of 2009 but gas prices have remained weak. A decrease in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop 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. Additionally, due to the increased number of drilling rigs running, particularly in the Williston Basin and in the Eagle Ford Shale play, together with the increased number of stages on a given frac job, frac crews and equipment are in short supply. As a result, there may be a delay in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. 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 43% of our total estimated proved reserves at December 31, 2011 were classified as undeveloped.

We have in the past and may in the future sell producing properties. Most recently, in the fourth quarter of 2009 and throughout 2010, we sold certain non-operated, non-core assets in nine different states for combined net proceeds of approximately $32.2 million (of which $8.5 million was received in February 2011) at various property auctions to numerous buyers. The net proceeds were used to repay outstanding indebtedness under our credit facility, for capital expenditures and general corporate purposes.

We have also sold debt and equity securities in the past when the opportunity has presented itself. On February 1, 2011, we closed a public offering of 23.6 million shares of common stock (of which 8.5 million shares were sold by certain selling stockholders) at a public offering price of $4.40 per share for total net proceeds to us of approximately $62.2 million, after estimated fees and expenses. We used the

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net proceeds from the offering to repay indebtedness outstanding under our credit facility, to increase our 2011 capital expenditure budget from $40 million to approximately $57 million and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

Subsequent to year end, on March 12, 2012, we monetized our gas derivative contracts for approximately $12.4 million.

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

- Long-term debt, and
- 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, 2011:

Contractual Obligations (In thousands)	Total	Payments due in twelve month periods ending: December 31, 2012	December 31, 2013-2014	December 31, 2015-2016	Thereafter
Long-term debt (1)	$126,939	$181	$2,774	$123,448	$536
Interest on long-term debt (2)	13,075	4,585	9,144	2,342	4
Lease obligations (3)	113	63	50	—	—
Total	$143,127	$4,829	$11,968	$125,790	$540

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These payments assume that we will not borrow additional funds. The rig loan was closed on February 14, 2012, accordingly, the amount includes an additional $500,000 drawn at closing.

(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 January 31, 2014 and office space in Dickinson, North Dakota, which expires on August 31, 2012.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2011, our reserve for these obligations totaled $8.4 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2011, 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 that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2011, 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, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, sales of debt and equity securities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

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Long-Term Indebtedness.

Long-term debt consisted of the following:

	December 31, 2010	December 31, 2011
	(In thousands)	
Credit facility	$136,000	$115,000
Rig loan agreement	—	6,500
Real estate lien note	5,092	4,939
	141,092	126,439
Less current maturities	(152)	(181)
	$140,940	$126,258

Credit Facility

On June 30, 2011, we entered into a second 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. As of December 31, 2011, $115.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $125.0 million and is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced 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 $125.0 million was determined based upon our reserve report dated June 30, 2011. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under 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 (b) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At December 31, 2011, the interest rate on the credit facility was 3.55% based on 1-month LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR 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 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, other than assets owned by Raven Drilling. Neither the properties owned by Blue Eagle nor our interest in Blue Eagle is used to secure the credit facility.

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 4.00 to 1.00. 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 a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20, and any accounts receivable from Blue Eagle and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account

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arising from the application of ASC 815 and ASC 410-20, and any accounts payable to Blue Eagle. 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. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts 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; provided that net income shall be adjusted to negate the effect of non-cash gain or loss attributable to Blue Eagle. 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. 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.

At December 31, 2011, we were not in compliance with the financial ratio that we maintain a current ratio, as of the last day of each quarter, of not less than 1.00 to 1.00, as defined. As of December 31, 2011, the current ratio was 0.81 to 1.00. We have received a waiver from our lenders for the quarter ended December 31, 2011 with respect to this covenant breach. Though we anticipate that the results of our operations combined with the monetization of our gas derivative contracts, which was completed on March 12, 2012, will allow us to remain in compliance with these covenants through the remainder of 2012, we will consider other actions such as sales of non-core assets if necessary.

As of December 31, 2011, the interest coverage ratio was 4.61 to 1.00 and the total debt to EBITDAX ratio was 3.90 to 1.00.

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.

Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing of an Oilwell 2000 hp diesel electric drilling rig (the “Collateral”). The rig loan agreement provides for interim borrowings payable to Raven Drilling or certain vendors on behalf of Raven Drilling until the final amount of the loan is determined. The rig loan agreement further provides for multiple notes in quantities of not less than $100,000 each with a maximum total of $7.0 million. Outstanding amounts under the interim borrowings will bear interest at LIBOR plus 3.50% and outstanding amounts under each note will bear interest at the four-year interest swap rate, published by the Federal Reserve, plus 3.50%, as determined at closing of each note. Upon closing of each note, interest only is due for the first 18-months (approximately) and thereafter, each note will amortize in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note will be 60 months after the closing of the note. At December 31, 2011, the interest rate on the rig loan agreement was 3.80% based on 1-month LIBOR borrowings.

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As of December 31, 2011, $6.5 million was outstanding under the rig loan agreement. On February 14, 2012, Raven finalized the note with respect to the rig loan agreement. The principal amount of the note is $7.0 million and bears interest at 4.26%, which equates to the four-year interest swap rate plus 3.50% on the date of closing. Interest only is due for the first 18-months of the note and will amortize in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017.

Abraxas Petroleum has guaranteed Raven Drilling's obligations under the rig loan agreement and associated notes. Obligations under the rig loan agreement are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in the Collateral.

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 5.25% and is payable in monthly installments of principal and interest of $36,652 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, 2011, $4.9 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. We have entered into commodity swaps on approximately 67% of our estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2011) through December 31, 2012 and 59% for 2013.

The following table sets forth our derivative contract position as of December 31, 2011:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
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 when 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 the year ended December 31, 2011, we incurred a realized gain of $1.7 million and an unrealized gain of $5.7 million on our commodity derivative contracts. For the year ended December 31, 2010, we incurred a realized gain of $2.8 million and an unrealized gain of $11.4 million on our commodity derivative contracts. For the year ended December 31, 2009, we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 million on our commodity derivative contracts. If the disparity between our 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, borrowings under our credit facility 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 development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

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On March 12, 2012, we monetized our gas derivative contacts for $12.4 million. Simultaneously, we entered into new oil commodity swaps on as summarized below.

The following table sets forth our oil derivative contract position related to the new swap agreements:

Contract Period	Daily Volume (Bbl)		Swap Price
2012	228	(1)	$108.42
2013	289		$105.61
2014	840	(2)	$100.71

(1) For the months of July through December 2012.
(2) For the months of January through August 2014.

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

Net Operating Loss Carryforwards

At December 31, 2011, we had, subject to the limitation discussed below, $150.2 million of net operating loss carryforwards for U.S. tax purposes and $7.7 million for Canadian tax purposes. The U.S. loss carryforwards will expire through 2031 and the Canadian carryforward will expire in 2031, 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 $83.5 million for deferred tax assets at December 31, 2011.

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 for the year ended December 31, 2011. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2011, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas in 2009, are currently undergoing an Internal Revenue Service audit of their 2009 Federal income tax returns.

Related Party Transactions

We have adopted a policy that transactions between us and our officers, directors, principal stockholders, or affiliates of any of them, will be on terms no less favorable to us than can be obtained on an arm's length basis in transactions with third parties and must be approved by our audit committee.

Environmental Regulations

Various federal, provincial, 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 on 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 we sent regulated substances for disposal or to which we 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 EPA's rule requiring annual reporting of greenhouse gas (GHG) emissions.

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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 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 strive to reduce GHG emissions throughout our operations which 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 U.S. generally accepted accounting principles (“GAAP”) 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 2010 relating to our proved oil and gas properties in Canada. 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 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 studies performed by the operations department of Abraxas and estimated 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 costs on the date of the estimate and for the years ended December 31, 2009, 2010 and 2011, oil and gas prices were based on the average 12-month first-day-of-the-month pricing as compared to end of period prices utilized in prior years. Actual future prices and costs may be materially higher or lower than the prices and costs used in 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 is 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 we 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. 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. Therefore, our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; as a result, 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, 2010 and 2011, the net market value of our commodity derivatives was a net liability of $2.5 million and a net asset of $3.4 million, respectively. The market value of our interest rate derivative was a liability of $3.3 million and $1.5 million at December 31, 2010 and 2011, 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 Note 7 to the consolidated financial statements. Options granted to employees and directors are valued at the date of grant and expense is recognized over

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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 and expense is recognized over the vesting period. For the years ended December 31, 2009, 2010 and 2011, stock-based compensation was approximately $1.2 million, $1.6 million, and $2.0 million, respectively.

Equity Method Investment. Our investment in an unconsolidated joint venture, in which we do not have a majority interest, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from our equity investment is reflected as an increase (decrease) in our investment account "Investment in joint venture" and is also recorded as "Equity in loss (income) of joint venture" in "Other (income) expense."

We review our equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

Recent Accounting Pronouncements

In 2010, the FASB issued an Accounting Standards Update ("ASU") to address diversity in practice in interpreting the pro forma revenue and earnings disclosure requirements for business combinations. The ASU specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the current year business combination(s) had occurred as of the beginning of the comparable prior annual reporting period. The adoption of this ASU will have no material impact on our consolidated financial statements.

In 2011, the FASB issued two ASUs which amend guidance for the presentation of comprehensive income. The amended guidance requires an entity to present components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive statements. The current option to report other comprehensive income and its components in the statement of stockholders' equity will be eliminated. Although the new guidance changes the presentation of comprehensive income, there are no changes to the components that are recognized in net income or other comprehensive income under existing guidance. These ASUs are effective for us in the first quarter of 2012 and retrospective application will be required. These ASUs will change our financial statement presentation of comprehensive income but will not impact our net income, financial position, or cash flows.

In 2011, the FASB issued an ASU which intended to reduce complexity and costs by allowing an entity the option to make a qualitative evaluation about the likelihood of goodwill impairment to determine whether it should calculate the fair value of a reporting unit. The ASU also expands upon the examples of events and circumstances that an entity should consider between annual impairment tests in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The ASU is effective for us in the first quarter of 2012, with early adoption permitted. The adoption of this ASU will have no impact on our consolidated financial statements.

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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 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 our 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 indices 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, 2011, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flow by approximately $6.5 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 contracts in accordance with ASC 815. 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. Therefore, our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; as a result, fluctuations in the market value of the derivative contract are recognized in earnings during the current period.

The following table sets forth our derivative contract position as of December 31, 2011:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
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 for $100 million at a fixed rate of 3.367% originally expired 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.

At December 31, 2011, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $3.4 million and the aggregate fair market value of our interest rate swap was a liability of approximately $1.5 million.

For the year ended December 31, 2011, we recognized a realized gain of $1.7 million and an unrealized gain of $5.7 million on our commodity derivative contracts and we recognized a realized loss of $2.3 million and an unrealized gain of $1.8 million 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, 2011, we had $115.0 million of outstanding indebtedness under our credit facility. Outstanding amounts under 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) 1.25%—2.25%, depending on the utilization of the borrowing base, or, if we elect, LIBOR plus 2.25%—3.25%, depending

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on the utilization of the borrowing base. At December 31, 2011, the interest rate on the credit facility was 3.55%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.2 million on an annual basis, based on our outstanding indebtedness as of December 31, 2011. 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 for $100 million at a fixed rate of 3.367% originally expired 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. 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, 2011 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, 2011.

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The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by BDO USA, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2011 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

There is incorporated in this Item 10 by reference to that portion of our definitive proxy statement for the 2012 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, Jr. 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 our directors and executive officers and persons who own more than 10% of a registered class of Abraxas equity securities to file with the SEC 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 2011.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2012 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 2012 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 2012 Annual Meeting of Stockholders which appears therein under the captions "Certain Transactions" and "Election of Directors – Director Independence."

Item 14. Principal Accounting Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2012 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services."

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PART IV

Item 15. Exhibits Financial Statement Schedules

(a)1. Consolidated Financial Statements

(a)2. Financial Statement Schedules

All schedules have been omitted because they are not required, not applicable, or the information required is included 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 dated August 30, 1990. (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).

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 flied on April 2, 2001).

3.6 Certificate of Correction dated February 24, 2011 (filed herewith).

3.7 Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on November 17, 2008).

3.8 Certificate of Designation of Series 2010 Junior Participating Preferred Stock. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on 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 our Registration Statement on Form 8-A filed on March 17, 2010).

*10.1 Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to our Registration Statement on Form S-4, No. 333-18673 filed on December 24, 1996).

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*10.2 Abraxas Petroleum Corporation Amended and Restated 1994 Long Term Incentive Plan. (Filed as Exhibit 10.4 to our Registration Statement on Form S-4, No. 333-120989 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 filed on January 24, 2000 (the “2000 S-1 Registration Statement”)).

*10.5 Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the Registration Statement on Form S-3, No. 333-127480 filed on September 16, 2005 (the “S-3 Registration Statement”)).

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

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

*10.8 Employment Agreement between Abraxas and Barbara M. Stuckey. (Filed herewith).

*10.9 Employment Agreement between Abraxas and G. William Krog, Jr. (Filed herewith).

*10.10 Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Appendix A to our Proxy Statement filed on April 15, 2010).

*10.11 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 our Current Report on Form 8-K filed June 6, 2005).

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

*10.13 Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Annex E to our Proxy Statement filed on September 8, 2009).

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

10.15 Limited Liability Company Agreement of Blue Eagle Energy, LLC dated August 18, 2010. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed August 23, 2010).

10.16 Form of Common Stock Purchase Warrant. (Filed as Exhibit 10.8 to our Current Report on Form 8-K filed May 31, 2007).

10.17 Amended and Restated Credit Agreement dated as of June 30, 2011 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 our Current Report on Form 8-K filed on July 6, 2011).

10.18 Loan Agreement dated as of September 19, 2011 between Raven Drilling, LLC, as Borrower, and RBS Asset Finance, Inc., as Lender. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on September 23, 2011).

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

18.1 Change in Accounting Principles. (Filed as Exhibit 18.1 to our 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 USA, 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 with respect to oil and gas reserves of Abraxas. (Filed herewith).

99.2 Report of DeGolyer and MacNaughton with respect to oil and gas reserves of Abraxas. (Filed herewith).

* Management Compensatory Plan or Agreement.

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SIGNATURES

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

ABRAXAS PETROLEUM CORPORATION

By:	/s/Robert L.G. Watson	By:	/s/Barbara M. Stuckey	By:	/s/ G. William Krog, Jr.
	President and Principal Executive Officer		Vice President and Principal Financial Officer		Principal Accounting Officer

DATED: March 15, 2012

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 15, 2012
/s/ Barbara M. Stuckey Barbara M. Stuckey	Vice President, CFO (Principal Financial Officer)	March 15, 2012
/s/ G. William Krog, Jr. G. William Krog, Jr.	Chief Accounting Officer (Principal Accounting Officer)	March 15, 2012
/s/ C. Scott. Bartlett, Jr. C. Scott Bartlett, Jr.	Director	March 15, 2012
/s/ Franklin A. Burke Franklin A. Burke	Director	March 15, 2012
/s/ Harold D. Carter Harold D. Carter	Director	March 15, 2012
/s/ Ralph F. Cox Ralph F. Cox	Director	March 15, 2012
/s/ Dennis E. Logue Dennis E. Logue	Director	March 15, 2012
/s/ Paul A. Powell, Jr. Paul A. Powell, Jr.	Director	March 15, 2012
/s/ Brian L. Melton Brian L. Melton	Director	March 15, 2012
/s/ Edward P. Russell Edward P. Russell	Director	March 15, 2012

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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 related notes thereto.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation as of December 31, 2010 and 2011 and the related consolidated statements of operations and other comprehensive income (loss), stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Abraxas Petroleum Corporation at December 31, 2010 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Abraxas Petroleum Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 15, 2012 expressed an unqualified opinion thereon.

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 USA, LLP

Dallas, Texas
March 15, 2012

Report of Independent Registered Public Accounting Firm

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

We have audited Abraxas Petroleum Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Abraxas Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, "Management's Report on Internal Control Over Financial Reporting". Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Abraxas Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Abraxas Petroleum Corporation as of December 31, 2010 and 2011, and the related consolidated statements of operations and other comprehensive income (loss), stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2011 and our report dated March 15, 2012 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Dallas, Texas
March 15, 2012

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2010	December 31, 2011
	(In thousands)	
Current assets:		
Cash and cash equivalents	$99	$—
Accounts receivable:		
Joint owners	5,145	3,354
Oil and gas production sales	6,958	8,897
Other	642	655
	12,745	12,906
Derivative asset – current	6,941	11,416
Assets held for sale	8,457	—
Other current assets	396	391
Total current assets	28,638	24,713
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	434,858	490,908
Unproved properties excluded from depletion	1,085	1,100
Other property and equipment	11,536	33,783
Total	447,479	525,791
Less accumulated depreciation, depletion, and amortization	(330,231)	(346,239)
Total property and equipment, net	117,248	179,552
Investment in joint venture	24,027	26,215
Deferred financing fees, net	3,494	3,490
Derivative asset – long-term	8,674	6,412
Other assets including marketable securities	828	768
Total assets	$182,909	$241,150

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	December 31, 2010	December 31, 2011
	(In thousands, except number of shares)	
Current liabilities:		
Accounts payable	$23,589	$21,373
Joint interest oil and gas production payable	3,000	5,835
Accrued interest	277	209
Other accrued expenses	779	284
Derivative liability – current	9,742	11,640
Current maturities of long-term debt	152	181
Total current liabilities	37,539	39,522
Long-term debt – less current maturities	140,940	126,258
Derivative liability – long-term	11,672	4,307
Future site restoration	7,734	8,412
Total liabilities	197,885	178,499
Commitments and contingencies (Note 9)		
Stockholders' Equity (Deficit):		
Preferred stock, par value $.01 per share – authorized 1,000,000 shares; -0- shares issued and outstanding	—	—
Common stock, par value $.01 per share – authorized 200,000,000 shares; issued and outstanding 76,427,561 and 92,261,057	764	923
Additional paid-in capital	184,223	248,480
Accumulated deficit	(200,208)	(186,465)
Accumulated other comprehensive income (loss)	245	(287)
Total stockholders' (deficit) equity	(14,976)	62,651
Total liabilities and stockholders' equity (deficit)	$182,909	$241,150

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2010	2011
	(In thousands except per share data)		
Revenues:			
Oil and gas production revenues	$51,829	$58,050	$64,615
Other	7	10	7
	51,836	58,060	64,622
Operating costs and expenses:			
Lease operating	20,265	19,475	21,581
Production taxes	5,803	5,910	5,766
Depreciation, depletion, and amortization	17,886	16,212	16,194
Impairment	—	4,787	—
General and administrative (including stock-based compensation of $1,239, $1,560 and $1,987, respectively)	7,705	8,869	9,433
	51,659	55,253	52,974
Operating income	177	2,807	11,648
Other (income) expense:			
Interest income	(15)	(8)	(7)
Interest expense	11,346	9,106	4,898
Amortization of deferred financing fees	1,326	2,479	1,762
Financing fees	362	—	—
(Gain) loss on derivative contracts - realized	(15,328)	(526)	676
Loss (gain) on derivative contracts – unrealized	27,650	(10,285)	(7,476)
Equity in loss (income) of joint venture	—	473	(2,187)
Other	2,071	(119)	316
	27,412	1,120	(2,018)
(Loss) income from operations before income tax and non-controlling interest	(27,235)	1,687	13,666
Income tax (expense) benefit	(1,290)	79	77
Consolidated net (loss) income	(28,525)	1,766	13,743
Less: Net loss attributable to non-controlling interest	9,745	—	—
Net (loss) income	$(18,780)	$1,766	$13,743
Net (loss) income - per common share - basic	$(0.34)	$0.02	$0.15
Net (loss) income - per common share - diluted	$(0.34)	$0.02	$0.15

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2009	2010	2011
	(In thousands)		
Consolidated net (loss) income	$(28,525)	$1,766	$13,743
Other comprehensive income (loss):			
Change in unrealized value of investments	95	(27)	(76)
Foreign currency translation adjustment	(6)	70	(456)
Other comprehensive income (loss)	89	43	(532)
Comprehensive (loss) income	(28,436)	1,809	13,211
Comprehensive loss attributable to non-controlling interest	9,745	—	—
Comprehensive (loss) income attributable to Abraxas	$(18,691)	$1,809	$13,211

See accompanying notes to consolidated financial statements

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

	Common Stock						
	Shares	Amount	Additional Paid in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income(Loss)	Non-Controlling Interest	Total
Balance at December 31, 2008	49,622,423	$496	$187,243	$(183,194)	$113	$7,093	$11,751
Net loss	—	—	—	(18,780)	—	(9,745)	(28,525)
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	95	—	95
Foreign currency translation adjustment	—	—	—	—	(6)	—	(6)
Stock-based compensation	—	—	1,145	—	—	69	1,214
Partnership distributions	—	—	—	—	—	(2,257)	(2,257)
Partnership units issued	—	—	—	—	—	256	256
Partnership registration cost transferred to expense	—	—	—	—	—	1,385	1,385
Shares issued for compensation	61,954	1	77	—	—	—	78
Stock options exercised	239,002	2	201	—	—	—	203
Merger of Partnership into Abraxas Petroleum	25,847,532	258	(6,014)	—	—	3,199	(2,557)
Restricted stock issued, net of cancellations	460,840	5	(5)	—	—	—	—
Balance at December 31, 2009	76,231,751	762	182,647	(201,974)	202	—	(18,363)
Net income	—	—	—	1,766	—	—	1,766
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	(27)	—	(27)

Foreign currency translation adjustment	—	—	—	—	70	—	70
Stock-based compensation	—	—	1,560	—	—	—	1,560
Shares issued for compensation	11,480	—	24	—	—	—	24
Stock options exercised	163,705	2	67	—	—	—	69
Warrants exercised	15,534	—	—	—	—	—	—
Other	—	—	(75)	—	—	—	(75)
Restricted stock issued, net of cancellations	5,091	—	—	—	—	—	—
Balance December 31, 2010	76,427,561	764	184,223	(200,208)	245	—	(14,976)
Net income	—	—	—	13,743	—	—	13,743
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	(76)	—	(76)
Foreign currency translation adjustment	—	—	—	—	(456)	—	(456)
Stock-based compensation	—	—	1,987	—	—	—	1,987
Shares issuance	15,075,502	151	62,195	—	—	—	62,346
Stock options exercised	371,632	4	79	—	—	—	83
Restricted stock issued, net of cancellations	386,362	4	(4)	—	—	—	—
Balance December 31, 2011	92,261,057	$923	$248,480	$ (186,465)	$ (287)	$ —	$62,651

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2010	2011
		(In thousands)	
Operating Activities			
Net (loss) income	$(28,525)	$1,766	$13,743
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Equity in loss (income) of joint venture	—	473	(2,187)
Change in derivative fair value	25,740	(10,451)	(7,680)
Monetization of derivative contracts	26,736	—	—
Depreciation, depletion, and amortization	17,886	16,212	16,194
Impairment	—	4,787	—
Accretion of future site restoration	558	516	452
Amortization of deferred financing fees	1,326	2,479	1,762
Stock-based compensation	1,239	1,560	1,987
Registration fees previously capitalized	2,210	—	—
Loss on disposal of assets	289	—	—
Other non-cash transactions	78	24	—
Changes in operating assets and liabilities:			
Accounts receivable	(803)	(3,976)	(182)
Other assets and liabilities	(7)	(113)	(17)
Accounts payable	(1,545)	14,210	756
Accrued expenses	(1,046)	(3,385)	(333)
Net cash provided by operating activities	44,136	24,102	24,495
Investing Activities			
Capital expenditures, including purchases and development of properties	(16,471)	(36,448)	(79,012)
Proceeds from the sale of oil and gas properties	2,375	21,400	8,457
Net cash used in investing activities	(14,096)	(15,048)	(70,555)
Financing Activities			
Proceeds from exercise of stock options and warrants	203	69	83
Proceeds from issuance of common stock, net of offering costs	—	—	62,346
Transaction costs on exchange of partnership units	(2,557)	—	—
Proceeds from long-term borrowings	13,500	3,000	50,500
Payments on long-term borrowings	(32,736)	(13,641)	(65,153)
Partnership distribution to non-controlling interest	(2,257)	—	—
Deferred financing fees	(5,687)	(169)	(1,758)
Other	(569)	(75)	(52)
Net cash (used in) provided by financing activities	(30,103)	(10,816)	45,966
Effect of exchange rate changes on cash	—	—	(5)
Decrease in cash	(63)	(1,762)	(99)
Cash at beginning of year	1,924	1,861	99
Cash at end of year	$1,861	$99	$—

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(CONTINUED)

	Years Ended December 31,		
	2009	2010	2011
		(In thousands)	
Supplemental disclosures of cash flow information:			
Interest paid	$10,575	$8,876	$4,514
Non-Cash Investing Activities:			
Asset retirement obligation cost and liabilities	$(80)	$(83)	$(8)
Asset retirement obligations associated with property acquisitions and dispositions	$2	$(2,735)	$306
Properties contributed to joint venture	$—	$24,500	$—

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Significant Accounting Policies

Nature of Operations

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States and Canada. Our oil and gas assets are located in four operating regions in the United States, the Rocky Mountain, Mid-Continent, Permian Basin and onshore Gulf Coast, and in the province of Alberta, Canada.

The terms "Abraxas," "Abraxas Petroleum," "we," "us," "our" or the "Company" refer to Abraxas Petroleum Corporation ar of its subsidiaries, including Raven Drilling LLC ("Raven Drilling") and its wholly-owned foreign subsidiary, Canadian Abraxas Petroleum, ULC ("Canadian Abraxas"). The term "Partnership" refers only to Abraxas Energy Partners, L.P.

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.

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, 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.

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 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.

Canadian Abraxas' assets and liabilities are translated to U.S. dollars at period-end exchange rates. Income and expense items are translated at average rates of exchange prevailing during the period. Translation adjustments are accumulated as a separate component of stockholders' equity.

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Liquidity

The recent global recession had a significant impact on our operations. As a result of the recession, gas prices have been depressed due to the weak demand in the manufacturing industry and the oversupply of natural gas thereby causing a prolonged downturn, which reduced our cash flows from operations through 2011. In the future, if gas prices continue to be weak or if a significant decline in oil prices occurs, it could reduce our 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 (“GAAP”) 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.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and 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 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 $54,000 and $84,000 at December 31, 2010 and 2011, 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 by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues 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. As of December 31, 2009, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves. We did not own any properties outside of the United States in 2009. As of December 31, 2010, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves; however, the net capitalized costs of oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $4.8 million resulting in a write down for the year ended December 31, 2010. As of December 31, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves.

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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 improvements are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Assets Held for Sale

As discussed in Note 4, “Divestiture of Non-Core Properties,” during the fourth quarter of 2009 and throughout 2010, the Company sold certain properties, principally non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. The Company's assets sold late in 2010 are presented separately as "Assets held for sale" in the consolidated balance sheet at December 31, 2010, in accordance with ASC 360. Assets held for sale were recorded at the amount of the sales proceeds with a corresponding reduction to the full cost pool in accordance with full cost accounting rules. Proceeds from this sale were received on February 1, 2011.

Estimates of Proved Oil and Gas Reserves

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

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

Our proved reserve information included in this report was predominately based on studies performed by the operations department of Abraxas and estimated 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 cause material revisions to the estimate.

In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the average 12 month first-day-of-month pricing for the years ended December 31, 2010 and 2011, and costs as of December 31, 2010 and 2011. 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 depreciation, depletion and amortization, or 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 commodity prices, which may make it uneconomic to drill for and produce higher cost fields.

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are 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. 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 derivative instruments to qualify for hedge accounting rules as prescribed by ASC 815. Accordingly, we do not 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 in the current period.

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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 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 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 restricted stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2009, 2010 and 2011, stock-based compensation was approximately $1.2 million, $1.6 million and $2.0 million, respectively. For additional information regarding share-based payments, refer to Note 7, "Stock-based Compensation, Option Plans and Warrants."

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive Federal, provincial, 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 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 we 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 obligations during the three years ended December 31:

	2009	2010	2011
		(In thousands)	
Beginning asset retirement obligation	$9,959	$10,326	$7,734
New wells placed on production and other	91	64	318
Deletions related to property disposals and plugging costs	(282)	(3,172)	(92)
Accretion expense	558	516	452
Ending asset retirement obligation	$10,326	$7,734	$8,412

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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 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, 2009, 2010 and 2011.
During 2009 and 2010, two purchasers accounted for 22% and 21% of oil and gas revenues, respectively. During 2011, three purchasers accounted for 28% of oil and gas revenues.

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 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 be in effect to taxable income in the years in which those temporary differences are expected to be recovered or settled. 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 $83.5 million for deferred tax assets at December 31, 2011.

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.

Other Comprehensive Income (Loss)

ASC 220 requires disclosure of comprehensive income (loss), which includes reported net income (loss) as adjusted for other comprehensive income (loss). Comprehensive income (loss) for the Company is the change in the unrealized value of investments and foreign currency translation adjustments.

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New Accounting Pronouncements

In 2010, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") to address diversity in practice in interpreting the pro forma revenue and earnings disclosure requirements for business combinations. The ASU specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the current year business combination(s) had occurred as of the beginning of the comparable prior annual reporting period. The adoption of this ASU will have no material impact on our consolidated financial statements.

In 2011, the FASB issued two ASUs which amend guidance for the presentation of comprehensive income. The amended guidance requires an entity to present components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive statements. The current option to report other comprehensive income and its components in the statement of stockholders' equity will be eliminated. Although the new guidance changes the presentation of comprehensive income, there are no changes to the components that are recognized in net income or other comprehensive income under existing guidance. These ASUs are effective for us in the first quarter of 2012 and retrospective application will be required. These ASUs will change our financial statement presentation of comprehensive income but will not impact our net income, financial position, or cash flows.

In 2011, the FASB issued an ASU which intended to reduce complexity and costs by allowing an entity the option to make a qualitative evaluation about the likelihood of goodwill impairment to determine whether it should calculate the fair value of a reporting unit. The ASU also expands upon the examples of events and circumstances that an entity should consider between annual impairment tests in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The ASU is effective for us in the first quarter of 2012, with early adoption permitted. The adoption of this ASU will have no impact on our consolidated financial statements.

2. 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, 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.

3. Formation of Joint Venture

On August 18, 2010, Abraxas Petroleum and its wholly-owned subsidiary, Abraxas Operating, LLC, contributed 8,333 net acres in the Eagle Ford Shale play to Blue Eagle Energy, LLC ("Blue Eagle") and received a $25.0 million equity interest in Blue Eagle pursuant to the terms of the Subscription and Contribution Agreement among Abraxas Petroleum, Abraxas Operating, Blue Eagle and Rock Oil Company, LLC ("Rock Oil") formerly known as Blue Stone Oil & Gas, LLC. Simultaneously, Rock Oil contributed $25.0 million in cash to Blue Eagle for a $25.0 million equity interest in Blue Eagle. Rock Oil committed to contribute an additional $50.0 million to Blue Eagle and upon full funding, Abraxas Petroleum would own a 25% equity interest and Rock Oil would own a 75% equity interest.

Blue Eagle's subject area encompasses 12 counties across the Eagle Ford Shale play. Abraxas Petroleum operates the wells owned by Blue Eagle and Rock Oil and Abraxas jointly manage the day-to-day business affairs of Blue Eagle. Robert L. G. Watson, our President and CEO, serves as one of the three members of the Board of Managers of Blue Eagle.

At formation and through June 29, 2011, we owned a non-controlling 50.0% interest in the joint venture. On June 29, 2011, Rock Oil contributed $11.0 million to Blue Eagle to purchase approximately 2,487 net acres in northern McMullen County, Texas, which reduced our equity interest to 41.0%. On October 19, 2011 and December 9, 2011, Rock Oil contributed an additional $3.0 million and $8.0 million, respectively, to Blue Eagle to drill and complete a well in McMullen County, Texas and for general corporate purposes. As of December 31, 2011, we owned a non-controlling 34.7% interest in the joint venture.

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We account for the joint venture under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture is reflected as an increase (decrease) in its investment account in "Investment in joint venture" and is also recorded as equity investment income (loss) in "Equity in loss (income) of joint venture." For the years ended December 31, 2010 and 2011, we incurred a loss of $473,000 and income of $2.2 million, respectively.

The following is condensed financial data from Blue Eagle's December 31, 2010 and 2011 financial statements:

Balance Sheet:	As of December 31, 2010	As of December 31, 2011
Assets:	(In thousands)	
Current assets	$19,625	$11,910
Oil and gas properties	31,753	66,663
Other assets	45	36
Total assets	$51,423	$78,609
Liabilities and Members' Capital:		
Current liabilities	$3,368	$3,070
Other liabilities	—	41
Members' capital	48,055	75,498
Total liabilities and members' capital	$51,423	$78,609

Statement of Operations:	For the period August 18, 2010 (inception) through December 31, 2010	Year Ended December 31, 2011
	(In thousands)	
Revenue	$—	$12,579
Operating expenses	682	7,138
Other expense (income)	263	(11)
Net (loss) income	$(945)	$5,452

4. Divestiture of Non-Core Properties

In the fourth quarter of 2009 and throughout 2010, we sold certain properties non-core assets in nine different states for combined net proceeds of approximately $32.2 million ($2.4 million in 2009 and $29.8 million in 2010, of which $8.4 million was received in February 2011) at various property auctions to numerous buyers. The net proceeds were used to repay outstanding indebtedness under our credit facility, for capital expenditures and general corporate purposes.

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5. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2010 and 2011, respectively:

	December 31, 2010	December 31, 2011
	(In thousands)	
Senior secured credit facility	$136,000	$115,000
Rig loan agreement	—	6,500
Real estate lien note	5,092	4,939
	141,092	126,439
Less current maturities	(152)	(181)
	$140,940	$126,258

Maturities of long-term debt are as follows:

Year ending December 31,	(In thousands)
2012	$181
2013	1,089
2014	1,440
2015	120,651
2016	1,336
Thereafter	1,742
	$126,439

Credit Facility

On June 30, 2011, we entered into a second 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. As of December 31, 2011, $115.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $125.0 million and is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced 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 $125.0 million was determined based upon our reserve report dated June 30, 2011. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under 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) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At December 31, 2011, the interest rate on the credit facility was 3.53% based on 1-month LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR 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. Neither the properties owned by Blue Eagle nor our investment in Blue Eagle is used to secure the credit facility.

Each of our subsidiaries 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, other than Raven Drilling.

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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 4.00 to 1.00. 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 a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20, and any accounts receivable from Blue Eagle 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, and any accounts payable to Blue Eagle. 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. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts 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; provided that net income shall be adjusted to negate the effect of non-cash gain or loss attributable to Blue Eagle. 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. 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.

At December 31, 2011, we were not in compliance with the financial ratio that we maintain a current ratio, as of the last day of each quarter, of not less than 1.00 to 1.00, as defined. As of December 31, 2011, the current ratio was 0.81 to 1.00. We have received a waiver from our lenders for the quarter ended December 31,2011 with respect to this covenant breach. . Though we anticipate that the results of our operations combined with the monetization of our gas derivative contracts, which was completed on March 12, 2012, will allow us to remain in compliance with these covenants through the remainder of 2012, we will consider other actions such as sales of non-core assets if necessary. As of December 31, 2011, the interest coverage ratio was 4.61 to 1.00 and the total debt to EBITDAX ratio was 3.90 to 1.00.

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.

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Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2000 hp diesel electric drilling rig (the "Collateral"). The rig loan agreement provides for interim borrowings payable to Raven Drilling or certain vendors on behalf of Raven Drilling until the final amount of the loan is determined. The rig loan agreement further provides for multiple notes in quantities of not less than $100,000 each with a maximum total of $7.0 million. Outstanding amounts under the interim borrowings will bear interest at LIBOR plus 3.50% and outstanding amounts under each note will bear interest at the four-year interest swap rate, published by the Federal Reserve, plus 3.50%, as determined at closing of each note. Upon closing of each note, interest only is due for the first 18-months (approximately) and thereafter, each note will amortize in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note will be 60 months after the closing of the note. At December 31, 2011, the interest rate on the rig loan agreement was 3.80% based on 1-month LIBOR borrowings.

As of December 31, 2011, $6.5 million was outstanding under the rig loan agreement. On February 14, 2012, Raven finalized the note with respect to the rig loan agreement. The principal amount of the note is $7.0 million and bears interest at 4.26%, which equates to the four-year interest swap rate plus 3.50% on the date of closing. Interest only is due for the first 18-months of the note and will amortize in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017.

Abraxas Petroleum has guaranteed Raven Drilling's obligations under the rig loan agreement and associated notes. Obligations under the rig loan agreement are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in the Collateral.

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 5.25% and is payable in monthly installments of principal and interest of $36,652 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, 2011, $4.9 million was outstanding on the note.

6. Property and Equipment

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

	Estimated Useful Life Years	December 31, 2010	December 31, 2011
		(In thousands)	
Oil and gas properties	—	$435,943	$492,008
Equipment and other	3-39	11,536	16,330
Drilling rig	(1)	—	17,453
		$447,479	$525,791

(1) Not yet in service, includes capitalized interest of $205,034

7. Stock-based Compensation, Option Plans and Warrants

Stock Options

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. The fair value for these options was estimated at the date of grant using the following weighted average assumptions for 2009, 2010 and 2011:

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	2009	2010	2011
Weighted average value per option granted during the period	$1.41	$1.61	$3.11
Assumptions: (1)(2)			
Expected dividend yield	0 %	0 %	0 %
Volatility	83.0 %	84.0 %	80.0 %
Risk free interest rate	2.48 %	2.87 %	2.21 %
Expected life (years)	6.1 years	9.0 years	6.4 years
Fair value of options granted (in thousands)	$2,195	$1,553	$2,506

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(1) The estimated future forfeiture rate is based on the Company's historical forfeiture rate.

(2) The Company does not pay dividends on its common stock.

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

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 of the Company's board of directors. 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.

The following table is a summary of the Company's stock option activity for the three years ended December 31, 2011:

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Fair value per share
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		
Granted	964	2.12		
Exercised	(213)	0.89		
Forfeited/Expired	(21)	2.93		
Options outstanding December 31, 2010	4,820	$ 2.23		
Granted	807	4.37		
Exercised	(530)	1.54		
Forfeited/Expired	(341)	3.01		
Options outstanding December 31, 2011	4,756	$ 2.61	6.9 years	$ 2.61

Exercisable at end of year	2,512	5.7 years	$ 2.71

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Other information pertaining to the Company's stock option activity for the three years ended December 31, 2011:

	2009	2010	2011
Weighted average grant date fair value of stock options granted (per share)	$1.01	$1.61	$3.11
Total fair value of options vested (000's)	$801	$949	$1,230
Total intrinsic value of options exercised (000's)	$155	$373	$1,584

As of December 31, 2011, the total compensation cost related to non-vested awards not yet recognized was approximately $3.1 million, which will be recognized in 2012 through 2015. For the year ended December 31, 2011, we recognized $1.5 million in stock-based compensation expense relating to options.

The following table represents the range of stock option prices and the weighted average remaining life of outstanding options as of December 31, 2011:

	Options outstanding			Exercisable		
	Number outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable	Weighted average remaining life	Weighted average exercise price
$0.50 – 0.99	983,000	5.75	$0.91	567,000	4.68	$0.86
$1.00 – 1.99	1,154,129	7.52	$1.68	596,972	7.29	$1.62
$2.00 – 2.99	875,225	7.90	$2.17	289,292	7.27	$2.31
$3.00 – 3.99	441,401	7.51	$3.59	232,526	5.68	$3.60
$4.00 – 4.99	1,223,500	6.49	$4.59	747,000	4.75	$4.51
$5.00 – 6.05	79,000	4.15	$6.05	79,000	4.15	$6.05
	4,756,255			2,511,790		

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. For the year ended December 31, 2011, we recognized $482,000 in stock-based compensation expense related to restricted stock awards.

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The following table is a summary of the Company's restricted stock activity for the three years ended December 31, 2011:

	Number of Shares	Weighted average grant date fair value
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
Granted	20,000	2.45
Vested/Released	(155,268)	2.22
Forfeited	(13,345)	1.85
Unvested December 31, 2010	400,295	$ 2.02
Granted	408,676	3.67
Vested/Released	(156,890)	2.24
Forfeited	(22,310)	2.27
Unvested December 31, 2011	629,771	$ 3.03

Restricted Unit Awards

Restricted unit awards were awards of Partnership units that were subject to restrictions on transfer and to a risk of forfeiture if the awardee terminated employment with the Company prior to the lapse of the restrictions. The value of such unit was determined using the implied market price on the grant date. The implied market price was determined by comparing the average trading yields of comparable publicly-traded master limited partnerships to the distribution paid or declared by the Partnership prior to the grant date. Compensation expense was 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. No equity-based compensation was incurred for the years ended December 31, 2010 or 2011. In connection with the closing of the Merger, restricted unit awards were converted into restricted stock awards of the Company. (See Note 2. "Merger".)

Phantom Units

On January 31, 2008, in connection with the closing of an acquisition of properties, 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.

For the year ended December 31, 2009, the Partnership incurred equity-based compensation expense of $25,000, 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. "Merger".)

Director Stock Awards

Shares Reserved and Awards. The 2005 Directors Plan (as amended) reserves 1.5 million shares of Abraxas common stock, subject to adjustment following certain events. 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 10,500 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 100,000 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise 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 10,500 shares or options and prior to April 2010, directors were compensated $20,000 per year, $12,000 of which was paid quarterly by issuance of common stock and the remaining $8,000 was paid quarterly in cash. During 2009 and 2010, there were 61,954 and 11,480 shares issued, respectively, related to this compensation. The number of shares issued was determined based on the stock price on the date of issuance. Between April 2010 and April 2011, directors were compensated for their annual retainer fee of $26,000 in cash, which increased to $27,500 in April 2011.

At December 31, 2011, the Company had approximately 6.2 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. The warrants expire on May 25, 2012 and are exercisable at a price of $3.83 per share, subject to certain adjustments. 114,230 warrants were exercised in 2010, however, no warrants were exercised in 2009 or 2011.

8. Income Taxes

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

	Years Ended December 31,		
	2009	2010	2011
	(In thousands)		
Deferred tax liabilities:			
Marketable securities	$67	$57	$36
Canada full cost pool	—	—	377
Investment in Blue Eagle	—	7,107	7,527
Hedge contracts	—	—	345
Total deferred tax liabilities	67	7,164	8,285
Deferred tax assets:			
U.S. full cost pool	37,360	37,464	29,976
Canada full cost pool	—	1,238	—
Depletion carryforward	4,421	4,667	4,842
U.S. net operating loss carryforward	42,583	49,621	52,564
Canada net operating loss carryforward	—	301	2,151
Alternative minimum tax credit	503	422	422
Hedge contracts	3,798	1,904	—
Other	2,890	3,447	1,811
Total deferred tax assets	91,555	99,064	91,766
Valuation allowance for deferred tax assets	(91,488)	(91,900)	(83,481)
Net deferred tax assets	67	7,164	8,285
Net deferred tax	$—	$—	$—

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

	Years ended December 31, 2009	2010	2011
	(In thousands)		
Current:			
Federal	$425	$—	$(77)
State	865	(79)	—
Foreign	—	—	—
	$1,290	$(79)	$(77)
Deferred:			
Federal	$—	$—	$—
Foreign	—	—	—
	$—	$—	$—

At December 31, 2011, the Company had, subject to the limitation discussed below, $150.2 million of net operating loss carryforwards for U.S. tax purposes, and $7.7 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire in varying amounts through 2031 and the Canadian loss carryforward will expire in 2031, 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 ASC 740-10. Therefore, the Company has established a valuation allowance of $91.5 million at December 31, 2009, $91.9 million at December 31, 2010 and $83.5 million at December 31, 2011.

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

	Years ended December 31, 2009	2010	2011
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	$6,121	$(591)	$(4,809)
(Increase) decrease in deferred tax asset valuation allowance	(30,725)	(412)	5,408
Basis difference in hedge liability	—	1,890	—
Rate differential for non U.S. income	—	(385)	(46)
State income taxes	(562)	—	—
Permanent differences	(4)	(409)	(533)
Increase in asset basis for Merger	23,986	—	—
Other	(106)	(14)	57
	$(1,290)	$79	$77

During 2011, the Company reduced deferred tax assets by $3.0 million related to stock award plans, the full cost pool assets and the net operating loss carryforward. The deferred tax assets were fully offset by a valuation allowance which was reduced at the same time.

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 for the year ended December 31, 2011. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2011, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly-owned subsidiary of Abraxas, are currently undergoing an Internal Revenue Service audit of their 2009 Federal income tax returns.

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9. Commitments and Contingencies

Operating Leases

In September 2009, the Company leased office space in Calgary, Alberta. During 2010 and 2011, rent expense of $91,528 CN ($88,511 USD) and $102,453 CN ($121,500 USD), respectively, was incurred related to this lease. In July 2011, the Company leased office space in Dickinson, North Dakota. During 2011, rent expense of $9,250 was incurred related to this lease. This lease expires on August 31, 2012.

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, 2011, 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.

10. Earnings per Share

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

	Years ended December 31:		
	2009	2010	2011
	(In thousands, except per share data)		
Numerator:			
Net (loss) income	$(18,780)	$1,766	$13,743
Denominator:			
Denominator for basic earnings per share – weighted-average common shares outstanding	55,499	75,923	90,151
Effect of dilutive securities:			
Stock options, restricted shares and warrants	—	1,301	2,093
Dilutive potential common shares:			
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options, restricted shares and warrants	55,499	77,224	92,244
Net (loss) income per common share – basic	$(0.34)	$0.02	$0.15
Net (loss) income per common share – diluted	$(0.34)	$0.02	$0.15

Basic earnings per share, excluding any dilutive effects of stock options, warrants and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities. For the year ended December 31, 2009, 310,692 potential shares relating to stock options were excluded from the calculation of diluted income (loss) per share since their inclusion would have been anti-dilutive due to the loss incurred in the period.

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11. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2010 and 2011 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2010				
Net revenue	$ 15,865	$ 14,651	$ 13,710	$ 13,834
Operating income (loss)	$ 3,258	$ 1,527	$ 1,273	$ (3,251)
Net income (loss)	$ 11,183	$ 5,300	$ (856)	$ (13,861)
Net income (loss) per common share – basic	$ 0.15	$ 0.07	$ (0.01)	$ (0.18)
Net income (loss) per common share – diluted	$ 0.15	$ 0.07	$ (0.01)	$ (0.18)
Year Ended December 31, 2011				
Net revenue	$ 13,847	$ 16,656	$ 17,666	$ 16,453
Operating income	$ 2,503	$ 3,438	$ 4,225	$ 1,482
Net (loss) income	$ (10,019)	$ 8,937	$ 20,085	$ (5,260)
Net (loss) income per common share – basic	$ (0.12)	$ 0.10	$ 0.22	$ (0.06)
Net (loss) income per common share – diluted	$ (0.12)	$ 0.10	$ 0.21	$ (0.06)

12. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees. In 2009, 2010 and 2011, in accordance with the safe harbor provisions of the plan, the Company contributed $157,436, $177,817 and $226,377, respectively, to the plan. The Company adopted the safe harbor provisions for its 401(k) plan which requires us to contribute a fixed match to each participating employee’s contribution to the plan. The fixed match is set at the rate of dollar for dollar on the first 1% of eligible pay contributed, then 50 cents on the dollar for each additional percentage point of eligible pay contributed, up to 5%. Employee’s eligible pay with respect to calculating the fixed match is limited by IRS regulations. In addition, the Board of Directors, at its sole discretion, may authorize the Company to make additional contributions to each participating employee’s plan. The employee contribution limit for 2009, 2010 and 2011 was $16,500 for employees under the age of 50 and $22,000 for employees 50 years of age or older.

13. Business Segments

The Company has operations in only one industry segment, the oil and gas exploration and production industry; however, beginning in 2010, the Company was organizationally structured along geographic operating segments or regions. The Company has reportable operations in the United States and Canada.

In 2011, three customers accounted for approximately 28% of our consolidated oil and natural gas production revenue. Two customers accounted for approximately 26% of United States revenue and one customer accounted for

100% of revenue in Canada.

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The following tables provide the Company's geographic operating segment data as of and for the year ended December 31, 2010 and 2011:

	Year Ended December 31, 2010			
	U.S.	Canada	Corporate	Total
	(In thousands)			
Revenues:				
Oil and gas production	$57,990	$60	$—	$58,050
Other	—	—	10	10
	57,990	60	10	58,060
Costs and expenses:				
Lease operating	19,460	16	—	19,475
Production taxes	5,909	—	—	5,910
Depreciation, depletion and amortization	15,603	66	543	16,212
Impairment	—	4,787	—	4,787
General and administrative	1,635	688	6,546	8,869
Net interest	—	—	9,098	9,098
Amortization of deferred financing fees	—	—	2,479	2,479
Equity in loss of joint venture	—	—	473	473
Other	—	—	(11,009)	(11,009)
Income (loss) from operations	$15,383	$(5,497)	$(8,120)	$1,766

	Year Ended December 31, 2011			
	U.S.	Canada	Corporate	Total
	(In thousands)			
Revenues:				
Oil and gas production	$63,105	$1,510	$—	$64,615
Other	—	—	7	7
	63,105	1,510	7	64,622
Costs and expenses:				
Lease operating	20,788	793	—	21,581
Production taxes	5,764	2	—	5,766
Depreciation, depletion and amortization	15,236	709	249	16,194
General and administrative	1,698	654	7,081	9,433
Net interest	448	4	4,439	4,891
Amortization of deferred financing fees	—	—	1,762	1,762
Equity in (income) of joint venture	—	—	(2,187)	(2,187)
Other	—	—	(6,561)	(6,561)
Income (loss) from operations	$19,171	$(652)	$(4,776)	$13,743

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The following table provides the Company's geographic asset data as of December 31, 2010 and December 31, 2011:

Segment Assets:	December 31, 2010	December 31, 2011
	(In thousands)	
United States	$152,599	$167,739
Canada	4,393	19,379
Corporate	25,917	54,032
	$182,909	$241,150

14. 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. Our derivative contracts 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.

The following table sets forth our derivative contracts as of December 31, 2011:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
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 for $100 million at a fixed rate of 3.367% originally expired 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, 2010		December 31, 2011	
	(In thousands)			
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX-based fixed price derivative contracts	Derivative asset - current	$6,941	Derivative asset - current	$11,416
NYMEX-based fixed price derivative contracts	Derivative asset – long-term	$8,674	Derivative asset – long-term	$6,412
NYMEX-based fixed price derivative contracts	Derivative liability - current	$6,394	Derivative liability - current	$10,094

NYMEX-based fixed price derivative contracts	Derivative liability – long-term	$11,672	Derivative liability – long-term	$4,307
Interest rate swap	Derivative liability - current	$3,348	Derivative liability - current	$1,546

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

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15. Financial Instruments

Effective January 1, 2008, the Company adopted ASC 820-10 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 ASC 820-10 did not cause a change in the method of calculating fair value of our assets or liabilities, with the exception of incorporating a measure of the Company's own non-performance risk or that of its counter-parties, as appropriate, which was not material. The primary impact from adoption was additional disclosures.

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 sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2010 and 2011, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2010
Assets:				
Investment in common stock	$181	$—	$ —	$181
NYMEX Fixed Price Derivative contracts	—	15,615	—	15,615
Total Assets	$181	$15,615	$ —	$15,796
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$18,066	$ —	$18,066
Interest Rate Swaps	—	—	3,348	3,348
Total Liabilities	$—	$18,066	$ 3,348	$21,414

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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, 2011
Assets:				
Investment in common stock	$104	$—	$ —	$104
NYMEX Fixed Price Derivative contracts	—	17,828	—	17,828
Total Assets	$104	$17,828	$ —	$17,932
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$14,401	$ —	$14,401
Interest Rate Swaps	—	—	1,546	1,546
Total Liabilities	$—	$14,401	$ 1,546	$15,947

The Company has an investment in Insigna Energy Ltd, the surviving entity in the merger with 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, 2011 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. 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 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 for $100 million at a fixed rate of 3.367% originally expired 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. 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) for the three years ended December 31, 2011 is as follows (in thousands):

	Derivative Assets (Liabilities) - net
Balance December 31, 2009	$ (2,256)
Total realized and unrealized losses included in change in net liability	(3,402)
Settlements during the period	2,310
Balance December 31, 2010	(3,348)
Total realized and unrealized losses included in change in net liability	(565)
Settlements during the period	2,367

Balance December 31, 2011	$ (1,546)

16. 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. See Note 2 "Merger."

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17. 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:

	Years Ended December 31					
	2010			2011		
	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)					
Proved oil and gas properties	$434,858	$427,337	$7,521	$490,908	$468,218	$22,690
Unproved properties	1,085	—	1,085	1,100	—	1,100
Total	435,943	427,337	8,606	492,008	468,218	23,790
Accumulated depreciation, depletion, amortization and impairment	(325,793)	(320,957)	(4,836)	(341,264)	(335,871)	(5,393)
Net capitalized costs	$110,150	$106,380	$3,770	$150,744	$132,347	$18,397

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

	Years Ended December 31								
	2009			2010			2011		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Development costs	$15,356	$15,356	$—	$31,278	$23,757	$7,521	$46,735	$32,471	$14,264
Exploration costs	795	795	—	3,809	3,809	—	8,410	8,410	—
Property acquisition costs:									
Unproved	—	—	—	1,085	—	1,085	1,100	—	1,100
	$16,151	$16,151	$—	$36,172	$27,566	$8,606	$56,245	$40,881	$15,364

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The results of operations for oil and gas producing activities for the three years ended December 31, 2009, 2010 and 2011 are as follows:

	Years Ended December 31,								
	2009			2010			2011		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Revenues	$51,829	$51,829	$—	$58,050	$57,990	$60	$64,615	$63,105	$1,510
Production costs	(26,224)	(26,224)	—	(25,790)	(25,774)	(16)	(27,347)	(26,552)	(795)
Depreciation, depletion, and amortization	(17,361)	(17,361)	—	(15,653)	(15,603)	(50)	(15,595)	(14,914)	(681)
Proved property impairment	—	—	—	(4,787)	—	(4,787)	—	—	—
General and administrative	(1,617)	(1,617)	—	(2,323)	(1,635)	(688)	(2,352)	(1,698)	(654)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$6,627	$6,627	$—	$9,497	$14,978	$(5,481)	$19,321	$19,941	$(620)
Depletion rate per barrel of oil equivalent	$10.63	$10.63	$—	$11.00	$10.98	$59.97	$12.26	$11.96	$27.58

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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, 2009, 2010, and 2011. 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 and Canada.

Proved reserves were estimated in accordance with guidelines established by the SEC 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-first-day-of-the-month commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows for the periods presented.

	Total			United States (In thousands)			Canada		
	Oil/NGL (MBbl)	Gas (MMcf)	Oil Equivalents (MBoe)	Oil/NGL (MBbl)	Gas (MMcf)	Oil Equivalents (MBoe)	Oil/NGL (MBbl)	Gas (MMcf)	Oil Equivalents (MBoe)
Proved developed and undeveloped reserves:									
Balance at December 31, 2008	7,045	108,416	25,114	7,045	108,416	25,114	—	—	—
Revisions of previous estimates	193	(14,652)	(2,249)	193	(14,652)	(2,249)	—	—	—
Extensions and discoveries	2,173	9,090	3,688	2,173	9,090	3,688	—	—	—
Production	(579)	(6,329)	(1,634)	(579)	(6,329)	(1,634)	—	—	—
Balance at December 31, 2009	8,832	96,525	24,919	8,832	96,525	24,919	—	—	—
Revisions of previous estimates	1,067	729	1,189	1,067	729	1,189	—	—	—
Extensions and discoveries	1,329	1,456	1,572	1,252	1,066	1,430	77	390	142
Sales of minerals in place	(925)	(8,318)	(2,311)	(925)	(8,318)	(2,311)	—	—	—
Production	(509)	(5,479)	(1,422)	(508)	(5,479)	(1,421)	(1)	—	(1)

Balance at December 31, 2010	9,794	84,913	23,947	9,718	84,523	23,806	76	390	141
Revisions of previous estimates	2,290	(13,009)	122	2,290	(13,009)	122	—	—	—
Extensions and discoveries	2,703	4,393	3,435	2,326	1,837	2,632	377	2,556	803
Production	(568)	(4,222)	(1,272)	(554)	(4,160)	(1,247)	(14)	(62)	(25)
Balance at December 31, 2011	14,219	72,075	26,232	13,780	69,191	25,313	439	2,884	919

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	Total			United States			Canada		
	Oil/NGL (MBbl)	Gas (MMcf)	Oil Equivalents (MBoe)	Oil/NGL (MBbl)	Gas (MMcf)	Oil Equivalents (MBoe)	Oil/NGL (MBbl)	Gas (MMcf)	Oil Equivalents (MBoe)
					(In thousands)				
Proved Developed Reserves:									
December 31, 2009	5,891	47,861	13,868	5,891	47,861	13,868	—	—	—
December 31, 2010	5,862	42,750	12,987	5,786	42,360	12,846	76	390	141
December 31, 2011	7,761	42,582	14,858	7,433	40,451	14,175	328	2,131	683
Proved Undeveloped Reserves:									
December 31, 2009	2,941	48,665	11,052	2,941	48,665	11,052	—	—	—
December 31, 2010	3,932	42,163	10,959	3,932	42,163	10,959	—	—	—
December 31, 2011	6,460	29,493	11,376	6,348	28,740	11,138	112	753	238

Reserve extensions and discoveries which increased significantly during 2009 and 2011 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 play in which we have offsetting leasehold together with our own activity in the basin. Revisions of previous estimates which decreased appreciably during 2009 and 2011 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.

Sales of minerals in place increased significantly during 2010, which were attributable to the sale of certain properties, principally non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program.

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The following table contains information relating to proved reserves attributable to Abraxas' equity interest in Blue Eagle as of December 31, 2010 and 2011. All of Blue Eagle's reserves are in the United States.

	Oil/NGL (MBbl)	Total Gas (MMcf) (in thousands)	Oil Equivalents (MBoe)
Proved developed and undeveloped reserves:			
Balance at December 31, 2009	—	—	—
Extensions and discoveries	1,239	8,301	2,623
Balance at December 31, 2010	1,239	8,301	2,623
Decrease in equity interest	(373)	(2,501)	(772)
Revisions of previous estimates	9	854	151
Extensions and discoveries	473	2,688	921
Production	(55)	(353)	(132)
Balance at December 31, 2011	1,293	8,989	2,791
Proved Developed Reserves:			
December 31, 2010	—	—	—
December 31, 2011	202	1,339	425
Proved Undeveloped Reserves:			
December 31, 2010	1,239	8,301	2,623
December 31, 2011	1,091	7,648	2,366

At formation and through June 29, 2011, we owned a non-controlling 50.0% interest in the joint venture. On June 29, 2011, Rock Oil contributed $11.0 million to Blue Eagle which reduced our equity interest to 41.0%. On October 19, 2011 and December 9, 2011, Rock Oil contributed an additional $3.0 million and $8.0 million, respectively, to Blue Eagle which reduced our equity interest to 34.7%. As of December 31, 2011, we owned a non-controlling 34.7% interest in the joint venture.

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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, 2009, 2010 and 2011. The following information has been prepared in accordance with SEC rules and accounting standards based on the 12-month first-day-of-the-month average prices 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 to be based on the twelve month average, first-day-of-the-month price beginning with the year ended December 31, 2009. 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. Since prices used in the calculation are average prices for 2011, the standardized measure could vary significantly from year to year based on the market conditions that occurred during a given year.

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. All reports by DeGolyer and MacNaughton were developed utilizing studies performed by the operations department of Abraxas and estimated by independent petroleum engineers. The report of DeGolyer and MacNaughton dated February 21, 2012, 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, 2010 and 2011 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 26 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.

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Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure. The table below sets forth the Standardized Measure of our proved oil and gas reserves for the three years ended December 31, 2009, 2010 and 2011:

	Years Ended December 31,								
	2009			2010			2011		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Future cash inflows	$816,436	$816,436	$—	$1,020,286	$1,012,829	$7,457	$1,471,352	$1,420,013	$51,339
Future production costs	(332,283)	(332,283)	—	(391,396)	(389,395)	(2,001)	(544,970)	(532,056)	(12,914)
Future development costs	(138,354)	(138,354)	—	(164,135)	(163,085)	(1,050)	(228,804)	(224,254)	(4,550)
Future income tax expense	—	—	—	—	—	—	(106,839)	(104,279)	(2,560)
Future net cash flows	345,799	345,799	—	464,755	460,349	4,406	590,739	559,4248	31,315
Discount	(195,270)	(195,270)	—	(267,762)	(266,041)	(1,721)	(321,657)	(310,516)	(11,141)
Standardized Measure of discounted future net cash relating to proved reserves	$150,529	$150,529	$—	$196,993	$194,308	$2,685	$269,082	$248,908	$20,174

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Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure. The table below sets forth the Standardized Measure of our proved oil and gas reserves attributable to Abraxas' equity interest in Blue Eagle for the two years ended December 31, 2010 and 2011:

	Years Ended December 31,	
	2010	2011
	(In thousands)	
Future cash inflows	$95,378	$120,913
Future production costs	(13,750)	(19,630)
Future development costs	(26,706)	(29,472)
Future income tax expense	(15,862)	(17,996)
Future net cash flows	39,060	53,815
Discount	(23,114)	(32,524)
Standardized Measure of discounted future net cash relating to proved reserves	$15,946	$21,291

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,		
	2009	2010	2011
	(In thousands)		
Standardized Measure, beginning of year	$151,992	$150,529	$196,993
Sales and transfers of oil and gas produced, net of production costs	(25,605)	(32,261)	(37,171)
Net change in prices and development and production costs from prior year	(4,883)	70,311	92,886
Extensions, discoveries, and improved recovery, less related costs	22,267	14,508	47,765
Sales of minerals in place	—	(18,868)	—
Revisions of previous quantity estimates	(13,578)	9,694	1,329
Change in timing and other	5,137	(11,973)	(23,501)
Change in future income tax expense	—	—	(28,918)
Accretion of discount	15,199	15,053	19,699
Standardized Measure, end of year	$150,529	$196,993	$269,082

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,		
	2009	2010	2011
Oil (per Bbl) (1)	$61.18	$79.43	$96.19
Gas (per MMbtu) (2)	4.19	4.45	4.16
Oil (per Bbl) (3)	55.05	70.72	88.58
Gas (per MMBtu) (4)	3.42	3.91	3.73
NGL's (per Bbl) (5)	—	55.60	50.21

(1) The quoted oil price for the year ended December 31, 2009, 2010 and 2011 is the 12-month average first-day-of-the-month West Texas Intermediate spot price for each month of 2009, 2010 and 2011.

(2) The quoted gas price for the year ended December 31, 2009, 2010 and 2011 is the 12-month average first-day-of-the-month Henry Hub spot price for each month of 200920, 2010 and 2011.

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(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.

(5) The NGL price is the realized price as of December 31 of each year after the appropriate differentials have been applied.

The following is an analysis of the changes in the Standardized Measure as it relates to Abraxas' equity interest in Blue Eagle as of December 31, 2010 and 2011. All of Blue Eagle's reserves are in the United States.

	2010	2011
	(In thousands)	
Standardized Measure, beginning of year	$—	$15,946
Sales and transfers of oil and gas produced, net of production costs	—	(4,387)
Net change in prices and development and production costs from prior year	—	6,667
Extensions, discoveries, and improved recovery, less related costs	22,421	6,701
Revisions of previous quantity estimates	—	1,332
Change in equity interest	—	(6,491)
Change in future income tax expense	(6,475)	(646)
Change in timing and other	—	613
Accretion of discount	—	1,556
Standardized Measure, end of year	$15,946	$21,291

Note 18. Subsequent event

On March 12, 2012, we monetized our gas derivative contacts for $12.4 million. Simultaneously, we entered into new oil commodity swaps on as summarized below.

The following table sets forth our oil derivative contract position related to the new swap agreements:

Contract Period	Daily Volume (Bbl)		Swap Price
2012	228	(1)	$ 108.42
2013	289		$ 105.61
2014	840	(2)	$ 100.71

1. For the months of July through December 2012.
2. For the months of January through August 2014.

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10.8	Employment Agreement between Abraxas and Barbara M. Stuckey (Filed herewith).
10.9	Employment Agreement between Abraxas and G. William Krog, Jr. (Filed herewith).
21.1	Subsidiaries of Abraxas
23.1	Consent of BDO USA, 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 with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).
99.2	Report of DeGolyer and MacNaughton with respect to oil and reserves of Blue Eagle (Filed herewith).