ABRAXAS

2010 Annual Report

Letter to Stockholders
Proxy Statement
Form 10-K

LETTER TO OUR STOCKHOLDERS

It gives me great pleasure to write this year's letter and discuss the initial results of the projects that I discussed in last year's letter. 2010 was a year in which we successfully integrated our former master limited partnership into the parent corporation and we divested a large number of non-core, principally non-operated gas properties in the Mid-Continent region. The divested properties reduced our gross well count by approximately one-third and represented approximately 2.3 million barrels of oil equivalent reserves. The net proceeds of $32.2 million were used to pay down debt as well as accelerate our drilling program.

In two of the country's more active and exciting oil resource plays, the Bakken and the Eagle Ford, we have announced the initial results from our operated wells, and we have taken steps toward a third oil resource play, the Niobrara, in the southern Powder River Basin. In the Alberta Basin Bakken play in northwest Montana, we have accumulated a front runner acreage position and we have been successful in our conventional, legacy oil plays in South and West Texas.

The Bakken/Three Forks play in the Williston Basin, located in northwestern North Dakota and northeastern Montana, represents one of the most significant and exciting oil resource plays in the United States since Prudhoe Bay in Alaska in the early 1970's. The play is not without its challenges—the activity level is so high, critical shortages for experienced crews and equipment is occurring and services costs are hyper-inflated. Fortunately for Abraxas, most of our leasehold of approximately 21,000 net acres is held by production giving us the opportunity to wait for more efficient times without losing our leases due to expirations. Despite the challenges, we drilled our first two operated horizontal wells in the play in 2010. The Ravin 26-35 1H, located in McKenzie County, North Dakota, was drilled to a total depth of 20,835 feet, including an approximate 9,800 foot lateral in the Three Forks formation, and completed with a 25 stage frac. After five weeks of restricted flow, the well was opened up and flowed approximately 1,705 barrels of oil equivalent per day, which was comprised of 1,008 barrels of crude oil, 290 barrels of natural gas liquids and 2.4 million cubic feet of wellhead gas. Through the middle of March, the well had produced over 40,000 barrels of oil equivalent during its first three months of production. This well is one of the best in the area to-date and impactful to us as we own an approximate 60% working interest. Our second operated well, the Stenehjem 27-34 1H, also located in McKenzie County, North Dakota, was drilled to a total depth of 16,504 feet, including an approximate 5,965 foot lateral in the Bakken formation, and (as of this writing) waiting on a multi-stage frac. We own an approximate 79% working interest in this well; therefore, it is another impactful well for us. In addition to the operated wells we drilled in 2010, we participated for relatively small working interests in an additional 10 gross wells across the play. Going forward, the level of our operated activity in the play will be dictated by the availability of services on an economic and efficient basis. At the time of this writing, six non-operated Bakken/Three Forks wells were in the process of drilling or completing and one additional non-operated well is waiting on a rig. In addition, we recently elected to participate in the drilling of two horizontal wells targeting the Red River formation and one horizontal well targeting the Mission Canyon formation in the Williston Basin.

The Eagle Ford Shale play in South Texas is rivaling the Bakken for first place as the emerging oil resource play in the country today. We were fortunate to have had some legacy acreage in the heart of the play by virtue of our horizontal Edwards development over the past 15 years and before acreage prices went sky high, we supplemented our legacy position with the acquisition of additional acreage in the play. In August 2010, we closed a joint venture (Blue Eagle Energy, LLC) with Rock Oil Company, LLC, a Denver based private company, to develop our Eagle Ford acreage. At formation, we contributed our existing acreage (8,333 net acres) and Rock Oil contributed $25 million in cash. Our equity interest in the JV is currently 50%. Rock Oil has committed an additional $50 million in cash to the JV, at which time our equity interest would be reduced to 25%. We, as operator of the JV's properties, drilled the first well, the T-Bird 1H, located in DeWitt County, Texas, to a total depth of 19,450 feet, including an approximate 5,700 foot lateral, and completed with a 15 stage frac. The well was placed on production in late January at a restricted rate of approximately 5.8 million cubic feet of wellhead gas, 340 barrels of condensate, and over 500 barrels of natural gas liquids per day with flowing tubing pressures over 8500 psi on a 12/64-inch choke. Through the middle of March, the well had produced over 69,000 barrels of oil equivalent in its first 45 days of production, and is one of the stronger wells in the immediate area to-date. The JV recently elected to participate for its approximate 44% working interest in a nearby well, the Matejek Gas Unit 1-1, which is currently being drilled by Talisman USA. We anticipate that the JV will drill three or four additional wells in 2011.

Furthermore, with initial drilling success in our horizontal Strawn play in West Texas, the Portilla Field in South Texas, and the horizontal Pekisko play in Alberta, Canada behind us, we look forward to continuing these successes into 2011 with active multi-well drilling programs in each play. We also anticipate drilling our first horizontal Niobrara well in the Brooks Draw area of Wyoming this summer while we continue to monitor industry activity in the Alberta Basin Bakken play in northwestern Montana.

With our stock price more than double what it was last year at this time, it is satisfying to see the market recognize the value in Abraxas and our exciting plays. Our very successful equity offering early this year gives us the balance sheet and the liquidity to pursue our planned $60 million drilling program for 2011. I, our board and our employees, are happy to have you along for the ride.

Sincerely,

Robert L.G. Watson

ABRAXAS PETROLEUM CORPORATION
18803 Meisner Drive
San Antonio, Texas 78258
(210) 490-4788

April 1, 2011

Dear Stockholders:

You are invited to attend the 2011 Annual Meeting of Stockholders of Abraxas Petroleum Corporation to be held on Thursday, May 5, 2011, at 10:00 a.m., local time, at the Petroleum Club of San Antonio located at 8620 N. New Braunfels, Suite 700, San Antonio, Texas 78217. We hope that you will be able to attend the meeting. Matters on which action will be taken at the meeting are explained in detail in the notice and proxy statement following this letter.

Whether or not you expect to attend the annual meeting, it is important that you vote your shares. We are offering multiple options for voting your shares. All holders may vote their shares by mail or written ballot at the annual meeting. If you are a beneficial holder, you may also vote your shares by telephone or the Internet using the instructions on each proxy card. In order to vote your shares by mail, please mark, sign, and date the enclosed proxy and return it promptly in the enclosed envelope.

Thank you for your continued support of Abraxas Petroleum Corporation.

Robert L.G. Watson

Chairman of the Board, President,
and Chief Executive Officer

ABRAXAS PETROLEUM CORPORATION
18803 Meisner Drive
San Antonio, Texas 78258
(210) 490-4788

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

TO BE HELD MAY 5, 2011

To the Stockholders of Abraxas Petroleum Corporation:

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of Abraxas Petroleum Corporation ("Abraxas") will be held at the Petroleum Club of San Antonio located at 8620 N. New Braunfels, Suite 700, San Antonio, Texas 78217, on Thursday, May 5, 2011, at 10:00 a.m., local time, for the following purposes:

(1) To elect as directors to the Abraxas Board of Directors the three nominees named below for a term of three years:

- C. Scott Bartlett, Jr.
- Ralph F. Cox
- Dennis E. Logue

(2) To ratify the appointment of BDO USA, LLP as Abraxas' independent registered public accounting firm for the year ending December 31, 2011;

(3) To approve, by advisory vote, a resolution on executive compensation;

(4) To recommend, by advisory vote, the frequency of future advisory votes on executive compensation; and

(5) To transact any other business that has been properly brought before the meeting in accordance with the provisions of the Company's Amended and Restated Bylaws.

Our Board recommends that you vote FOR Proposals 1, 2 and 3 and for three (3) years for Proposal 4.

We invite you to attend the annual meeting in person. Whether or not you expect to attend the annual meeting, we urge you to mark, sign, date, and return the enclosed proxy card as soon as possible in the enclosed envelope. If you are a beneficial holder, you may also vote your shares by telephone or the Internet using the instructions on each proxy card. You may revoke your proxy at any time prior to the annual meeting, and, if you attend the annual meeting, you may vote your shares of Abraxas common stock in person.

The Board of Directors has fixed the close of business on March 28, 2011 as the record date for the determination of the stockholders entitled to notice of and to vote at the annual meeting and any adjournment thereof.

By Order of the Board of Directors

Stephen T. Wendel
SECRETARY

San Antonio, Texas
April 1, 2011

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of Stockholders to be held May 5, 2011

This proxy statement and our 2010 Annual Report on Form 10-K are available at www.abraxaspetroleum.com/proxy, which does not have "cookies" that identify visitors to the site.

ABRAXAS PETROLEUM CORPORATION

18803 Meisner Drive
San Antonio, Texas 78258
(210) 490-4788

PROXY STATEMENT

The Board of Directors of Abraxas Petroleum Corporation is soliciting proxies to vote shares of common stock at the 2011 Annual Meeting of Stockholders to be held at 10:00 a.m., local time, on Thursday, May 5, 2011, at the Petroleum Club of San Antonio, located at 8620 N. New Braunfels, Suite 700, San Antonio, Texas 78217, and at any adjournment thereof. This proxy statement and the accompanying proxy are first being mailed to stockholders on or about April 1, 2011. For ten days prior to the annual meeting, a complete list of stockholders entitled to vote at the annual meeting will be available for examination by any stockholder for any purpose relevant to the annual meeting during regular business hours at Abraxas' executive offices, located at the address set forth above.

Record Date; Shares Entitled To Vote; Quorum

The Board of Directors has fixed the close of business on March 28, 2011 as the record date for Abraxas stockholders entitled to notice of and to vote at the annual meeting. Only holders of common stock as of the record date are entitled to vote at the annual meeting. As of the record date, there were 91,670,093 shares of Abraxas common stock outstanding, which were held by approximately 1,197 holders of record. Stockholders are entitled to one vote for each share of Abraxas common stock held as of the record date.

The holders of a majority of the outstanding shares of Abraxas common stock issued and entitled to vote at the annual meeting must be present in person or by proxy to establish a quorum for business to be conducted at the annual meeting. Abstentions and "broker non-votes" are treated as shares that are present and entitled to vote for purposes of determining the presence of a quorum.

If you own shares through a bank or broker in street name, you may instruct your bank or broker how to vote your shares. A "broker non-vote" occurs when you fail to provide your bank or broker with voting instructions and the bank or broker does not have the discretionary authority to vote your shares on a particular proposal because the proposal is not a routine matter under New York Stock Exchange rules. Proposal 1 (election of directors) is not considered a routine matter under New York Stock Exchange rules, so your bank or broker will not have discretionary authority to vote your shares held in street name on that item. A broker non-vote may also occur if your broker fails to vote your shares for any reason. Proposal 2 (ratification of the appointment of our independent registered public accounting firm) is considered a routine matter under New York Stock Exchange rules, so your bank or broker will have discretionary authority to vote your shares held in street name on that item. Proposals 3 (say on pay) and 4 (frequency of say on pay) are advisory matters and your bank or broker does not have discretionary authority to vote your shares held in street name on those items.

Important Information Regarding Voting Instructions: Under the rules of the New York Stock Exchange, if you own shares in "street name" through a broker and do not vote, your broker may not vote your shares on proposals determined to be "non-routine." In such cases, the absence of voting instructions results in a "broker non-vote." Broker non-voted shares count toward achieving a quorum requirement for the annual meeting, but they do not affect the determination of whether the non-routine matter is approved or rejected. The proposal to ratify the appointment of BDO USA, LLP as our independent registered public accounting firm is the only matter in this proxy statement considered to be a routine matter for which brokers will be permitted to vote on behalf of their clients if no voting instructions are furnished. Since Proposals 1, 3 and 4 are non-routine matters, broker non-voted shares will not count as votes cast to affect the determination of whether they are approved or rejected. **Therefore, it is important that you provide voting instructions to your broker**.

Votes Required

The votes required for each proposal is as follows:

Election of Directors. The nominees for director who receive the most votes will be elected. Therefore, if you do not vote for a particular nominee or you indicate "withhold authority to vote" for a particular nominee on your proxy card, your abstention will have no effect on the election of directors. To be elected, each director must receive a majority of the votes cast (the number of shares voted "for" a director nominee must exceed the number of votes cast "against" that nominee) at the meeting. Non-votes are not considered votes cast "for" or "against" this proposal and will have no effect on the approval to elect directors.

Appointment of Independent Registered Public Accounting Firm. The proposal to ratify the appointment of Abraxas' independent registered public accounting firm must receive the affirmative vote of the holders of a majority of the total votes cast on the proposal. Therefore, abstentions will have the same legal effect as a vote against the proposal. Since this proposal is considered a "routine" matter, brokers will be permitted to vote on behalf of their clients, if no voting instructions are furnished.

Advisory Vote on Executive Compensation. The proposal to approve the compensation of Abraxas' executive officers is an advisory vote and must receive the affirmative vote of the holders of a majority of the total votes cast on the proposal. Non-votes are not considered votes cast "for" or "against" this proposal and will have no effect.

Frequency of Future Advisory Votes on Executive Compensation. The proposal to select the frequency of future advisory votes to approve the compensation of Abraxas' executive officers is an advisory vote and must receive the affirmative vote of the holders of a majority of the total votes cast on the proposal. Non-votes are not considered votes cast on this proposal and will have no effect.

Voting of Proxies

Votes cast in person or by proxy at the annual meeting will be tabulated at the annual meeting. All valid, unrevoked proxies will be voted as directed. In the absence of instructions to the contrary, properly executed proxies will be voted in favor of each of the proposals listed in the notice of annual meeting and for the election of the nominees for director set forth herein.

If any matters other than those addressed on the proxy card are properly presented for action at the annual meeting, the persons named in the proxy will have the discretion to vote on those matters in their best judgment, unless authorization is withheld.

Many of our stockholders hold their shares through a stockbroker, bank or other nominee rather than directly in their own names. As summarized below, there are some distinctions between shares held of record and those owned beneficially.

Stockholder of Record. If your shares are registered directly in your name or with our transfer agent, American Stock Transfer & Trust Company, you are considered the stockholder of record with respect to those shares and these proxy materials are being sent directly to you by us. As a stockholder of record, you have the right to grant your voting proxy directly to us or to vote in person at the annual meeting. We have enclosed a proxy card for your use.

Beneficial Holder. If your shares are held in a brokerage account or by a bank or other nominee, you are considered the beneficial owner of the shares held in street name, and these proxy materials are being forwarded to you by your broker, bank or other nominee who is considered the stockholder of record with respect to those shares. As the beneficial owner, you have the right to direct your broker on how to vote and are also invited to attend the meeting. However, since you are not the stockholder of record, you may not vote these shares in person at the meeting. Your broker, bank or other nominee has enclosed a proxy card for your use.

How To Vote By Proxy; Revocability of Proxies

To vote by proxy, you must mark, sign, date, and return the proxy card in the enclosed envelope. If you are a beneficial holder, you may also vote your shares by telephone or the Internet using the instructions on each proxy card. Any Abraxas stockholder who delivers a properly executed proxy may revoke the proxy at any time before it is voted. Proxies may be revoked by:

- delivering a written revocation of the proxy to the Abraxas Secretary before the annual meeting;
- submitting a later-dated proxy by mail, telephone or the Internet; or
- appearing at the annual meeting and voting in person.

Attendance at the annual meeting will not, in and of itself, constitute revocation of a proxy. An Abraxas stockholder whose shares are held in the name of its broker, bank or other nominee must bring a legal proxy from its broker, bank or other nominee to the meeting in order to vote in person.

Deadline for Voting by Proxy

In order to be counted, votes cast by proxy must be received prior to the annual meeting.

Solicitation of Proxies

Proxies will be solicited by mail. Proxies may also be solicited personally, or by telephone, fax, or other means by the directors, officers and employees of Abraxas. Directors, officers and employees soliciting proxies will receive no extra compensation, but may be reimbursed for related out-of-pocket expenses. In addition to solicitation by mail, Abraxas will make arrangements with brokerage houses and other custodians, nominees, and fiduciaries to send the proxy materials to beneficial owners. Abraxas will, upon request, reimburse these brokerage houses, custodians, and other persons for their reasonable out-of-pocket expenses in doing so. Abraxas will pay the cost of solicitation of proxies.

Important Information Regarding Delivery of Proxy Material

The Securities and Exchange Commission has adopted rules regarding how companies must provide proxy materials to their stockholders. These rules are often referred to as "notice and access," under which a company may select either of the following options for making proxy materials available to its stockholders:

- the full set delivery option; or
- the notice only option.

A company may use a single method for all of its stockholders, or use full set delivery for some while adopting the notice only option for others.

Full Set Delivery Option

Under the full set delivery option, a company delivers all proxy material to its stockholders by mail as it would have done prior to the change in the rules. In addition to delivery of proxy materials to stockholders, the company must post all proxy materials on a publicly-accessible website and provide information to stockholders about how to access the website.

In connection with its 2011 Annual Meeting of Stockholders, Abraxas has elected to use the full set delivery option. Accordingly, you should have received Abraxas' proxy materials by mail. These proxy materials include the Notice of Annual Meeting of Stockholders, proxy statement, proxy card and Annual Report on Form 10-K. Additionally, Abraxas has posted these materials at *www.abraxaspetroleum.com/proxy*.

Notice Only Option

Under the notice only option, a company must post all proxy materials on a publicly-accessible website. Instead of delivering proxy materials to its stockholders, the company instead delivers a "Notice of Internet Availability of Proxy Material." The notice includes, among other matters:

- information regarding the date and time of the annual meeting of stockholders as well as the items to be considered at the meeting;
- information regarding the website where the proxy materials are posted; and
- various means by which a stockholder can request paper or e-mail copies of the proxy materials.

If a stockholder requests paper copies of the proxy materials, these materials must be sent to the stockholder within three business days and by first class mail.

Abraxas May Use the Notice Only Option in the Future

Although Abraxas elected to use the full set delivery option in connection with the 2011 Annual Meeting of Stockholders, it may choose to use the notice only option in the future. By reducing the amount of materials that a company needs to print and mail, the notice only option provides an opportunity for costs savings as well as conservation of paper products. Many companies that have used the notice only option have also experienced a lower participation rate resulting in fewer stockholders voting at the annual meeting. Abraxas plans to evaluate the future possible cost savings as well as the possible impact on stockholder participation as it considers future use of the notice only option.

Householding

The Securities and Exchange Commission has adopted rules that permit companies and intermediaries (e.g. brokers) to satisfy the delivery requirements for proxy materials with respect to two or more stockholders sharing the same address by delivering a single set of proxy materials. This process, which is commonly referred to as "householding," potentially results in extra convenience for stockholders, cost savings for companies and conservation of paper products.

If, at any time, you no longer wish to participate in "householding" and would prefer to receive a separate set of proxy materials, you may:

- Send a written request to Investor Relations, Abraxas Petroleum Corporation, 18803 Meisner Drive, San Antonio, Texas 78258, if you are a stockholder of record; or
- Notify your broker, if you hold your shares in street name.

PROPOSAL ONE

Election of Directors

Abraxas' Articles of Incorporation divide the Board of Directors into three classes of directors serving staggered three-year terms, with one class to be elected at each annual meeting. At this year's meeting, three Class II directors are to be elected for a term of three years to hold office until the expiration of their term in 2014, or until a successor has been elected and duly qualified. The nominees for Class II directors are C. Scott Bartlett, Jr., Ralph F. Cox and Dennis E. Logue.

Assuming the presence of a quorum, the nominees for director who receive the most votes will be elected. The enclosed proxy card provides a means for stockholders to vote for or to withhold authority to vote for the nominees for director. If a stockholder executes and returns a proxy, but does not specify how the shares represented by such stockholder's proxy are to be voted, such shares will be voted FOR the election of the nominees for director. In determining whether this item has received the required number of affirmative votes, abstentions will have no effect. Non-votes are not considered votes cast "for" or "against" this proposal at the annual meeting and will have no effect on the approval to elect directors.

The Board of Directors recommends a vote "FOR" the election of the nominees to the Board of Directors.

Board of Directors and Executive Officers

The following table sets forth the names, ages, and positions of the executive officers and directors of Abraxas. The term of the Class I directors expires in 2012, the term of the Class II directors expires in 2011 and the term of the Class III directors expires in 2013.

Name and Municipality of Residence	Age	Office	Class
Robert L.G. Watson San Antonio, Texas	60	Chairman of the Board, President and Chief Executive Officer	III
C. Scott Bartlett, Jr. Richmond Hill, Georgia	77	Director	II
Franklin A. Burke(1) Doyleston, Pennsylvania	77	Director	I
Harold D. Carter Dallas, Texas	72	Director	III
Ralph F. Cox Fort Worth, Texas	78	Director	II
Dennis E. Logue Enfield, New Hampshire	67	Director	II
Brian L. Melton Overland Park, Missouri	41	Director	III
Paul A. Powell, Jr. Roanoke, Virginia	65	Director	I
Edward P. Russell Stilwell, Kansas	47	Director	III
Chris E. Williford San Antonio, Texas	59	Executive Vice President, Chief Financial Officer and Treasurer	—
Lee T. Billingsley San Antonio, Texas	58	Vice President – Exploration	—
William H. Wallace Blanco, Texas	53	Vice President – Operations	—
Stephen T. Wendel San Antonio, Texas	61	Vice President – Land & Marketing and Corporate Secretary	—
Barbara M. Stuckey San Antonio, Texas	42	Vice President – Corporate Finance and Assistant Secretary	—

(1) Mr. Burke will be retiring from the Abraxas Board of Directors at the end of his term in 2012. At that time, Mr. Burke will be appointed a director emeritus of Abraxas.

Executive Officers

Robert L.G. Watson has served as Chairman of the Board, President, Chief Executive Officer and a director of Abraxas since 1977. Mr. Watson currently serves on the board of managers of Blue Eagle Energy, LLC, a joint venture between Abraxas and Rock Oil Company, LLC, to develop the Eagle Ford Shale play in South Texas. From January 2003 to July 2009, Mr. Watson served as Chairman of the Board, Chief Executive Officer and director of Grey Wolf Exploration Inc., which we refer to as Grey Wolf, an oil and gas exploration and production company and which was, until February 2005, a wholly-owned subsidiary of Abraxas. From May 1996 to January 2003, Mr. Watson served as President, Chairman of the Board and a director of Grey Wolf Exploration, Inc., a former wholly-owned subsidiary of Abraxas, which we refer to as Old Grey Wolf, the capital stock of which was sold by Abraxas in January 2003. From November 1996 to January 2003, Mr. Watson was Chairman of the Board, President and a director of Canadian Abraxas Petroleum Limited, which we refer to as Canadian Abraxas, a former wholly-owned Canadian subsidiary of Abraxas, the capital stock of which was sold by Abraxas in January 2003. Prior to forming Abraxas, Mr. Watson held petroleum engineering positions with Tesoro Petroleum Corporation and DeGolyer and MacNaughton. Mr. Watson received a Bachelor of Science degree in Mechanical Engineering from Southern Methodist University in 1972 and a Master of Business Administration degree from the University of Texas at San Antonio in 1974.

Chris E. Williford was elected Vice President, Treasurer and Chief Financial Officer of Abraxas in January 1993 and as Executive Vice President and a director of Abraxas in May 1993. Mr. Williford resigned as a director of Abraxas in December 1999. From November 1996 to January 2003, Mr. Williford was Vice President and Assistant Secretary of Canadian Abraxas and Vice President of Old Grey Wolf. Prior to joining Abraxas, Mr. Williford was Chief Financial Officer of American Natural Energy Corporation and President of Clark Resources Corp. Mr. Williford received a Bachelor of Science degree in Business Administration from Pittsburg State University in 1973.

Lee T. Billingsley has served as Vice President – Exploration since 1998. Dr. Billingsley founded Sandia Oil & Gas Corp. in 1983 and served as its President until Sandia merged into Abraxas in 1998. Prior to forming Sandia, Dr. Billingsley worked for Tenneco Oil Company and American Quasar Petroleum. Dr. Billingsley served as President of the American Association of Petroleum Geologists (AAPG) for the 2006-2007 term. Dr. Billingsley holds three degrees in Geology, Bachelor of Science and Doctorate from Texas A&M University and Master of Science from Colorado School of Mines.

William H. Wallace has served as Vice President—Operations since 2000. Mr. Wallace served as Abraxas' Superintendent/Senior Operations Engineer, from 1995 to 2000. Prior to joining Abraxas, Mr. Wallace worked for Dorchester Gas Producing Company and Parker and Parsley. Mr. Wallace received a Bachelor of Science degree in Petroleum Engineering from Texas Tech University in 1981.

Stephen T. Wendel has served as Vice President—Land and Marketing since 1990 and as Corporate Secretary since 1988. Mr. Wendel served as Abraxas' Manager of Joint Interests and Natural Gas Contracts, from 1982 to 1990. Prior to joining Abraxas, Mr. Wendel held accounting, auditing and marketing positions with Tenneco Oil Company and Tesoro Petroleum Corporation. Mr. Wendel also serves as a director of the Corporation Board and the Development Board of Texas Lutheran University. Mr. Wendel received a Bachelor of Business Administration degree in Accounting from Texas Lutheran University in 1971.

Barbara M. Stuckey has served as Vice President – Corporate Finance and Assistant Secretary since 2007. Ms. Stuckey joined Abraxas in 1997 and has held positions in investor relations, corporate finance, land and marketing. Prior to joining Abraxas, Ms. Stuckey was a paralegal and a flight instructor. Ms. Stuckey received a Bachelor of Arts degree from the University of Texas at San Antonio in 1991 and a Master of Business Administration degree from the Bordeaux Business School in 2004.

Director Nominees

C. Scott Bartlett, Jr., a director of Abraxas since December 1999, has over 50 years of commercial banking experience, the most recent being with National Westminster Bank USA (prior to being acquired by Bank of America), ultimately serving as Executive Vice President, Senior Lending Officer and Chairman of the Credit Policy Committee. Mr. Bartlett previously served as a director of NVR, Inc., a publicly-traded, nationwide home builder, from 1993 to 2009, and where he also served on the audit committee for 15 years. Mr. Bartlett attended Princeton University, and has a certificate in Advanced Management from Pennsylvania State University.

Ralph F. Cox, a director of Abraxas since December 1999, has over 50 years of oil and gas industry experience, over 30 of which was with Atlantic Richfield Company (ARCO). Mr. Cox retired from ARCO in 1985 after serving as Vice Chairman. Mr. Cox then joined Union Pacific Resources, retiring in 1989 as President and Chief Operating Officer. Mr. Cox then joined Greenhill Petroleum Corporation as President until leaving in 1994 to pursue a consulting business. Mr. Cox currently serves on the board of CH2M Hill Companies, an engineering and construction firm, and as a trustee for Fidelity Mutual Funds. Mr. Cox also serves as a director of Validus International, a company specializing in oil field drilling tools, and as a director of E-T Energy Ltd., a Canadian oil sands extraction company. Mr. Cox previously served as a director of Abraxas General Partner, LLC, the general partner of Abraxas Energy Partners, L.P., as a director of World GTL Inc., a gas-to-liquids production facility, and as an advisory director of Impact Petroleum, an oil and gas exploration and production company. Mr. Cox received Bachelor of Science degrees in Petroleum Engineering and Mechanical Engineering from Texas A&M University in 1954 and completed advanced studies at Emory University.

Dennis E. Logue, a director of Abraxas since April 2003, has served as Chairman of the Board of Directors of Ledyard Financial Group, the holding company for Ledyard National Bank, since August 2005. Mr. Logue served as Dean and Fred E. Brown Chair at the Michael F. Price College of Business at the University of Oklahoma from 2001 through September 2005. Prior to joining Price College, Mr. Logue was the Steven Roth Professor at the Amos Tuck School at Dartmouth College where he had been since 1974. Mr. Logue has served as a director of Waddell & Reed Financial, Inc., a publicly-traded, national financial services organization, since 2002 and Duckwall-ALCO Stores, Inc., a publicly-traded, general merchandise retailer serving smaller, hometown communities, since 2005. Mr. Logue also serves on the board of Hypertherm, a privately-owned company specializing in plasma cutting tools and technology, and as a Trustee for the Montshire Museum of Science and Crossroads Academy. Mr. Logue holds degrees from Fordham College, Rutgers, and Cornell University.

Directors with Terms Expiring in 2012 and 2013

Franklin A. Burke, a director of Abraxas since June 1992, has served as President and Chief Executive Officer of Burke, Lawton, Brewer & Burke, a securities brokerage firm, since 1964, as President of Venture Securities Corporation, since 1971, and as President, Director of Research and Portfolio Management of BLB&B Advisors, LLC, since 2006. Mr. Burke also serves as Trustee and Treasurer of The Williamson Free School of Mechanical Trades. Mr. Burke currently serves as a director of Starkey Chemical Process Company and as a director and President of Omega Institute, an allied health post-secondary school. Mr. Burke received a Bachelor of Science degree in Business Administration from Kansas State University in 1955, a Masters degree in Finance from University of Colorado in 1960 and studied at the graduate level at the London School of Economics from 1962 to 1963.

Harold D. Carter, a director of Abraxas since October 2003, has over 40 years of oil and gas industry experience and has been an independent consultant since 1990. Prior to consulting, Mr. Carter served as Executive Vice President of Pacific Enterprises Oil Company (USA). Before that, Mr. Carter was associated for 20 years with Sabine Corporation, ultimately serving as President and Chief Operating Officer from 1986 to 1989. Mr. Carter has served as a director of Brigham Exploration Company, a publicly-traded oil and gas company, since 1998 and Longview Energy Company, a privately-owned oil and gas exploration and production company, since 1999. Mr. Carter also serves as Vice Chairman of the Board of Trustees for the Texas Scottish Rite Hospital for Children. Mr. Carter previously served as a director of Abraxas from 1996 to 1999 and as an advisory director from 1999 to October 2003, and as a director of Energy Partners. Ltd, a publicly-traded oil and gas exploration and production company, from 2000 to 2009. Mr. Carter received a Bachelor of Business Administration degree in Petroleum Land Management from the University of Texas and completed the Program for Management Development at the Harvard University Business School.

Brian L. Melton, a director of Abraxas since October 2009, has served as Vice President of Corporate Strategy of Inergy, L.P. (NYSE:NRGY), a publicly-traded master limited partnership that specializes in retail propane distribution and midstream natural gas and natural gas liquids storage facilities, since September 2008. Prior to joining Inergy, Mr. Melton was a Director in the Energy Corporate Investment Banking groups of Wachovia Securities and A.G. Edwards, prior to its merger with Wachovia in October of 2007. Mr. Melton joined A.G. Edwards in July 2000 and was a senior member of the energy corporate finance team. From November 1995 until July 2000, Mr. Melton served as Director of Finance & Corporate Planning with TransMontaigne Inc., a downstream refined products supply, transportation and logistics company. Mr. Melton previously served as a director of Abraxas General Partner, LLC, the general partner of Abraxas Energy Partners, L.P. Mr. Melton received a Bachelor of Science degree in Management and a Master of Business Administration degree from Arkansas State University.

Paul A. Powell, Jr., a director of Abraxas since August 2005, has served as Vice President and director of Mechanical Development Co., Inc. a maker of precision production machine parts, since 1984. Mr. Powell is a managing partner of Claytor Equity Partners, Cortland Partners, JWM Partners, Emory Partners and Burnett Partners. Mr. Powell is also manager of Westpoint (2002) LLC, Westpoint (2002) General Limited Partnership and WMP Properties LLC, and co-manager of Emisshield, LLC. Mr. Powell currently serves on the board of trustees of Emory & Henry College and as trustee for numerous charitable trusts. Mr. Powell previously served as a director of Abraxas from 1987 to 1999 and as an advisory director from 1999 to August 2005, in addition to previously serving on the board of the Blue Ridge Mountain Council and Boy Scouts of America. Mr. Powell attended Emory & Henry College and graduated from National Business College with a degree in Accounting.

Edward P. Russell, a director of Abraxas since October 2009, has served as President of Tortoise Capital Resources Corp. since April 2007. Prior to joining Tortoise Capital Advisors, Mr. Russell was a Managing Director at Stifel, Nicolaus & Company, Inc. where he headed the Energy and Power group. Prior to Stifel, Mr. Russell served more than 15 years as an investment banker at Pauli & Company, Inc. and Arch Capital, LLC. Mr. Russell also serves as a director of VantaCore Partners, a private partnership specializing in aggregates. Mr. Russell previously served as a director of Abraxas General Partner, LLC, the general partner of Abraxas Energy Partners, L.P., and Quest Midstream Partners, L.P., a privately-owned partnership.

Robert L.G. Watson**,** Abraxas' Chairman of the Board, President and Chief Executive Officer, is a Class III director with a term expiring in 2013.

Composition of the Board of Directors

The Company believes that its Board as a whole should encompass a range of talent, skill, diversity, experience and expertise enabling it to provide sound guidance with respect to the Company's operations and business goals. In addition to considering a candidate's background and accomplishments, candidates are reviewed in the context of the current composition of the Board and the evolving needs of the Company. The Company's policy is to have at least a majority of its directors qualify as "independent" as determined in accordance with the listing standards of The NASDAQ Stock Market and Rule 10A-3 of the Exchange Act. The Nominating and Corporate Governance Committee identifies candidates for election to the Board of Directors and reviews their skills, characteristics and experience, and recommends nominees for director to the Board for approval.

The Nominating and Corporate Governance Committee seeks directors with strong reputations and experience in areas relevant to the strategy and operations of the Company, particularly in the oil and gas industry and complex business and financial dealings. Each of the nominees for election as a director at the annual meeting and each of the Company's current directors holds or has held senior executive positions in either the oil and gas industry or in the financial / banking community. In these positions, we believe that each nominee and current director has gained experience in core management skills, such as strategic and financial planning, public company financial reporting, corporate governance, risk management, and leadership development. Many of our directors also have experience serving on boards and board committees of other public companies, as well as charitable organizations and private companies. The Nominating and Corporate Governance Committee also believes that each nominee and current director has other key attributes that are important to an effective board: integrity and demonstrated high ethical standards; sound judgment; analytical skills; the ability to engage management and each other in a constructive and collaborative fashion; diversity of background, experience and thought; and the commitment to devote significant time and energy to service on the Board and its Committees. With respect to each of our current directors and director nominees, their biographies beginning on page 6 detail their individual experience in the oil and gas industry and/or in the financial / banking community together with their past and current board positions. Messrs. Carter and Cox have strong backgrounds in the oil and gas industry and Messrs. Bartlett, Burke, Logue and Powell have strong backgrounds in the financial / banking community. Messrs. Melton and Russell have strong backgrounds in both the oil and gas industry and the financial / banking community.

Meeting Attendance

During the fiscal year ended December 31, 2010, the Board of Directors held four meetings, the Audit Committee held four meetings and the Compensation Committee held one meeting. The Nominating and Corporate Governance Committee did not meet in 2010; however, it did meet in March 2011. During 2010, each director attended at least 75% of all Board and applicable Committee meetings. During 2010, Abraxas' directors, other than Mr. Watson, received compensation for service to Abraxas as a director. See "Executive Compensation—Compensation of Directors." The directors also received reimbursement of travel expenses to attend board and committee meetings. Abraxas encourages, but does not require, directors to attend the annual meeting of stockholders. Such attendance allows for direct interaction between stockholders and members of the Board of Directors. At Abraxas' 2010 Annual Meeting, all members of the Board were present.

Committees of the Board of Directors

Abraxas has standing Audit, Compensation and Nominating and Corporate Governance Committees.

The Audit Committee is a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Audit Committee consists of Messrs. Bartlett (Chairman), Burke, Melton and Powell. The Board of Directors has determined that C. Scott Bartlett, Jr., as defined by SEC rules, is an audit committee financial expert. The Audit Committee Report, which begins on page 37, more fully describes the activities and responsibilities of the Audit Committee. At each meeting, which is attended by Mr. Williford, BDO USA, LLP and the Audit Committee meet in executive session.

The Compensation Committee consists of Messrs. Cox (Chairman), Carter and Logue. The Compensation Committee's role is to establish and oversee Abraxas' compensation and benefit plans and policies, administer its stock option plans, and to annually review and approve all compensation decisions relating to Abraxas' executive officers. The Compensation Discussion & Analysis, which begins on page 16, more fully describes the activities and responsibilities of the Compensation Committee. The Compensation Committee submits its decisions regarding executive compensation to the independent members of the Board for approval. The agenda for meetings of the Compensation Committee is determined by its Chairman and the meetings are regularly attended by Mr. Watson. At each meeting, the Compensation Committee also meets in executive session. Mr. Cox reports the committee's recommendations on executive compensation to the Board. The Company's personnel support the Compensation Committee in its duties and, along with Mr. Watson, may be delegated authority to fulfill certain administrative duties regarding the Company's compensation programs. The Compensation Committee has authority under its charter to retain, approve fees for and terminate advisors, consultants and agents as it deems necessary to assist in the fulfillment of its responsibilities but has not, in the past, utilized the services of a third party consultant to review the policies and procedures with respect to executive compensation. The Compensation Committee may engage a third party to provide such services in the future, as it deems necessary or appropriate at the time in question. For more information on the Compensation Committee's processes and procedures, please see "Executive Compensation—Compensation Discussion and Analysis—Our Compensation Committee" and—"Elements of Executive Compensation."

The Nominating and Corporate Governance Committee consists of Messrs. Cox, Logue (Chairman) and Powell. The primary function of the Nominating and Corporate Governance Committee is to develop and maintain the corporate governance policies of Abraxas and to assist the Board in identifying, screening and recruiting qualified individuals to become Board members and determining the composition of the Board and its committees, including recommending nominees for the election at the annual meeting of stockholders or to fill vacancies on the Board.

Each of the Board's committees has a written charter, and copies of the charters are available for review on the Company's website at *www.abraxaspetroleum.com*.

Director Independence

The Board of Directors has determined that each of the following members of the Board of Directors is independent as determined in accordance with the listing standards of The NASDAQ Stock Market and Rule 10A-3 of the Exchange Act: C. Scott Bartlett, Jr., Franklin A. Burke, Harold D. Carter, Ralph F. Cox, Brian L. Melton, Dennis E. Logue, Paul A. Powell, Jr. and Edward P. Russell. All of the members of the Audit, Compensation and Nominating and Corporate Governance Committees are independent as determined in accordance with the listing standards of The NASDAQ Stock Market and Rule 10A-3 of the Exchange Act. The Board of Directors periodically conducts a self-evaluation on key Board and committee-related issues, which has proven to be a beneficial tool in the process of continuous improvement in Board functioning and communication.

Board Leadership Structure

The Board of Directors believes that the Chief Executive Officer is best situated to serve as Chairman because he is the director most familiar with Abraxas' business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. The Board believes this provides an efficient and effective leadership model for Abraxas. The Board believes that combining the Chairman and Chief Executive Officer roles fosters clear accountability, effective decision-making and alignment on corporate strategy. To assure effective independent oversight, the Board has adopted a number of governance practices, including:

- A strong, independent director role;
- Regular executive sessions of the independent directors; and
- Annual performance evaluations of the Chairman and Chief Executive Officer by the independent directors.

In addition, in 2006, the Board appointed Mr. Cox as lead independent director to provide the Board with additional independent oversight. Mr. Cox leads the regularly held executive sessions. The Board believes that the combined role of Chairman and Chief Executive Officer is in the best interest of Abraxas stockholders because it provides the appropriate balance between strategic development and independent oversight of management.

Risk Management

The Board of Directors has an active role, as a whole and also at the committee level, in overseeing management of the Company's risks. The Board reviews quarterly information regarding the Company's credit, liquidity and operations, as well as the risks associated with each. The Company's Compensation Committee is responsible for overseeing the management of risks relating to the Company's executive compensation plans and arrangements to ensure that the compensation programs do not encourage excessive risk-taking. The Audit Committee oversees management of financial risks. The Nominating and Corporate Governance Committee manages the risks associated with the independence of the Board of Directors and potential conflicts of interest. While each committee is responsible for evaluating specific risks and overseeing the management of such risks, the entire Board of Directors is regularly informed through committee reports about such risks.

The Board of Directors, together with the Compensation Committee, the Audit Committee, and the Nominating and Corporate Governance Committee, coordinate with each other to provide company-wide oversight of our management and handling of risk. These committees report regularly to the entire Board of Directors on risk-related matters and provide the Board of Directors with integrated insight about the Company's management of strategic, credit, interest rate, financial reporting, liquidity, compliance and operational risks. While the Company has not developed a company-wide risk statement, the Board of Directors believes a well-balanced operational risk profile with heavier weighting towards exploitation projects as opposed to exploratory projects together with a relatively conservative approach to managing liquidity, debt levels, and commodity price and interest rate risk contribute to an effective oversight of the Company's risks.

At meetings of the Board of Directors and its committees, directors receive regular updates from management regarding risk management. Outside of formal meetings, the Board, its committees and individual Board members have regular access to the executive officers of Abraxas.

Compensation Committee Interlocks and Insider Participation

Messrs. Cox, Carter and Logue served on the Compensation Committee during 2010. No member of the Compensation Committee was at any time during 2010 or at any other time an officer or employee of Abraxas, and no member had any relationship with Abraxas requiring disclosure as a related-party transaction in the section "Certain Relationships and Related Transactions" of this proxy statement. Messrs. Cox, Melton and Russell were also directors of Abraxas General Partner, LLC, the general partner of Abraxas Energy Partners, L.P., prior to its merger with and into a wholly-owned subsidiary of Abraxas in October 2009. No executive officer of Abraxas has served on the board of directors or compensation committee of any other entity that has or has had one or more executive officers who served as a member of the Board of Directors or the Compensation Committee during 2010.

Code of Ethics

In April 2004, the Board of Directors unanimously approved Abraxas' Code of Ethics. This Code is a statement of Abraxas' high standards for ethical behavior, legal compliance and financial disclosure, and is applicable to all directors, officers, and employees. A copy of the Code of Ethics can be found in its entirety on Abraxas' website at *www.abraxaspetroleum.com*. Additionally, should there be any changes to, or waivers from, Abraxas' Code of Ethics, those changes or waivers will be posted immediately on our website at the address noted above.

Stockholder Communications with the Board

The Board of Directors has implemented a process by which stockholders may communicate with the Board of Directors. Any stockholder desiring to communicate with the Board of Directors may do so in writing by sending a letter addressed to the Board of Directors, c/o Corporate Secretary. The Corporate Secretary has been instructed by the Board to promptly forward any communications received to the members of the Board.

Nominations

The Nominating and Corporate Governance Committee is responsible for determining the slate of director nominees for election by stockholders, which the committee recommends for consideration by the Board. All director nominees are approved by the Board prior to annual proxy material preparation and are required to stand for election by stockholders at the next annual meeting. For positions on the Board created by a director's leaving the Board prior to the expiration of his current term, whether due to death, resignation, or other inability to serve, Article III of the Company's Amended and Restated Bylaws provides that a director elected by the Board to fill a vacancy shall be elected for the unexpired term of his predecessor in office.

The Nominating and Corporate Governance Committee does not currently utilize the services of any third party search firm to assist in the identification or evaluation of Board member candidates. The Nominating and Corporate Governance Committee may engage a third party to provide such services in the future, as it deems necessary or appropriate at the time in question.

The Nominating and Corporate Governance Committee determines the required selection criteria and qualifications of director nominees based upon the needs of the Company at the time nominees are considered. A candidate must possess the ability to apply good business judgment and must be in a position to properly exercise his duties of loyalty and care. Candidates should also exhibit proven leadership capabilities, high integrity and experience with a high level of responsibility within their chosen fields, and have the ability to quickly understand complex principles of, but not limited to, business and finance. Candidates with potential conflicts of interest or who do not meet independence criteria will be identified and disqualified. The Nominating and Corporate Governance Committee will consider these criteria for nominees identified by the Committee, by stockholders, or through some other source. When current Board members are considered for nomination for re-election, the Nominating and Corporate Governance Committee also takes into consideration their prior Board contributions, performance and meeting attendance records.

The Nominating and Corporate Governance Committee does not have a formal policy with regard to the consideration of diversity in identifying director nominees, but the Committee strives to nominate directors with a variety of complementary skills so that, as a group, the Board will possess the appropriate talent, skills, experience and expertise to oversee the Company's business. As part of this process, the Committee evaluates how a particular candidate would strengthen and increase the diversity of the Board in terms of how that candidate may contribute to the Board's overall balance of perspectives, backgrounds, knowledge, experience, skill sets and expertise in substantive matters pertaining to the Company's business.

The Nominating and Corporate Governance Committee will consider qualified candidates for possible nomination that are recommended by stockholders. Stockholders wishing to make such a recommendation may do so by sending the required information to the Nominating and Corporate Governance Committee, c/o Corporate Secretary at the address listed above. Any such nomination must comply with the advance notice provisions and provide all of the information required by Abraxas' Amended and Restated Bylaws. These provisions and required information are summarized under "Stockholder Proposals for 2012 Abraxas Annual Meeting" beginning on page 41 of this proxy statement.

The Nominating and Corporate Governance Committee conducts a process of making a preliminary assessment of each proposed nominee based upon the resume and biographical information, an indication of the individual's willingness to serve and other background information. This information is evaluated against the criteria set forth above as well as the specific needs of the Company at that time. Based upon a preliminary assessment of the candidate(s), those who appear best suited to meet the needs of the Company may be invited to participate in a series of interviews, which are used for further evaluation. The Nominating and Corporate Governance Committee uses the same process for evaluating all nominees, regardless of the original source of the information.

No candidates for director nominations were submitted to the Nominating and Corporate Governance Committee by any stockholder in connection with the 2011 Annual Meeting.

SECURITIES HOLDINGS OF PRINCIPAL STOCKHOLDERS, DIRECTORS, NOMINEES AND OFFICERS

Based upon information received from the persons concerned, each person known to Abraxas to be the beneficial owner of more than five percent of the outstanding shares of common stock of Abraxas, each director and nominee for director, each of the executive officers and all directors and officers of Abraxas as a group, owned beneficially as of March 15, 2011, the number and percentage of outstanding shares of common stock of Abraxas indicated in the following table. Abraxas' Board has adopted stock ownership guidelines. Please read "Executive Compensation—Stock Ownership Guidelines." None of the shares listed below have been pledged as security.

Name of Beneficial Owner	Number of Shares(1)	Percentage (%)
Robert L.G. Watson	1,646,310(2)	1.8%
Chris E. Williford	435,191(3)	*
Lee T. Billingsley	378,512(4)	*
William H. Wallace	287,405(5)	*
Stephen T. Wendel	390,147(6)	*
Barbara M. Stuckey	266,470(7)	*
C. Scott Bartlett, Jr.	151,923(8)	*
Franklin A. Burke	4,625,638(9)	5.0%
Harold D. Carter	223,124(10)	*
Ralph F. Cox	456,949(11)	*
Dennis E. Logue	179,949(12)	*
Brian L. Melton	49,014(13)	*
Paul A. Powell, Jr.	214,328(14)	*
Edward P. Russell	32,014(15)	*
Lehman Brothers MLP Opportunity Fund	5,451,426 (16)	6.0%
Third Point LLC	4,801,054(17)	5.2%
All Officers and Directors as a Group (14 persons)	9,336,974 (2)(3)(4)(5)(6)(7)(8)(9)(10)(11)(12)(13)(14)(15)	10.2%

* Less than 1%

(1) Unless otherwise indicated, all shares are held directly with sole voting and investment power.

(2) Includes 163,713 shares issuable upon exercise of options granted pursuant to the Abraxas Petroleum Corporation 1994 Long Term Incentive Plan (the "1994 LTIP"), 283,156 shares issuable upon exercise of options granted pursuant to the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (the "2005 Employee Plan") and 32,810 shares in a retirement account. Does not include a total of 75,880 shares owned by the Robert L.G. Watson, Jr. Trust and the Carey B. Watson Trust, the trustees of which are Mr. Watson's brothers and the beneficiaries of which are Mr. Watson's children. Mr. Watson disclaims beneficial ownership of the shares owned by these trusts.

(3) Includes 63,000 shares issuable upon exercise of options granted pursuant to the 1994 LTIP, 168,160 shares issuable upon exercise of options granted pursuant to the 2005 Employee Plan and 20,522 shares in a retirement account.

(4) Includes 37,000 shares issuable upon exercise of options granted pursuant to the 1994 LTIP, 119,143 shares issuable upon exercise of options granted pursuant to the 2005 Employee Plan and 28,213 shares in a retirement account.

(5) Includes 52,000 shares issuable upon exercise of options granted pursuant to the 1994 LTIP, 120,925 shares issuable upon exercise of options granted pursuant to the 2005 Employee Plan and 7,680 shares in a retirement account.

(6) Includes 17,000 shares issuable upon exercise of options granted pursuant to the 1994 LTIP, 118,233 shares issuable upon exercise of options granted pursuant to the 2005 Employee Plan and 95,112 shares in a retirement account.

(7) Includes 122,266 shares issuable upon exercise of options granted pursuant to the 2005 Employee Plan and 18,578 shares in a retirement account.

(8) Includes 62,500 shares issuable upon exercise of options granted pursuant to the Abraxas Petroleum Corporation 2005 Non-Employee Director Long-Term Equity Incentive Plan (the "2005 Directors Plan") and 26,000 shares in a retirement account.

(9) Includes 45,000 shares issuable upon exercise of certain option agreements, 85,000 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan, 191,330 shares in a retirement account, 2,488,195 shares owned by Venture Securities Corporation Profit Sharing Trust Plan (voluntary), Venture Securities Corporation Profit Sharing Plan Trust (designated) and Venture Securities Corporation Pension Plan Trust over which Mr. Burke has shared discretion to dispose of, direct the disposition of, vote, and direct the voting of such shares for the benefit of the beneficiary of the trust, 16,500 shares in various trust and guardianship accounts, of which Mr. Burke is a trustee or guardian, 24,222 shares in the Pleasantville Church Foundation, of which Mr. Burke is a director, and 1,399,592 shares managed by BLB&B Advisors, LLC, of which Mr. Burke is the sole owner, on behalf of third parties. Mr. Burke does not have any voting rights with regard to the shares managed by BLB&B Advisors, LLC.

(10) Includes 45,000 shares issuable upon exercise of certain option agreements, 85,000 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan, 7,577 shares in a family trust and 40,598 shares in a retirement account.

(11) Includes 85,000 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan.

(12) Includes 58,000 shares issuable upon exercise of certain option agreements and 85,000 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan.

(13) Includes 28,750 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan.

(14) Includes 45,000 shares issuable upon exercise of certain option agreements, 85,000 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan and 27,277 shares in various entities managed by Mr. Powell.

(15) Includes 28,750 shares issuable upon exercise of options granted pursuant to the 2005 Directors Plan.

(16) The Board of Directors of Lehman Brothers Holding Inc., whose members may change from time to time, has voting and investment control over the shares held by Lehman Brothers MLP Opportunity Fund L.P. The members of the Board of Directors of Lehman Brothers Holdings Inc. disclaim beneficial ownership of all of such units. The address of Lehman Brothers MLP Opportunity Fund L.P. is 1271 Avenue of the Americas, 38th Floor, New York, NY 10020. Lehman Brothers MLP Opportunity Fund L.P.'s general partner is an indirect wholly-owned subsidiary of Lehman Brothers Holdings Inc.

(17) Third Point LLC, and Daniel S. Loeb, in his capacity as the CEO of Third Point LLC, have voting and investment control over the shares held by Third Point Partners LP and Third Point Partners Qualified LP. Third Point LLC is the investment advisor for Third Point Partners LP and Third Point Partners Qualified LP. The address of Third Point LLC is 390 Park Avenue, 18th Floor, New York, NY 10022.

Equity Compensation Plan Information

The following table gives aggregate information regarding grants under all of Abraxas' equity compensation plans through December 31, 2010.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	4,627,450	\$2.25	1,623,002
Equity compensation plans not approved by security holders	193,000	\$1.67	—

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires Abraxas' directors and executive officers and persons who own more than 10% of a registered class of Abraxas equity securities to file with the Securities and Exchange Commission and The NASDAQ Stock Market 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 regulation 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, Abraxas believes that during 2010, all of its directors and executive officers complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act.

EXECUTIVE COMPENSATION

Compensation Discussion & Analysis

We compensate our executive officers through a combination of base salary, annual incentive bonuses and long-term equity based awards. The compensation is designed to be competitive with those of a peer group which we have selected for comparative purposes and to align the interests of our executive officers with the interests of our stockholders.

This section discusses the principles underlying our executive compensation policies and decisions, and the most important factors relevant to an analysis of these policies and decisions. It provides qualitative information regarding the manner and context in which compensation is awarded to and earned by our executive officers and places in perspective the data presented in the tables and narrative that follow.

Our Compensation Committee

Our Compensation Committee approves, implements and monitors all compensation and awards to executive officers including the chief executive officer, chief financial officer and the other executive officers named in the Summary Compensation Table below, to whom we refer to as the named executive officers. The Committee's membership is determined by the Board of Directors and is composed of three independent directors. The Committee, in its sole discretion, has the authority to delegate any of its responsibilities to subcommittees as it deems appropriate. The Committee did not delegate any of its responsibilities during 2010.

The Committee periodically approves and adopts, or makes recommendations to the Board, for Abraxas' executive compensation decisions. In the first quarter of each year, Mr. Watson, the Chief Executive Officer, submits to the Compensation Committee his recommendations for salary adjustments and long-term equity incentive awards based upon his subjective evaluation of individual performance and his subjective judgment regarding each executive officer's salary and equity incentives, for each executive officer except himself. For more information on our Compensation Committee, please refer to the discussion under "Proposal One—Election of Directors—Committees of the Board of Directors."

The Committee reviews all components of compensation for our executive officers, including base salary, annual incentive bonuses, long-term equity based awards, the dollar value to the executive and cost to Abraxas of all benefits and all severance and change in control arrangements. Based on this review, the Compensation Committee has determined that the compensation paid to our executive officers reflects our compensation philosophy and objectives.

Compensation Philosophy and Objectives

Our underlying philosophy in the development and administration of Abraxas' annual and long-term compensation plans is to align the interests of our executive officers with those of Abraxas' stockholders. Key elements of this philosophy are:

- Establishing compensation plans that deliver base salaries which are competitive with companies in our industry, within Abraxas' budgetary constraints and commensurate with Abraxas' salary structure.
- Rewarding outstanding performance particularly where such performance is reflected by an increase in Abraxas' Net Asset Value, as adjusted for changes in oil and gas prices.
- Providing equity-based incentives to ensure motivation over the long-term to respond to Abraxas' business challenges and opportunities as owners rather than just as employees.

The compensation currently paid to Abraxas' executive officers consists of three core elements: base salary, annual bonuses under a performance-based, non-equity incentive plan and long-term equity based awards granted pursuant to our 2005 Employee Long-Term Equity Incentive Plan, which we refer to as the 2005 Employee Plan, plus other employee benefits generally available to all employees of Abraxas.

We believe these elements support our underlying philosophy of aligning the interests of our executive officers with those of Abraxas' stockholders by providing the executive officers a competitive salary, an opportunity for annual bonuses, and equity-based incentives to ensure motivation over the long-term. We view the three core elements of compensation as related but distinct. Although we review total compensation, we do not believe that significant compensation derived from one component of compensation should increase or reduce compensation from another component. We determine the appropriate level for each component of compensation separately. We have not adopted any formal or informal policies or guidelines for allocating compensation among long-term incentives and annual base salary and bonuses, between cash and non-cash compensation, or among different forms of non-cash compensation; however, we do consider the age, tenure and seniority of each executive officer in making compensation decisions. Abraxas' Board has adopted stock ownership guidelines. Please read "Stock Ownership Guidelines" for more information.

Abraxas does not have any other deferred compensation programs or supplemental executive retirement plans and no benefits are provided to Abraxas' executive officers that are not otherwise available to all employees of Abraxas, and no benefits are valued in excess of $10,000 per employee per year.

Elements of Executive Compensation

Executive compensation consists of the following elements:

Base Salary. In determining base salaries for the executive officers of Abraxas, we aim to set base salaries at a level we believe enables us to hire and retain individuals in a competitive environment and to reward individual performance and contribution to our overall business goals. In addition, we take into consideration the responsibilities of each executive officer and determine compensation appropriate for the positions held and expectations of services rendered during the year. We compare the salary structure of Abraxas to a group of exploration and production companies included in the William M. Mercer 2010 Energy Compensation Survey, which we refer to as the Mercer Energy Survey. We use the Mercer Energy Survey as a market check to ensure that we are paying competitive base salaries.

Abraxas' salary range is set by reference to the salaries paid by other companies in our industry considering the responsibilities and expectations of each executive officer while remaining within Abraxas' budgetary constraints. We utilize salary information from other companies in our industry to compare Abraxas' salary structure with those other companies that compete with Abraxas for executives but without targeting salaries to be higher, lower or approximately the same as those in our industry. We believe that the base salary levels for our executive officers are consistent with the practices of companies in our industry and increases in base salary levels from time to time are designed to reflect competitive practices in the industry, individual performance and the officer's contribution to our overall business goals. Individual performance and contribution to the overall business goals of Abraxas are subjective measures and evaluated by Mr. Watson and the Compensation Committee and, with respect to Mr. Watson, only the Compensation Committee.

The base salaries paid to our named executive officers in 2010 are set forth below in the Summary Compensation Table. For 2010, base salaries, paid as cash compensation, were $1,189,875 with Mr. Watson receiving $360,500. We believe that the base salaries paid achieved our objectives.

Annual Bonuses. Abraxas' current bonus plan was adopted by our Board of Directors in 2003, and later amended to include all of our executive officers. The purpose of the bonus plan is to create financial incentives for our executive officers that are tied directly to increases in Net Asset Value, or NAV, per share of Abraxas common stock. We chose NAV as the foundation of the bonus plan because we believe that NAV equates to the value of Abraxas' oil and gas reserve base, giving risked credit for non-proven reserves, and adjusted for other assets and liabilities, including long-term debt. We believe that NAV is a better indicator of the health of Abraxas than its stock price, as the success of finding oil and gas is directly reflected in our NAV, while our stock price can be influenced by a number of factors outside the control of the executive officers of Abraxas. In addition, many exploration and production analysts use NAV per share comparisons to establish price targets for the companies they follow. Under the bonus plan, NAV is calculated at each year-end after receipt of the reserve report from our independent petroleum engineering firm and the audited financials, subject to certain adjustments, as follows:

Net Asset Value Calculation:	
	PV-10 Proved Reserves
+	PV-10 Probable Reserves
+	Property & Equipment
+	Acreage
+	Other Assets
±	Net Working Capital
−	Debt
=	Net Asset Value ("NAV")
÷	Shares Outstanding
=	NAV per share

The proved and probable reserves are estimated at year-end by our independent petroleum engineering firm of DeGolyer and MacNaughton in accordance with guidelines published by the Society of Petroleum Engineers, and all other items in the NAV calculation are derived from our year-end audited financials. PV-10 is the estimated present value of the future net revenues from our 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. Due to our net loss carry-forwards and the tax basis of our properties, there is no impact of income taxes on our PV-10 calculation. As a result, there is no difference between the standardized measure of our oil and gas reserves, which is a GAAP financial measure, and the PV-10 of our oil and gas reserves.

The annual bonuses are calculated by the percentage increase in the current year-end NAV per share over the previous year-end NAV per share up to the first 10%; after 10% has been achieved, all excess percentage increases are doubled, with a maximum award for any one-year of 70% of the executive officer's base annual salary. For example, if the percentage increase in NAV for a given year was 15%, the calculated bonus would be equal to 20% of the executive officer's annual base salary. In order to compare NAV year-over-year, the current year-end PV-10 for proved and probable reserves are calculated with commodity prices used in the previous year-end PV-10 calculations. Then, for the ensuing year, the PV-10 for proved and probable reserves are calculated with current commodity prices to establish the NAV per share at the beginning of a given year, thus the difference between the calculated NAV per share at the end of a given year and the calculated NAV per share at the beginning of the following year.

In the first quarter of each year, the NAV per share for the prior year-end is calculated after reserves are estimated and audited financial statements are available. Mr. Watson then submits the annual bonus calculation to the Compensation Committee for review and discussion.

At the beginning of 2010, the calculated NAV per share was $0.57 utilizing commodity prices as of December 31, 2009 and the calculated NAV per share at the end of 2010 (utilizing commodity prices as of December 31, 2009) was $0.63, an 11% increase. As a result, the Compensation Committee recommended annual bonus awards for our executive officers, and the board approved these annual bonus awards at its meeting on March 15, 2011. The following table details the 2010 bonus earned by our named executive officers:

Name	Base Salary(1)	Bonus Award Achieved (Percentage of Salary)(2)	Maximum Award (Percentage of Salary)	Annual Bonus Awarded Under the Annual Bonus Plan
Robert L.G. Watson	$364,000	12.6%	70%	$45,864
Chris E. Williford	222,500	12.6%	70%	28,035
Lee T. Billingsley	207,000	12.6%	70%	26,082
William H. Wallace	207,000	12.6%	70%	26,082
Barbara M. Stuckey	207,000	12.6%	70%	26,082

(1) Base annual salaries in effect at the end of the year.
(2) 11% increase in NAV: 1% for the first 10%, then 2% for each percent increase (10 + (1.3 x 2)) = 12.6%.

The awards are reflected in the Grants of Plan-Based Awards table in the "Estimated Future Payouts Under Non-Equity Incentive Plan Awards" columns and in the Summary Compensation Table as earned in the "Non-Equity Incentive Plan Compensation" column.

The Compensation Committee has the discretion to defer all or any part of any bonus to future years, to pay all or any portion of any bonus, or deferred bonus, in shares of Abraxas common stock and has the discretion to pay bonuses even if no bonus would be payable under the bonus plan, and further has the discretion not to pay bonuses even if a bonus was earned under the bonus plan. In the past, the Committee has elected to pay a portion of the annual bonus in shares of Abraxas common stock and may continue to do so in the future. The Committee reviews the cash position of the Company and the amount of the annual bonus when making such determinations. The Compensation Committee also has the discretion to pay bonuses outside of this plan.

Long-Term Equity Incentives. Our executive officers are eligible to receive long-term equity incentives under our 2005 Employee Plan.

In determining whether to grant long-term incentive awards, such awards will be substantially contingent upon the conclusion of Mr. Watson and the Board of Directors (and only the Board of Directors, with respect to awards made to

Mr. Watson) as to whether individual and management's collective efforts have produced attractive long-term returns to Abraxas stockholders by increasing the market price of our common stock over time. In determining whether to grant long-term incentive awards, we anticipate that neither Mr. Watson nor the Board of Directors will have specific numerical targets, but rather will make a subjective determination based upon the state of the oil and gas exploration and production industry and other general economic factors at the time of their evaluation.

In the first quarter of each year, Mr. Watson submits his recommendations for long-term equity incentive awards to the Compensation Committee based upon his subjective evaluation of the individual performance of each executive officer, except himself. Mr. Watson also factors in the quantity and value of the long-term incentives that each executive officer has been previously awarded. The Compensation Committee reviews and discusses Mr. Watson's recommendations and makes final determinations as to such awards. For awards made to Mr. Watson, the Compensation Committee subjectively evaluates Mr. Watson's performance and, in their sole authority, determines, how many, if any, long-term equity incentive awards to grant to Mr. Watson. The Compensation Committee also considers the quantity and value of the long-term equity incentive awards previously granted to Mr. Watson when considering making awards to him. In determining whether to grant long-term equity incentive awards, we seek to ensure that the total compensation package, including cash compensation, is comparable to other companies in our industry, yet such awards are substantially contingent upon the conclusion of Mr. Watson and the Compensation Committee, as to whether individual and management's collective efforts have produced attractive long-term returns to Abraxas stockholders. We also consider past grants to each executive officer and the level to which such past grants are (or are not) "in-the-money."

Abraxas has historically granted long-term equity incentives after Mr. Watson presents his recommendations to the Compensation Committee in the first quarter; however, we have not granted long-term equity incentives every year and we have awarded long-term equity incentive awards at other times during the year, principally in the event of a new hire, substantial promotion or significant event, such as the completion of a financing transaction or an accretive acquisition. We believe that such events warrant the granting of awards outside the normal course of business as these events are significant to the future success of Abraxas. We do not time award grants in coordination with the release of material non-public information.

2005 Employee Plan. Abraxas' 2005 Employee Plan, which was approved by our stockholders at the 2006 annual meeting and amended by our stockholders at the 2008 annual meeting and at a special meeting held on October 5, 2009, authorizes us to grant incentive stock options, non-qualified stock options and shares of restricted stock to our executive officers, as well as to all employees of Abraxas. We use equity incentives as a form of long-term compensation because it provides our executive officers an opportunity to acquire an equity interest in Abraxas and further aligns their interest with those of our stockholders. Options grants generally have a term of 10 years and vest in equal increments over four years. Restricted stock grants vest in accordance with each individual grant agreement. Vesting is accelerated in certain events described under "Employment Agreements and Potential Payments Upon Termination or Change in Control."

The purposes of this plan are to employ and retain qualified and competent personnel and to promote the growth and success of Abraxas, which can be accomplished by aligning the long-term interests of the executive officers with those of the stockholders by providing the executive officers an opportunity to acquire an equity interest in Abraxas. All grants are made with an exercise price of no less than 100% of the fair market value on the date of such grant.

A total of 5,200,000 shares of Abraxas common stock have been reserved under the 2005 Employee Plan, subject to adjustment following certain events, such as stock splits. The maximum annual award for any one employee is 500,000 shares of Abraxas common stock. If options, as opposed to restricted stock, are awarded, the exercise price shall be no less than 100% of the fair market value on the date of the award, unless the employee is awarded incentive stock options and at the time of the award, owns more than 10% of the voting power of all classes of stock of Abraxas. Under this circumstance, the exercise price shall be no less than 110% of the fair market value on the date of the award. Option terms and vesting schedules are at the discretion of the Compensation Committee.

Employment Contracts, Change in Control Arrangements and Certain Other Matters. We provide the opportunity for our executive officers to be protected under the severance and change in control provisions contained in their employment agreements. We believe that these provisions help us to attract and retain an appropriate caliber of talent for these positions. Our severance and change in control provisions for the executive officers are summarized in "Employment Agreements and Potential Payments Upon Termination or Change in Control" below. We believe that our severance and change in control provisions are consistent with the programs and levels of severance and post employment compensation of other companies in our industry and believe that these arrangements are reasonable.

Other Employee Benefits. Abraxas' executive officers are eligible to participate in all of our employee benefit plans, such as medical, dental, group life and long-term disability insurance, in each case on the same basis as other employees. In addition to employee group life insurance, Abraxas has a key-man life insurance policy on Mr. Watson. Abraxas' executive officers are also eligible to participate in our 401(k) plan on the same basis as other employees. In 2008, Abraxas adopted the safe harbor provision for its 401(k) plan which requires Abraxas to contribute a fixed match to each participating employee's contributions to the plan. The fixed match is set at the rate of dollar for dollar for 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%. The fixed match is contributed in the form of Abraxas common stock. An 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 Abraxas to make additional contributions to each participating employee's plan. The employee contribution limit for 2010 was $16,500 for employees under the age of 50 and $22,000 for employees 50 years of age or older. The Board of Directors has also suggested a cap on the amount (or percentage) of Abraxas common stock that each employee should own in their individual 401(k) account to encourage diversification. The maximum suggested percentage has been set at 20% and each employee is encouraged to reduce their ownership of Abraxas common stock in their 401(k) account in the event such employee is over the suggested limit.

2011 Compensation Decisions

Base Salaries. In general, base salaries for 2011 increased approximately 5% from 2010 for our named executive officers to provide for merit increases and to adjust for increases in the cost of living.

Long-Term Equity Incentives. On March 15, 2011, Abraxas' Board of Directors awarded 510,000 options and 35,000 shares of restricted stock to employees of Abraxas, of which 180,000 options and 9,749 shares of restricted stock were awarded to our named executive officers.

Assessment of Compensation Policies and Practices

During 2009 and early 2010, the Company and the Compensation Committee conducted an in-depth risk assessment of the Company's compensation policies and practices in response to public and regulatory concerns about the link between incentive compensation and excessive risk taking by companies. The Company and the Committee concluded that our compensation program does not motivate imprudent risk taking. In this regard, the Committee believes that:

- The Company's annual incentive compensation is based on performance metrics that promote a disciplined approach towards the long-term goals of the Company;
- The Company does not offer significant short-term incentives that might drive high-risk investments at the expense of the long-term value of the Company;
- The Company's compensation programs are weighted towards offering long-term incentives that reward sustainable performance, especially when considering the Company's stock ownership guidelines for executive officers;
- The Company's compensation awards are capped at reasonable levels, as determined by a review of the Company's financial position and prospects, as well as the compensation offered by companies in our industry; and
- The Board's high level of involvement in approving material investments and capital expenditures helps avoid imprudent risk taking.

The Company's compensation policies and practices were evaluated to ensure that they do not foster risk taking above the level of risk associated with the Company's business and the Company concluded that it has a balanced pay and performance program and that the risks arising from its compensation policies and practices are not reasonably likely to have a material adverse effect on the Company.

Impact of Regulatory Requirements

Deductibility of Executive Compensation. In 1993, the federal tax laws were amended to limit the deduction a publicly-held company is allowed for compensation paid to the chief executive officer and to the four most highly compensated executive officers other than the chief executive officer. Generally, amounts paid in excess of $1.0 million to a covered executive, other than performance-based compensation, cannot be deducted. In order to constitute performance-based compensation for purposes of the tax law, stockholders must approve the performance measures. Since Abraxas does not anticipate that the compensation for any executive officer will exceed the $1.0 million threshold in the near term, stockholder approval necessary to maintain the tax deductibility of compensation at or above that level is not being requested. We will reconsider this matter if compensation levels approach this threshold, in light of the tax laws then in effect. We will consider ways to maximize the deductibility of executive compensation, while retaining the discretion necessary to compensate executive officers in a manner commensurate with performance and the competitive environment for executive talent.

Non-Qualified Deferred Compensation. On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law, changing the tax rules applicable to non-qualified deferred compensation arrangements. We believe we are in compliance with the statutory provisions which were effective January 1, 2005 and the regulations which became effective on January 1, 2009.

Accounting for Stock-Based Compensation. On October 1, 2005 we began accounting for stock-based compensation in accordance with the requirements of FASB ASC Topic 718 for all of our stock-based compensation plans. See note 8 of the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on March 16, 2011 for a discussion of all assumptions made in the calculation of this amount.

Policy on Recovery of Compensation. Our chief executive officer and chief financial officer are required to repay certain bonuses and stock-based compensation they receive if we are required to restate our financial statements as a result of misconduct as required by Section 304 of the Sarbanes-Oxley Act of 2002.

COMPENSATION COMMITTEE REPORT

The Compensation Committee of Abraxas has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this proxy statement.

This report is submitted by the members of the Compensation Committee.

Ralph F. Cox, Chairman
Harold D. Carter
Dennis E. Logue

SUMMARY COMPENSATION TABLE

The following table sets forth a summary of compensation paid to each of our named executive officers for the last three fiscal years.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Option Awards ($)(4)	Non-Equity Incentive Plan Compensation ($)(5)	All Other Compensation ($)(6)	Total ($)(7)
Robert L.G. Watson	2010	360,500	14,000	—	137,485	45,864	8,575	566,424
President, Chief Executive	2009	350,000	13,462	105,824	429,048	—	12,250	910,584
Officer and Chairman of the Board	2008	348,250	13,462	8,638	—	—	10,250	380,600
Chris E. Williford	2010	220,375	8,558	—	91,656	28,035	8,013	356,637
Executive Vice President, Chief	2009	214,000	8,231	52,692	120,549	—	7,490	402,962
Financial Officer and Treasurer	2008	212,750	8,231	3,162	—	—	7,245	231,388
Lee T. Billingsley	2010	205,000	7,962	—	91,656	26,082	7,454	338,154
Vice President—Exploration	2009	199,000	7,654	52,839	120,549	—	6,965	387,007
	2008	198,000	7,654	3,434	—	—	10,250	219,338
William H. Wallace	2010	205,000	7,962	—	91,656	26,082	7,454	338,154
Vice President—Operations	2009	199,000	7,654	52,839	120,549	—	6,965	387,007
	2008	198,000	7,654	12,450	—	—	10,250	228,354
Barbara M. Stuckey	2010	199,000	7,962	—	91,656	26,082	7,244	331,944
Vice President—Corporate Finance	2009	167,000	6,731	80,344	262,408	—	5,845	522,328

(1) The amounts in this column include any 401(k) plan account contributions made by the named executive officer.

(2) The amounts in this column reflect a discretionary holiday bonus.

(3) The amounts in this column reflect the aggregate grant date fair value of stock awards granted during a given year to the named executive officer calculated in accordance with FASB ASC Topic 718. See note 8 of the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on March 16, 2011 for a discussion of all assumptions made in the calculation of this amount. Amounts for the year ended December 31, 2008 have been recomputed to facilitate year-to-year comparisons.

(4) The amounts in this column reflect the aggregate grant date fair value of options granted during a given year to the named executive officer calculated in accordance with FASB ASC Topic 718. See note 8 of the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on March 16, 2011 for a discussion of all assumptions made in the calculation of this amount.

(5) The amounts in this column represent cash bonuses earned under the annual bonus plan.

(6) The amounts in this column represent contributions by Abraxas to the named executive officer's 401(k) plan account.

(7) The dollar value in this column for each named executive officer represents the sum of all compensation reflected in the previous columns.

GRANTS OF PLAN-BASED AWARDS

The following table provides information with regard to grants of non-equity incentive compensation and all other stock awards to our named executive officers. We do not have an equity incentive plan; therefore, these columns have been omitted from the following table.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/share)	Grant Date Fair Value of Stock and Option Awards ($)(3)
		Threshold ($)	Target ($)	Maximum ($)				
Robert L.G. Watson	n/a(1)	—	45,864	254,800				
	03/16/2010(2)					90,000	2.09	137,485
Chris E. Williford	n/a(1)	—	28,035	155,750				
	03/16/2010(2)					60,000	2.09	91,656
Lee T. Billingsley	n/a(1)	—	26,082	144,900				
	03/16/2010(2)					60,000	2.09	91,656
William H. Wallace	n/a(1)	—	26,082	144,900				
	03/16/2010(2)					60,000	2.09	91,656
Barbara M. Stuckey	n/a(1)	—	26,082	144,900				
	03/16/2010(2)					60,000	2.09	91,656

(1) Awards potentially payable under our annual bonus plan. The annual bonus plan does not provide for a threshold level as the bonuses under the plan can range from 0 to the maximum, which equals 70% of the named executive officers base salary. The target amount was not determinable on the date of grant; therefore, the amount set forth in the target column reflects the amount each named executive officer earned under the plan in 2010, as a representative amount. Please see the discussion under "Compensation Discussion and Analysis—Elements of Executive Compensation—Annual Bonuses" for more information. During 2010, our named executive officers earned an aggregate of $152,145 in bonuses under the annual bonus plan. Please refer to column 5 of the Summary Compensation Table.

(2) The closing price of Abraxas' common stock on the grant date was $2.09.

(3) The amounts in this column reflect the aggregate grant date fair value of stock awards and options granted in 2010 to the named executive officer calculated in accordance with FASB ASC Topic 718. See note 8 of the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on March 16, 2011 for a discussion of all assumptions made in the calculation of this amount.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

The following table provides information concerning outstanding equity awards at December 31, 2010 for our named executive officers. We do not have an equity incentive plan; therefore, these columns have been omitted from the following table.

	OPTION AWARDS				STOCK AWARDS	
Name	Number of Securities Underlying Unexercised Options (Exercisable)	Number of Securities Underlying Unexercised Options (Unexercisable)(1)	Option Exercise Price ($)	Option Expiration Date	Number of Shares of Stock That Have Not Vested(3)	Market Value of Shares of Stock That Have Not Vested ($)(4)
Robert L.G. Watson	30,000		0.66(2)	03/23/2011		
	30,000		4.83(2)	03/23/2011		
	6,856		0.66(2)	09/17/2011		
	6,857		2.21(2)	09/17/2011		
	90,000		0.65	11/22/2012		
	100,000		4.59	09/13/2015		
	31,218	10,406	3.60	08/28/2017		
	31,250	93,750	0.99	03/17/2019		
	66,938	200,812	1.75	10/05/2019		
		90,000	2.09	03/16/2020		
					50,988	233,015
Chris E. Williford	20,000		0.66	03/23/2011		
	43,000		0.65	11/22/2012		
	100,000		4.59	09/13/2015		
	11,425	3,808	3.60	08/28/2017		
	12,500	37,500	0.99	03/17/2019		
	16,735	50,202	1.75	10/05/2019		
		60,000	2.09	03/16/2020		
					24,187	110,535
Lee T. Billingsley	22,000		0.65	11/22/2012		
	15,000		0.68	04/24/2013		
	50,000		4.59	09/13/2015		
	12,408	4,135	3.60	08/28/2017		
	12,500	37,500	0.99	03/17/2019		
	16,735	50,202	1.75	10/05/2019		
		60,000	2.09	03/16/2020		
					24,504	111,983
William H. Wallace	15,000		0.66	03/23/2011		
	22,000		0.65	11/22/2012		
	15,000		0.68	04/24/2013		
	50,000		4.59	09/13/2015		
	14,190	4,730	3.60	08/28/2017		
	12,500	37,500	0.99	03/17/2019		
	16,735	50,202	1.75	10/05/2019		
		60,000	2.09	03/16/2020		
					31,747	145,084
Barbara M. Stuckey	25,000		4.59	09/13/2015		
	5,000		6.05	02/24/2016		
	7,641	2,547	3.60	08/28/2017		
	12,500	37,500	0.99	03/17/2019		
	44,625	133,875	1.75	10/05/2019		
		60,000	2.09	03/16/2020		
					34,205	156,317

(1) Options vest in twenty-five percent (25%) increments each year for four (4) years on the anniversary of the grant date.
(2) On December 6, 2002, the Board of Directors approved a plan pursuant to which the price of each outstanding stock option granted to employees of Abraxas with an exercise price greater than $0.66 per share was reduced to $0.66 per share. However, only one-half of Mr. Watson's options were re-priced at $0.66. The re-pricing was approved in connection with Abraxas' financial restructuring which was consummated in January 2003. As part of the negotiations that Abraxas had undertaken with the beneficial holder of the largest block of Abraxas' then outstanding second lien notes, the holder conditioned its participation in the exchange offer for the second lien notes on the re-pricing. Because the Board believed that the financial restructuring, including the exchange offer, represented the best alternative available to Abraxas to reduce its long term indebtedness and to increase its liquidity, the Board approved the re-pricing. The effectiveness of the re-pricing was conditioned upon the consummation of the financial restructuring which occurred on January 23, 2003.
(3) In general, stock awards vest in twenty-five percent (25%) increments each year for four (4) years on the anniversary of the grant date. As each increment vests, a new award equal to the most recently vested portion is granted and vests on the 4th anniversary after the grant date.
(4) The market value was calculated from the closing price of Abraxas' common stock on December 31, 2010 of $4.57 per share multiplied by the number of shares of stock that had not vested as of December 31, 2010.

OPTION EXERCISES AND STOCK VESTED

The following table provides information concerning exercises of stock options and other stock awards by our named executive officers during the fiscal year ended December 31, 2010.

	OPTION AWARDS		STOCK AWARDS	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting	Value Realized on Vesting ($)
Robert L.G. Watson	120,000(1)	164,400(4)	20,459	41,718(7)
Chris E. Williford	40,000(2)	69,200(5)	9,975	20,130(8)
Lee T. Billingsley	15,000(3)	34,950(6)	10,084	20,402(9)
William H. Wallace	—	—	13,706	29,457(10)
Barbara M. Stuckey	—	—	14,424	28,560(11)

(1) Of this amount, 34,644 shares were utilized as payment of the exercise price.
(2) Of this amount, 11,046 shares were utilized as payment of the exercise price.
(3) Of this amount, 3,311 shares were utilized as payment of the exercise price.
(4) These options were exercised on May 26, 2010, of which 60,000 had an exercise price of $0.66 and 60,000 had an exercise price of $1.38. The closing price of Abraxas' common stock on the day prior to exercise was $2.39 per share, for a realized value of $1.73 and $1.01, respectively.
(5) These options were exercised on May 26, 2010. The exercise price was $0.66 and the closing price of Abraxas' common stock on the day prior to exercise was $2.39, for a realized value of $1.73 per share.
(6) These options were exercised on October 25, 2010. The exercise price was $0.66 and the closing price of Abraxas' common stock on that date was $2.99, for a realized value of $2.33 per share.
(7) Of these stock awards, 6,375 vested on January 2, 2010, 10,615 vested on January 31, 2010 and 3,469 vested on August 28, 2010 and the closing price of Abraxas' common stock on those dates was $1.92, $1.96 and $2.50, respectively.
(8) Of these stock awards, 2,657 vested on January 2, 2010, 6,049 vested on January 31, 2010 and 1,269 vested on August 28, 2010 and the closing price of Abraxas' common stock on those dates was $1.92, $1.96 and $2.50, respectively.
(9) Of these stock awards, 2,657 vested on January 2, 2010, 6,049 vested on January 31, 2010 and 1,378 vested on August 28, 2010 and the closing price of Abraxas' common stock on those dates was $1.92, $1.96 and $2.50, respectively.
(10) Of these stock awards, 2,657 vested on January 2, 2010, 6,049 vested on January 31, 2010 and 5,000 vested on August 28, 2010 and the closing price of Abraxas' common stock on those dates was $1.92, $1.96 and $2.50, respectively.
(11) Of these stock awards, 4,250 vested on January 2, 2010, 9,325 vested on January 31, 2010 and 849 vested on August 28, 2010 and the closing price of Abraxas' common stock on those dates was $1.92, $1.96 and $2.50, respectively.

Pension Benefits

Abraxas does not sponsor any pension benefit plans and none of the named executive officers contribute to such a plan.

Non-Qualified Deferred Compensation

Abraxas does not sponsor any non-qualified defined compensation plans or other non-qualified deferred compensation plans and none of the named executive officers contribute to any such plans.

Stock Ownership Guidelines

Abraxas' Board has established stock ownership guidelines to strengthen the alignment of director and executive officer interests with those of our stockholders. As of December 31, 2010, we had eight non-employee directors and six executive officers subject to the stock ownership guidelines. Under the guidelines below, each director and officer is precluded from selling any shares of Abraxas common stock until the director or officer satisfies the ownership guidelines set forth in the following table. Satisfaction of the ownership guidelines will fluctuate with the market value of Abraxas common stock.

Position	Stock Ownership Guidelines
Chief Executive Officer	5x annual base salary
All other Executive Officers	3x annual base salary
Non-employee Directors	3x all fees received during the prior 12-month period, including the value of common shares awarded in lieu of cash payments at the time of issuance

Abraxas' Board has discretion to review special situations; however, non-compliance without board approval can result in the loss of future bonuses and discretionary stock-based compensation. As of December 31, 2010, the market value of Abraxas common stock was $4.57 per share. As an example, Mr. Watson, our chief executive officer, is required to own 398,249 shares of Abraxas common stock to meet the stock ownership guidelines at this price. As of December 31, 2010, five officers and six directors had satisfied the minimum stock ownership guidelines.

Employment Agreements and Potential Payments Upon Termination or Change in Control

Abraxas has entered into employment agreements with each of our named executive officers pursuant to which each will receive compensation as determined from time to time by the Board in its sole discretion. Abraxas has also established the Abraxas Petroleum Corporation Severance Plan, effective December 31, 2008, for all employees that are not subject to an employment agreement. This plan provides severance benefits in the event of a change in control and for certain other changes in conditions of employment. The affected employees would be entitled to receive one month of base salary for each year of service with Abraxas, up to a maximum of 12 months.

The employment agreements for Messrs. Watson and Williford are scheduled to terminate on December 21, 2011, and are automatically extended for additional one-year terms unless Abraxas gives 120 days notice of its intention not to renew the employment agreement. The employment agreements for Mr. Wallace, Dr. Billingsley and Ms. Stuckey are scheduled to terminate on December 31, 2011, and are automatically extended for an additional year if by December 1 neither Abraxas nor Mr. Wallace, Dr. Billingsley or Ms. Stuckey, as the case may be, has given notice to the contrary.

The employment agreements contain the following defined terms:

"Cause" means termination upon

(i) the continued failure by the officer to substantially perform his duties with Abraxas (other than any such failure resulting from his incapacity due to physical or mental illness or any such actual or anticipated failure resulting from termination by him for Good Reason) after a written demand for substantial performance is delivered to the officer by the Board, which demand specifically identifies the manner in which the Board believes that he has not substantially performed his duties, or

(ii) the engaging by the officer in conduct which is demonstrably and materially injurious to the Company, monetarily or otherwise. The officer shall not be deemed to have been terminated for Cause unless and until the officer has been delivered a copy of a resolution duly adopted by the affirmative vote (which cannot be delegated) of not less than a majority of the members of the Board who are not officers of the Company at a meeting of the Board called and held for such purposes (after reasonable notice to the officer and an opportunity for the officer, together with the officer's counsel, to be heard before the Board), finding that in the good faith opinion of the Board, the officer was guilty of conduct set forth above in clauses (i) or (ii) above and specifying the particulars thereof in detail.

"Change in Control" means the occurrence of

(i) any "person" or "group" (as such terms are used in Section 13(d) and 14(d) of the Securities Exchange Act of 1934, as amended, (the "Exchange Act")) becoming the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), except that a person shall be deemed to be the "beneficial owner" of all shares that any such person has the right to acquire pursuant to any agreement or arrangement or upon exercise of conversion rights, warrants, options or otherwise, without regard to the sixty day period referred to in such Rule), directly or indirectly, of securities representing 20% or more of the combined voting power of the Company's then outstanding securities,

(ii) any person or group making a tender offer or an exchange offer for 20% or more of the combined voting power of the Company's then outstanding securities,

(iii) at any time during any period of two consecutive years, individuals who at the beginning of such period constituted the Board and any new directors, whose election by the Board or nomination for election by the Company's stockholders was approved by a vote of at least two-thirds (2/3) of the Company directors then still in office who either were the Company directors at the beginning of the period or whose election or nomination for election was previously so approved ("Current Directors"), ceasing for any reason to constitute a majority thereof,

(iv) the Company consolidating, merging or exchanging securities with any other entity and the stockholders of the Company immediately before the effective time of such transaction not beneficially owning, immediately after the effective time of such transaction, shares entitling such stockholders to a majority of all votes (without consideration of the rights of any class of stock entitled to elect directors by a separate class vote) to which all stockholders of the corporation issuing cash or securities in the consolidation, merger or share exchange would be entitled for the purpose of electing directors or where the Current Directors immediately after the effective time of the consolidation, merger or share exchange not constituting a majority of the Board of Directors of the corporation issuing cash or securities in the consolidation, merger or share exchange, or

(v) any person or group acquiring 50% or more of the Company's assets.

"Disability" means the incapacity of the officer due to physical or mental illness which causes the officer to have been absent from the full-time performance of his duties with the Company for six consecutive months, and within 30 days after the Company gives the officer written notice of termination, the officer has not returned to the full-time performance of his duties.

"Good Reason" means, without the officer's express written consent, any of the following:

(i) a material adverse alteration in the nature or status of his position, duties or responsibilities,

(ii) a reduction in his current annual base salary,

(iii) a change in the principal place of his employment to a location more than twenty-five (25) miles from the Company's current principal place of employment, excluding required travel on the Company's business to an extent substantially consistent with the officer's present business travel obligations,

(iv) the failure by the Company, without his consent, to pay to him any portion of his current compensation, or to pay to him any portion of any deferred compensation, within ten (10) days of the date any such compensation payment is due,

(v) the failure by the Company to continue in effect any compensation plan in which he participates, or any substitute plans or the failure by the Company to continue his participation therein on the same basis, both in terms of the amount of benefits provided and the level of his participation relative to other participants, as existing,

(vi) the failure by the Company to continue to provide him with benefits at least as favorable to those enjoyed by him under any of the Company's pension, life insurance, medical, health and accident, disability, deferred compensation or savings plans in which he is currently participating, the taking of any action by the Company which would directly or indirectly materially reduce any of such benefits or deprive the officer of any material fringe benefit enjoyed by him, or the failure by the Company to provide him with the number of paid vacation days to which he is entitled on the basis of the Company's practice with respect to him,

(vii) the failure of the Company to obtain a satisfactory agreement from any successor to assume and agree to perform his employment agreement, or

(viii) any purported termination of his employment which is not effected pursuant to the employment agreement's termination provisions.

"Retirement" means termination in accordance with the Company's retirement policy, generally applicable to its salaried employees or in accordance with any retirement arrangement established with the officer's consent with respect to himself.

If, during the term of the employment agreement for officer or any extension thereof, an officer's employment is terminated other than for Cause or Disability, by reason of the officer's death or Retirement, or by such officer for Good Reason, then such officer will be entitled to receive the following:

Watson and Williford: a lump sum payment equal to the greater of (a) his annual base salary for the last full year during which he was employed by Abraxas or (b) his annual base salary for the remainder of the term of his employment agreement.

Wallace, Billingsley and Stuckey: no provisions for termination of employment because at all times during the term of each officer's employment agreements, such officer's employment is at will and may be terminated by Abraxas for any reason without notice or cause. If, during the term of the employment agreement for each of Mr. Wallace, Dr. Billingsley or Ms. Stuckey or any extension thereof, a change in control occurs, then such officer will be entitled to an automatic extension of the term of the officer's employment agreement for a period of 36 months beyond the term in effect immediately before the change in control.

If, following a change in control, an officer's employment is terminated other than for Cause or Disability, by reason of the officer's death or Retirement or by such officer for Good Reason, then such terminated officer will be entitled to the following:

Watson and Williford: a lump sum payment equal to 2.99 times his annual base salary.

Wallace, Billingsley and Stuckey: a lump sum payment equal to three times his annual base salary.

If any lump sum payment to a named executive officer would individually or together with any other amounts paid or payable constitute an "excess parachute payment" within the meaning of Section 280G of the Internal Revenue Code of 1986, as amended, and applicable regulations thereunder, the amounts to be paid will be increased so that each named executive officer, as the case may be, will be entitled to receive the amount of compensation provided in his agreement after payment of the tax imposed by Section 280G.

In addition, unvested options that have been awarded to our named executive officers will vest upon any change in control. As of December 31, 2010, 1,084,669 options were unvested, all of which were "in-the-money" as of December 31, 2010.

The following table provides information concerning termination and change in control payments to each of our named executive officers as if the event occurred on December 31, 2010.

Termination and Change in Control Payments Table

Name	Type of Benefit	Before Change in Control Termination w/o Cause or for Good Reason ($)(1)	After Change in Control Termination w/o Cause or for Good Reason ($)(2)	Voluntary Termination ($)	Death / Disability ($)	Change in Control ($)(3)
Robert L.G. Watson	Severance pay	364,000	1,088,360	—	—	364,000
	Option acceleration					1,135,209
Chris E. Williford	Severance pay	222,500	665,275	—	—	222,500
	Option acceleration					428,313
Lee T. Billingsley	Severance pay	—	621,000	—	—	621,000
	Option acceleration					428,631
William H. Wallace	Severance pay	—	621,000	—	—	621,000
	Option acceleration					429,208
Barbara M. Stuckey	Severance pay	—	621,000	—	—	621,000
	Option acceleration					663,048

(1) These amounts reflect a lump sum payment equal to the officer's annual base salary as of December 31, 2010.
(2) These amounts reflect a lump sum payment equal to 2.99x (Watson and Williford) and 3.0x (Wallace, Billingsley and Stuckey) the named executive officer's annual base salary as of December 31, 2010.

(3) These amounts on the severance pay row reflect a 12-month extension (Watson and Williford) and a 36-month extension (Wallace, Billingsley and Stuckey) of each officer's respective employment agreement based on the named executive officer's annual base salary on December 31, 2010 and would be paid over the extension period. The amounts on the option acceleration row reflect 1,084,669 "in-the-money" options at a potential value of $2.84 per share (the difference between the fair market value on December 31, 2010 and the exercise price of the options).

Compensation of Directors

All compensation paid to directors is limited to non-employee directors. We use a combination of cash and stock-based incentive compensation to attract and retain qualified individuals to serve on the Board.

Compensation. Prior to April 2010, the annual retainer fee paid to each director was $20,000, $12,000 of which was paid in shares of Abraxas common stock and the remaining $8,000 was paid in cash. The number of shares issued to each non-employee director was calculated each quarter by dividing $3,000 by the closing price of our common stock on the date of each quarterly board meeting. In April 2010, the annual retainer fee was increased to $26,000 to be paid in four quarterly cash payments and in April 2011, the annual retainer fee was increased to $27,500 to be paid in four quarterly cash payments.

In addition, prior to April 2011, Abraxas paid each director $1,500 for each board meeting attended and $1,000 for each committee meeting attended. The chairman of the audit committee received an additional annual fee of $10,000, the chairman of the compensation committee received an additional annual fee of $5,000 and the chairman of the governance and nominating committee received an additional annual fee of $2,000. In April 2011, certain fees were increased and each director will be paid $1,600 for each board meeting attended and $1,100 for each committee meeting attended. The chairman of the audit committee will receive an additional annual fee of $10,500, the chairman of the compensation committee will receive an additional annual fee of $5,300 and the chairman of the governance and nominating committee will receive an additional annual fee of $2,100.

Stock Options. Abraxas has awarded each director stock options, depending on each director's length of service, with exercise prices equal to the prevailing market prices at the time of issuance, ranging from $0.68 to $4.59 per share. Prior to April 2011, each year at the first regular board meeting following the annual meeting, Abraxas awarded each director 10,000 options, in accordance with the terms of the 2005 Directors Plan. In April 2011, the annual award was increased to 10,500 options. The amended 2005 Directors Plan reserves 1,500,000 shares of Abraxas common stock, subject to adjustment following certain events, such as stock splits. The maximum annual award for any one director is 100,000 shares. The exercise price of all options awarded is 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 Compensation Committee.

Unless otherwise provided in the applicable award agreement, vested awards granted under the 2005 Directors Plan shall expire, terminate, or otherwise be forfeited as follows:

- three months after the date the Company delivers a notice of termination of a participant's active status, other than in circumstances covered by the following three circumstances:
  - immediately upon termination for misconduct;
  - 12 months after the date of death; and
  - 36 months after the date on which the director ceased performing services as a result of retirement.

The following table sets forth a summary of compensation for the fiscal year ended December 31, 2010 that Abraxas paid to each director. Abraxas does not sponsor a pension benefits plan, a non-qualified deferred compensation plan or a non-equity incentive plan for its directors; therefore, these columns have been omitted from the following table. Except for reimbursement of travel expenses to attend board and committee meetings, no other or additional compensation for services were paid to any of the directors.

Director Compensation Table

Name	Fees Earned or Paid in Cash ($)(1)	Retainer Stock Awards ($)(2)	Restricted Stock and Option Awards ($)(3)	Total ($)(4)
C. Scott Bartlett, Jr.	44,250	3,000	23,502	70,752
Franklin A. Burke	31,500	3,000	23,502	58,002
Harold D. Carter	27,000	3,000	23,502	53,502
Ralph F. Cox	32,750	3,000	23,502	59,252
Dennis E. Logue	30,500	3,000	23,502	57,002
Brian L. Melton	31,500	3,000	23,502	58,002
Paul A. Powell, Jr.	31,500	3,000	23,502	58,002
Edward P. Russell	27,500	3,000	23,502	54,002

(1) This column represents the amounts paid in cash to each director.

(2) This column represents the dollar value of stock awarded to each director for the retainer fee attributable to the first quarter of 2010. On March 16, 2010, each director was awarded 1,435 vested shares of Abraxas common stock and the closing price on that date was $2.09 per share.

(3) The amounts in this column reflect the aggregate grant date fair value of stock awards and options granted in 2010 to each director calculated in accordance with FASB ASC Topic 718. See note 8 of the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on March 16, 2011 for a discussion of all assumptions made in the calculation of this amount.

(4) The dollar value in this column for each director represents the sum of all compensation reflected in the previous columns.

Outstanding Equity Awards at Fiscal Year End Table

The following table provides information concerning outstanding equity awards at December 31, 2010 for our directors.

	OPTION AWARDS			STOCK AWARDS	
Name	Number of Securities Underlying Unexercised Options (Exercisable)	Number of Securities Underlying Unexercised Options (Unexercisable)(1)	Option Exercise Price ($)	Number of Shares of Stock That Have Not Vested(2)	Market Value of Shares of Stock That Have Not Vested ($)(3)
C. Scott Bartlett, Jr.	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	—	37,500	0.99		
	10,000		2.36		
Franklin A. Burke	45,000		0.68		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	12,500	37,500	0.99		
	10,000		1.06		
	10,000		2.36		
Harold D. Carter	45,000		1.01		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	12,500	37,500	0.99		
	10,000		1.06		
	10,000		2.36		
Ralph F. Cox	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	12,500	37,500	0.99		
	10,000		1.06		
	10,000		2.36		
				12,750	58,268
Dennis E. Logue	58,000		0.68		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	12,500	37,500	0.99		
	10,000		1.06		
	10,000		2.36		
Brian L. Melton	18,750	56,250	1.64		
	10,000		2.36		
				12,750	58,268
Paul A. Powell, Jr.	10,000		2.75		
	45,000		4.59		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	12,500	37,500	0.99		
	10,000		1.06		
	10,000		2.36		
Edward P. Russell	18,750	56,250	1.64		
	10,000		2.36		

(1) The options awarded to each non-employee director at the first regular board meeting following the annual meeting vest immediately. Other option awards vest in twenty-five percent (25%) increments each year for four (4) years on the anniversary of the grant date.

(2) Stock awards vest in twenty-five percent (25%) increments each year for four (4) years on the anniversary of the grant date.

(3) The market value was calculated from the closing price of Abraxas' common stock on December 31, 2010 of $4.57 per share multiplied by the number of shares of stock that had not vested as of December 31, 2010.

Proxy Statement

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

General

On February 21, 2007, the Board of Directors adopted a formal written related person transaction approval policy, which sets out Abraxas' policies and procedures for the review, approval, or ratification of "related person transactions." For these purposes, a "related person" is a director, nominee for director, executive officer, or holder of more than 5% of our common stock, or any immediate family member of any of the foregoing. This policy applies to any financial transaction, arrangement or relationship or any series of similar financial transactions, arrangements or relationships in which Abraxas is a participant and in which a related person has a direct or indirect interest, other than the following:

- payment of compensation by Abraxas to a related person for the related person's service in the capacity or capacities that give rise to the person's status as a "related person;"
- transactions available to all employees or all stockholders on the same terms;
- purchases of supplies from Abraxas in the ordinary course of business at the same price and on the same terms as offered to any other purchasers, regardless of whether the transactions are required to be reported in Abraxas' filings with the SEC; and
- transactions which when aggregated with the amount of all other transactions between the related person and Abraxas involve less than $10,000 in a fiscal year.

Our Audit Committee is required to approve any related person transaction subject to this policy before commencement of the related person transaction, provided that if the related person transaction is identified after it commences, it shall be brought to the Audit Committee for ratification, amendment or rescission. The chairman of our Audit Committee has the authority to approve or take other actions in respect of any related person transaction that arises, or first becomes known, between meetings of the Audit Committee, provided that any action by the chairman must be reported to our Audit Committee at its next regularly scheduled meeting.

Our Audit Committee will analyze the following factors, in addition to any other factors the members of the Audit Committee deem appropriate, in determining whether to approve a related person transaction:

- whether the terms are fair to Abraxas;
- whether the transaction is material to Abraxas;
- the role the related person has played in arranging the related person transaction;
- the structure of the related person transaction; and
- the interest of all related persons in the related person transaction.

Transactions in 2010

Abraxas did not have any related party transactions in 2010.

Our Audit Committee may, in its sole discretion, approve or deny any related person transaction. Approval of a related person transaction may be conditioned upon Abraxas and the related person following certain procedures designated by the Audit Committee.

PROPOSAL TWO

RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Abraxas Board of Directors has selected BDO USA, LLP to serve as its independent registered public accounting firm for the fiscal year ending December 31, 2011. Although stockholder ratification is not required, the Board of Directors has directed that such appointment be submitted to the stockholders of Abraxas for ratification at the annual meeting. BDO USA, LLP provided audit services to Abraxas for the year ended December 31, 2010. A representative of BDO USA, LLP will be present at the annual meeting, will have an opportunity to make a statement if he or she desires to do so and will be available to respond to appropriate questions.

No report of BDO USA, LLP on Abraxas' financial statements for either of Abraxas' last two fiscal years contained any adverse opinion or disclaimer of opinion, nor was any such report qualified or modified as to uncertainty, audit scope or accounting principles.

In connection with the audits of Abraxas' financial statements for the last two fiscal years, there were no disagreements with BDO USA, LLP on any matters of accounting principles, financial statement disclosure or audit scope and procedures which, if not resolved to the satisfaction of BDO USA, LLP, would have caused the firm to make reference to the matter in its report. During Abraxas' last two fiscal years, there were no reportable events as described in Item 304(a)(1)(v) of Regulation S-K.

Assuming the presence of a quorum, the affirmative vote of the holders of a majority of the total votes cast is necessary to ratify the appointment of Abraxas' independent registered public accounting firm. The enclosed proxy card provides a means for stockholders to vote for the ratification of the selection of Abraxas' independent registered public accounting firm, to vote against it or to abstain from voting with respect to it. **If a stockholder executes and returns a proxy, but does not specify how the shares represented by such stockholder's proxy are to be voted, such shares will be voted FOR the ratification of selection of Abraxas' independent registered public accounting firm.** Abstentions will have the same legal effect as a vote against the proposal. Since this proposal is considered a "routine" matter, brokers will be permitted to vote on behalf of their clients, if no voting instructions are furnished.

The Board of Directors recommends a vote "FOR" the ratification of the selection of BDO USA, LLP, as Abraxas' independent registered public accounting firm for the fiscal year ending December 31, 2011.

AUDIT COMMITTEE REPORT

The Audit Committee represents and assists the Board in fulfilling its responsibilities for general oversight of the integrity of Abraxas' financial statements, Abraxas' compliance with legal and regulatory requirements, the independent auditor's qualifications and independence, the performance of Abraxas' internal audit function, and risk assessment and risk management. The Audit Committee manages Abraxas' relationship with its independent auditors (which report directly to the Audit Committee). The Audit Committee has the authority to obtain advice and assistance from outside legal, accounting or other advisors as the Audit Committee deems necessary to carry out its duties and receives appropriate funding, as determined by the Audit Committee, from Abraxas for such advice and assistance.

Abraxas' management is primarily responsible for Abraxas' internal control and financial reporting process. Abraxas' independent auditors, BDO USA, LLP, are responsible for performing an independent audit of Abraxas' consolidated financial statements and internal control over financial reporting, and issuing opinions on the conformity of those audited financial statements with United States generally accepted accounting principles. The Audit Committee monitors Abraxas' financial reporting process and reports to the Board on its findings.

In this context, the Audit Committee hereby reports as follows:

1. The Audit Committee has reviewed and discussed the audited financial statements with Abraxas' management.

2. The Audit Committee has discussed with the independent auditors the matters required to be discussed by the Statement on Auditing Standards No. 61, as amended (Codification of Statements on Auditing Standards, AU 380), as adopted by the Public Company Accounting Oversight Board ("PCAOB") in Rule 3200T.

3. The Audit Committee has received the written disclosures and the letter from the independent auditors required by the PCAOB regarding the independent auditors' communications with the Audit Committee concerning independence, and has discussed with the independent auditors their independence.

4. Based on the review and discussions referred to in paragraphs (1) through (3) above, the Audit Committee recommended to the Board, and the Board has approved, that the audited financial statements be included in Abraxas' Annual Report on Form 10-K for the year ended December 31, 2010, and for filing with the Securities and Exchange Commission.

This report is submitted by the members of the Audit Committee.

C. Scott Bartlett, Jr., Chairman
Franklin A. Burke
Paul A. Powell, Jr.
Brian L. Melton

PRINCIPAL AUDITOR FEES AND SERVICES

Audit Fees. The aggregate fees billed by BDO USA, LLP for professional services rendered for the audit of Abraxas' annual financial statements for the years ended December 31, 2010 and December 31, 2009 and the reviews of the condensed financial statements included in Abraxas' quarterly reports on Form 10-Q for the years ended December 31, 2010 and December 31, 2009, were $453,896 and $433,181, respectively.

Audit-Related Fees. The aggregate fees billed by BDO USA, LLP for assurance and related services that were reasonably related to the performance of the audit or review of Abraxas' financial statements which are not reported in "audit fees" above, for the years ended December 31, 2010 and December 31, 2009, were $0 and $31,530, respectively. The fees in 2009 were for services provided by BDO USA, LLP related to consulting services associated with technical accounting treatment of various transactions.

Tax Fees. The aggregate fees billed by BDO USA, LLP for professional services rendered for tax compliance, tax advice or tax planning for the years ended December 31, 2010 and December 31, 2009, were $6,500 and $0, respectively. The fees in 2010 were for services provided by BDO USA, LLP related to tax consulting.

All Other Fees. The aggregate fees billed by BDO USA, LLP for other services, exclusive of the fees disclosed above relating to financial statement audit and audit-related services and tax compliance, advice or planning, for the years ended December 31, 2010 and December 31, 2009, were $0 and $146,070, respectively. The fees in 2009 were for services provided by BDO USA, LLP related to Abraxas Energy Partners, L.P.'s registration statement, the merger of Abraxas Energy Partners, L.P. into a wholly-owned subsidiary of Abraxas and related proxy statement.

Consideration of Non-audit Services Provided by the Independent Auditors. The Audit Committee has considered whether the services provided for non-audit services are compatible with maintaining BDO USA, LLP's independence, and has concluded that the independence of such firm has been maintained.

AUDIT COMMITTEE PRE-APPROVAL POLICY

The Audit Committee's policy is to pre-approve all audit, audit-related and non-audit services provided by the independent registered public accounting firm. These services may include audit services, audit-related services, tax services and other services. The Audit Committee approved all of the fees described above. The Audit Committee may also pre-approve particular services on a case-by-case basis. The independent public accountants are required to periodically report to the Audit Committee regarding the extent of services provided by the independent public accountants in accordance with such pre-approval. The Audit Committee may also delegate pre-approval authority to one or more of its members. Such member(s) must report any decisions to the Audit Committee at the next scheduled meeting.

PROPOSAL THREE

ADVISORY VOTE ON EXECUTIVE COMPENSATION

Abraxas asks that you indicate your support for our executive compensation policies and practices as described in our Compensation Discussion and Analysis, accompanying tables and related narrative contained in this proxy statement beginning on page 16. Your vote is advisory and will not be binding on the Board of Directors; however, the Board of Directors will review the voting results and take them into consideration when making future decisions regarding executive compensation.

The Compensation Committee is responsible for executive compensation and works to structure a compensation plan that reflects Abraxas' underlying compensation philosophy of aligning the interests of our executive officers with those of our stockholders. Key elements of this philosophy are:

- Establishing compensation plans that deliver base salaries which are competitive with companies in our industry.
- Rewarding outstanding performance particularly where such performance is reflected by an increase in Abraxas' Net Asset Value.
- Providing equity-based incentives to ensure motivation over the long-term to respond to Abraxas' business challenges and opportunities as owners rather than just as employees.

The Board of Directors recommends a vote "FOR" the following resolution:

RESOLVED: That the stockholders approve, on an advisory basis, the compensation of Abraxas' executives named in the Summary Compensation Table, as disclosed in this proxy statement pursuant to the executive compensation disclosure rules of the Securities and Exchange Commission, which disclosure includes the Compensation Discussion and Analysis, the compensation tables and other executive compensation disclosures and related material set forth in this proxy statement.

PROPOSAL FOUR

FREQUENCY OF FUTURE ADVISORY VOTES ON EXECUTIVE COMPENSATION

The Dodd-Frank Wall Street Reform and Consumer Protection Act requires us to provide an advisory stockholder vote to determine how often to present the advisory stockholder vote to approve the compensation of our named executive officers (the "say-on-pay vote"). We must solicit your advisory vote on whether to have the say-on-pay vote every 1, 2, or 3 years. Stockholders may vote as to whether the say-on-pay vote should occur every 1, 2 or 3 years, or may abstain from voting on the matter. The frequency (every 1, 2 or 3 years) that receives the highest number of votes will be deemed to be the choice of the stockholders.

We value the opinion of our stockholders and welcome communication regarding our executive compensation policies and practices. After taking into account various considerations described below, we believe that a triennial vote will provide stockholders with the ability to express their views on our executive compensation policies and practices while providing us with an appropriate amount of time to consult with our stockholders and to consider their input.

Our executive compensation is administered by our Compensation Committee, as described in this proxy statement. Compensation decisions are complex and, with respect to our named executive officers, are disclosed in our proxy statement. We believe that establishing a three-year time frame for holding stockholder advisory votes on executive compensation will both enhance stockholder communication and provide the Compensation Committee time to consider, engage with and respond to stockholders, in terms of expressed concerns or other feedback. In addition, we also believe that a triennial vote is consistent with our long-term business strategy and gives the Compensation Committee sufficient time to measure long-term performance.

Although, as an advisory vote, this proposal is not binding upon Abraxas or its Board of Directors, the Board will carefully consider the stockholder vote on this matter.

While you have the opportunity to vote for every 1, 2 or 3 years, or abstain from voting on the frequency of future say-on-pay votes, the Board of Directors recommends that you vote for a frequency of every 3 years.

STOCKHOLDER PROPOSALS FOR 2012 ABRAXAS ANNUAL MEETING

Abraxas intends to hold its next annual meeting during the second quarter of 2012, according to its normal schedule. In order to be included in the proxy material for the 2012 Annual Meeting, Abraxas must receive eligible proposals from stockholders intended to be presented at the annual meeting on or before December 3, 2011, directed to the Abraxas Secretary at the address indicated on the first page of this proxy statement.

According to our Amended and Restated Bylaws, Abraxas must receive timely written notice of any stockholder nominations and proposals to be properly brought before the 2012 Annual Meeting. To be timely, such notice must be delivered to the Abraxas Secretary at the principal executive offices set forth on the first page of this proxy statement between February 5, 2012 and the close of business on March 6, 2012. The written notice must set forth, as to the stockholder giving the notice and the beneficial owner, if any, on whose behalf the nomination or proposal is made (i) the name and address of such stockholder, as they appear on Abraxas' books, and of such beneficial owner, if any, (ii) (a) the class or series and number of Abraxas shares which are, directly or indirectly, owned beneficially and of record by such stockholder and such beneficial owner, (b) any option, warrant, convertible security, stock appreciation right, or similar right with an exercise or conversion privilege or a settlement payment or mechanism at a price related to any class or series of Abraxas shares or with a value derived in whole or in part from the value of any class or series of Abraxas shares, whether or not such instrument or right shall be subject to settlement in the underlying class or series of Abraxas capital stock or otherwise (a "Derivative Instrument") directly or indirectly owned beneficially by such stockholder and any other direct or indirect opportunity to profit or share in any profit derived from any increase or decrease in the value of Abraxas shares, (c) any proxy, contract, arrangement, understanding, or relationship pursuant to which such stockholder has a right to vote any shares of any Abraxas security, (d) any short interest in any Abraxas security (for purposes of this Section 13, a person shall be deemed to have a short interest in a security if such person, directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise, has the opportunity to profit or share in any profit derived from any decrease in the value of the subject security), (e) any rights to dividends on the Abraxas shares owned beneficially by such stockholder that are separated or separable from the underlying Abraxas shares, (f) any proportionate interest in Abraxas shares or Derivative Instruments held, directly or indirectly, by a general or limited partnership in which such stockholder is a general partner or, directly or indirectly, beneficially owns an interest in a general partner and (g) any performance-related fees (other than an asset-based fee) that such stockholder is entitled to based on any increase or decrease in the value of Abraxas shares or Derivative Instruments, if any, as of the date of such notice including, without limitation, any such interests held by members of such stockholder's immediate family sharing the same household (which information shall be supplemented by such stockholder and beneficial owner, if any, not later than 10 days after the record date for the meeting to disclose such ownership as of the record date), and (iii) any other information relating to such stockholder and beneficial owner, if any, that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for, as applicable, the proposal and/or for the election of directors in a contested election pursuant to Section 14 of the Exchange Act, and the rules and regulations promulgated thereunder.

If the notice relates to any business other than a nomination of a director or directors that the stockholder proposes to bring before the meeting, the notice must set forth (i) a brief description of the business desired to be brought before the meeting, the reasons for conducting such business at the meeting and any material interest of such stockholder and beneficial owner, if any, in such business and (ii) a description of all agreements, arrangements and understandings between such stockholder and beneficial owner, if any, and any other person or persons (including their names) in connection with the proposal of such business by such stockholder.

As to each person, if any, whom the stockholder proposes to nominate for election or reelection to the Board of Directors (i) all information relating to such person that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of directors in a contested election pursuant to Section 14 of the Exchange Act and the rules and regulations promulgated thereunder (including such person's written consent to being named in the proxy statement as a nominee and to serving as a director if elected) and (ii) a description of all direct and indirect compensation and other material monetary agreements, arrangements and understandings during the past three years, and any other material relationships, between or among such stockholder and beneficial owner, if any, and their respective affiliates and associates, or others acting in concert therewith, on the one hand, and each proposed nominee, and his or her respective affiliates and associates, or others acting in concert therewith, on the other hand, including, without limitation all information that would be required to be disclosed pursuant to Rule 404 promulgated under Regulation S-K (or any successor rule) if the stockholder making the nomination and any beneficial owner on whose behalf the nomination is made, if any, or any affiliate or associate thereof or person acting in concert therewith, were the "registrant" for purposes of such rule and the nominee were a director or executive officer of such registrant and with respect to each nominee for election or reelection to the Board of Directors, include a completed, dated and signed questionnaire, representation and agreement.

To be eligible to be a nominee for election or reelection as a director of Abraxas, a person must deliver (in accordance with the time periods prescribed above for delivery of notice) to the Secretary at the principal executive offices of Abraxas a written questionnaire with respect to the background and qualification of such person and the background of any other person or entity on whose behalf the nomination is being made (which questionnaire shall be provided by the Secretary upon written request) and a written representation and agreement (in the form provided by the Secretary upon written request) that such person (i) is not and will not become a party to (a) any agreement, arrangement or understanding with, and has not given any commitment or assurance to, any person or entity as to how such person, if elected as a director of Abraxas, will act or vote on any issue or question (a "Voting Commitment") that has not been disclosed to Abraxas or (b) any Voting Commitment that could limit or interfere with such person's ability to comply, if elected as a director of Abraxas, with such person's fiduciary duties under applicable law, (ii) is not and will not become a party to any agreement, arrangement or understanding with any person or entity other than Abraxas with respect to any direct or indirect compensation, reimbursement or indemnification in connection with service or action as a director that has not been disclosed therein, and (iii) in such person's individual capacity and on behalf of any person or entity on whose behalf the nomination is being made, would be in compliance, if elected as a director of Abraxas, and will comply with all applicable publicly disclosed corporate governance, conflict of interest, confidentiality and stock ownership and trading policies and guidelines of Abraxas. Abraxas may also require any proposed nominee to furnish such other information as may reasonably be required by Abraxas to determine the eligibility of such proposed nominee to serve as an independent director of Abraxas or that could be material to a reasonable stockholder's understanding of the independence, or lack thereof, of such nominee.

In the event that the 2012 Annual Meeting is more than 30 days from May 5, 2012 (the anniversary of the 2011 Annual Meeting), the dates for submission with the proxy materials and to be properly brought before the 2012 Annual Meeting will change according to Abraxas' Amended and Restated Bylaws and Regulation 14A under the Exchange Act. A copy of Abraxas' Amended and Restated Bylaws setting forth the advance notice provisions and requirements for submission of stockholder nominations and proposals may be obtained from the Abraxas Secretary at the address indicated on the first page of this proxy statement.

OTHER MATTERS

No business other than the matters set forth in this proxy statement is expected to come before the meeting, but should any other matters requiring a stockholder's vote arise, including a question of adjourning the meeting, the persons named in the accompanying proxy will vote thereon according to their best judgment in the interests of Abraxas. If a nominee for office of director should withdraw or otherwise become unavailable for reasons not presently known, the persons named as proxies may vote for another person in his place in what they consider the best interests of Abraxas.

Upon the written request of any person whose proxy is solicited hereunder, Abraxas will furnish without charge to such person a copy of its annual report filed with the United States Securities and Exchange Commission on Form 10-K, including financial statements and schedules thereto, for the fiscal year ended December 31, 2010. Such written request is to be directed to Investor Relations, 18803 Meisner Drive, San Antonio, Texas 78258.

By Order of the Board of Directors

Stephen T. Wendel
SECRETARY

San Antonio, Texas
April 1, 2011

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2010

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

Commission File Number 001-16071

ABRAXAS PETROLEUM CORPORATION

(Exact name of Registrant as specified in its charter)

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

18803 Meisner Drive
San Antonio, TX 78258
(Address of principal executive offices)

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes ☒ No ☐

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

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

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

As of June 30, 2010, 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 $191,912,033 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 11, 2011, there were 91,561,792 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2011 Annual Meeting of Stockholders to be held on May 5, 2011.	Part III

Form 10-K

ABRAXAS PETROLEUM CORPORATION
FORM 10-K
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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,” “may,” “goal,” “plan,” “seek,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this 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;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- the prices we receive for our oil and gas and the effectiveness of our hedging activities;
- 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 document.

GLOSSARY OF TERMS

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

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

Terms used to describe quantities of oil and gas:

"***Bbl***" – barrel or barrels.

"***Bcf***" – billion cubic feet of gas.

"***Bcfe***" – billion cubic feet of gas equivalent.

"***Boe***" – barrels of oil equivalent.

"***Boepd***" **–** barrels of oil equivalent per day.

"***Bopd***" **–** barrels of oil per day.

"***MBbl***" – thousand barrels.

"***MBoe***" **–** thousand barrels of oil equivalent.

"***Mcf***" – thousand cubic feet of gas.

"***Mcfe***" – thousand cubic feet of gas equivalent.

"***MMBbls***" – million barrels.

"***MMBoe***" – million barrels of oil equivalent.

"***MMbtu***" – million British Thermal Units of gas.

"***MMcf***" – million cubic feet of gas.

"***MMcfe***" – million cubic feet of gas equivalent.

"***MMcfepd***" – million cubic feet of gas equivalent per day.

"***MMcfpd***" – million cubic feet of gas per day.

Terms used to describe our interests in wells and acreage:

"***Developed acreage***" means acreage which consists of leased acres spaced or assignable to productive wells.

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

"***Dry hole***" is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

"***Exploratory well***" is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be producing oil or gas in another reservoir, or to extend a known reservoir.

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

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

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

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

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

"***Proved reserves***" or "***reserves***" are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

"***Proved developed reserves***" or "***PDP's***" 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 oil and gas 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.

"***Proved developed non-producing reserves***" or ***"PDNP's"*** 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 drilling location***" is a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"***Proved undeveloped reserves***" or "***PUD's***" 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 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 in accordance with guidelines promulgated by the SEC.

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

Part I

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 Corporation, together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires. 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. We currently own an approximate 50% 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, 2010, our estimated net proved reserves were 26.6 MMBoe, (including our 50% equity interest in the proved reserves of Blue Eagle), of which 51% were classified as proved developed, 42% were oil and 83% were operated. Our daily net production for the year ended December 31, 2010 was 3,896 Boepd, of which 36% 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, 2010:

	Gross Producing Wells	Average Working Interest	Total Net Acres	Estimated Net Proved Reserves (MBOE)	Net Production (MBOE)
Rocky Mountain	896	11.64%	81,990	8,443.4	385.4
Mid-Continent	147	22.68%	5,769	1,508.4	203.1
Permian Basin	210	74.43%	38,951	5,552.8	464.1
Onshore Gulf Coast(1)	53	87.89%	7,776	10,924.6	368.6
Total United States	1,306	26.13%	134,486	26,429.2	1,421.2
Alberta, Canada	1	100.00%	9,120	141.4	0.9
Total	1,307	26.13%	143,606	26,570.6	1,422.1

(1) Includes 2,622.8 MBOE of estimated proved reserves attributable to our 50% 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, Bakken and Three Forks formations. Well depths range from 7,000 feet down to 12,000 feet. We have 896 gross (104 net) producing wells in the Rocky Mountain region.

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. We have 147 gross (33 net) producing wells in the Mid-Continent region.

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 6,000 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet. We have 210 gross (156 net) producing wells in the Permian Basin region.

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 13,500 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. We have 53 gross (47 net) producing wells in the onshore Gulf Coast region.

Our properties in the province of Alberta, Canada are located in the Pekisko fairway and the Nordegg/Tomahawk area of Central Alberta. Our one gross / net well produces oil and associated gas from the Pekisko formation at a depth of approximately 5,400 feet.

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 on both our unconventional and conventional oil and gas assets, 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 unconventional and conventional plays. We plan to focus our development efforts in 2011 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 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 2011 drilling activity in the oil and liquids-rich resource plays, we expect to increase the oil/liquids component of both our production and proved reserves. Our goal for 2011 is a 50/50 mix of oil/liquids and gas production, as compared to our 36/64 mix of oil/liquids and gas production for the year ended December 31, 2010. Our proved reserves at December 31, 2010 were 41% oil/liquids and 59% gas.

Maintaining financial flexibility. As a result of our recently completed public offering of shares of our common stock, we have approximately $60.0 million available under our credit facility. We anticipate that our primary sources of capital will be availability under our credit facility and cash flow from operations. We plan on deploying our available capital in a cost-effective manner by developing our assets in areas where drilling and service costs are relatively lower and equipment and crews more readily available. For example, because service costs have recently escalated dramatically in the Williston Basin due to a shortage of equipment and crews, we intend to focus our drilling activities in other areas during the first half of 2011 until equipment and crews become more readily available.

2011 Budget and Drilling Activities

We have expanded our capital expenditure budget for 2011 to $60 million, an increase of approximately 66% over 2010. Approximately 50% of the expanded 2011 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region of the United States and the other 50% will target conventional oil plays in the Permian Basin and onshore Gulf Coast regions of the United States and in the province of Alberta, Canada. The 2011 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.

We have a substantial inventory of undeveloped acreage in several unconventional and conventional basins, or plays, exposing us to significant resource potential which will be the focus of our development plans in 2011. 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 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	8,333[1]
Powder River	Niobrara	18,700
Western Alberta	Pekisko	9,120
Southern Alberta	Bakken	10,000
Texas Oil Plays	Strawn / Frio / Yates	8,700
	Total	75,688

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

In 2011, we intend to concentrate our drilling activities in the following unconventional and conventional resource plays:

Williston Basin—Bakken/Three Forks. We currently own 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. We estimate that we have approximately 86 gross (16 net) 1,280-acre units. In 2010, we drilled two operated wells and participated in an additional 10 gross (0.35 net) non-operated wells on the North Dakota side of the basin. Our first operated well, the Ravin 26-35 1H was drilled in McKenzie County, North Dakota and was brought on-line at a restricted rate in November 2010. In January 2011, the well was flow tested at an unrestricted production rate of 1,705 Boepd, comprised of 1,008 barrels of oil, 2.44 MMcf of wellhead gas and 290 barrels of natural gas liquids. Our second operated well is tentatively scheduled to be completed in the second quarter of 2011. In 2011, we plan to drill up to five operated horizontal long lateral wells and participate in several 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. We contributed 8,333 net acres, located in Atascosa, DeWitt and Lavaca Counties, Texas, and received an approximate 50% equity interest in Blue Eagle, and Rock Oil contributed $25 million in cash and received an approximate 50% equity interest. Rock Oil also committed to contribute an additional $50 million in cash. Upon full funding by Rock Oil, we will own a 25% equity interest and Rock Oil will own a 75% equity interest in Blue Eagle.

In 2010, Blue Eagle drilled one well and completed the well in January 2011. The well was completed with a 15-stage fracture stimulation and placed on-line in January 2011 at a restricted rate. During the first 19 days of producing through a 12/64-inch choke, the well produced an average of 5.8 MMcf of liquids-rich gas and 342 barrels of condensate per day. We anticipate that Blue Eagle will drill or participate in four additional wells in 2011, all of which will be fully funded by Blue Eagle. Based on 160-acre spacing, we estimate that there are 52 net drilling locations across the Blue Eagle acreage.

Powder River Basin—Niobrara. We currently own a total of approximately 20,800 gross (18,700 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 2010, 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 Campbell County, Wyoming which are held by production and are near the Crossbow 3-19H well operated by EOG Resources, Inc. in southern Campbell County, Wyoming and other recent horizontal activity. In 2011, we have budgeted the drilling of one horizontal well targeting the Niobrara formation in the Brooks Draw field; however, we may elect to increase our activity in the area pending results of this well. Based on 160–acre spacing and assuming all of the acreage is productive, we estimate that there are 117 net drilling locations on our held by production leasehold.

Alberta Basin—Pekisko. We currently own 9,120 net acres in Central Alberta. In 2010, we drilled two wells in the Twining area as part of a farm-out agreement. One of the wells, the Twining 9-11, came on-line in the first quarter of 2011 and produced an average of 108 Boepd (73% oil) during the first 18 days of production. The other well, the Swalwell 6-6, will be re-completed in the summer of 2011. Our budget for 2011 currently includes the drilling of four horizontal wells targeting the Pekisko formation.

Alberta Basin—Bakken. In the emerging southern Alberta Basin Bakken play of Toole and Glacier Counties, Montana, we currently own approximately 10,000 gross/net acres under long-term leases or direct mineral ownership. During 2010, 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 2011, we intend to continue to acquire additional acreage in the geologically specific parts of the play.

Texas Oil Plays

Permian Basin—Spires Ranch—Strawn. We currently own approximately 5,600 gross/net acres in Nolan County, Texas. In 2009 and 2010, we drilled three wells in the Spires Ranch offsetting the prolific Nena Lucia field. The first well encountered a thick oil column but was pressure depleted. The second and third wells were oil discoveries in the Strawn formation and were completed in the first quarter of 2011. The horizontal well, the Spires 126-1H, came on-line in the first quarter of 2011 and produced an average of 272 Boepd (59% oil) during the first 12 days of production. The vertical well, the Spires 149-1, continues to recover load water. Our budget for 2011 currently includes the drilling of three horizontal wells targeting the Strawn formation.

Permian Basin—Shallow Howe—Yates. We currently own approximately 2,000 gross/net acres in the Howe field, located in Ward County, Texas. In 2010, we evaluated a shallow oil play targeting the Yates formation which has proven to be productive in the area. Our budget for 2011 currently includes the drilling of three vertical wells targeting the Yates formation.

Onshore Gulf Coast Basin—Portilla—Frio. We currently own approximately 1,100 gross/net acres in the Portilla field, located in San Patricio County, Texas. In 2009 and 2010, we drilled three oil in-fill development wells which proved up our concept of undrained pockets of oil between the producing wells. Our budget for 2011 currently includes the drilling of thirteen vertical wells targeting the Frio formation.

Non-Core Divestitures

In the fourth quarter of 2009 and throughout 2010, we sold certain properties, principally non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. We sold properties 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. In total, these properties produced approximately 611 Boepd during 2009 and had 2.3 MMBoe of proved reserves as of December 31, 2009. The first $10.0 million of net proceeds was used to repay the term loan portion of our credit facility and the remaining $22.2 million was used to repay outstanding indebtedness under the revolving portion of the credit facility, for capital expenditures and general corporate purposes.

Sale of Common Stock

On February 1, 2011, we completed 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 $62.0 million, after estimated fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

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 Derivative Activities" and Note 15 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, 2010, two purchasers accounted for approximately 20% of our oil and gas sales, and a single purchaser accounted for 11% 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:

- 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 exploitation 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, which we refer to as BLM, 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 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 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 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 liabilities for pollution resulting from our operations.

Environmental permits that the operators of properties are required to possess may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on our operations as well as the oil and gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

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

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

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as CERCLA, and comparable state statutes impose strict, joint, and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and companies that generated, disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment.

In the course of our ordinary operations, certain wastes may be generated that may fall within CERCLA's definition of a "hazardous substance." We may be liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. Although CERCLA currently contains a "petroleum exclusion" from the definition of "hazardous substance," state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including oil cleanups.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA (as defined below), and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators; to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

Oil Pollution Act of 1990. Federal regulations also require certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The Federal Oil Pollution Act, which we refer to as OPA, contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on our financial position or results of operations.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and gas exploration and production wastes to be classified and regulated as non-hazardous wastes. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and gas exploration and production wastes from regulation as hazardous wastes. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us to incur increased operating expenses. Also, in the ordinary course of our operations, we generate small amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

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

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

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

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment.

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

Hydraulic Fracturing. Many of our operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand, 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 have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, the bills introduced in Congress would require the public disclosure of information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Climate change legislation and greenhouse gas regulation. Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response to these studies, many nations have agreed to limit emissions of “greenhouse gases” or “GHGs” pursuant to the United Nations Framework Convention on Climate Change, and the “Kyoto Protocol.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered “greenhouse gases” regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA*, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, 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. The emissions will be published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has proposed two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and natural gas exploration and production industry and the pipeline industry. The EPA’s finding, the greenhouse gas reporting rule, and the proposed rules to regulate the emissions of greenhouse gases would result in federal regulation of carbon dioxide emissions and other greenhouse gases, require permitting of certain stationary sources, and may 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 when Congress may act on climate change legislation, although initiatives such as the U.S. House of Representatives' adoption of the "American Clean Energy and Security Act of 2009 ("ACESA"), also referred to as the Waxman-Markey cap-and-trade legislation, appears to be unlikely to become law in its current form. The purpose of ACESA was to control and reduce emissions of greenhouse gases in the United States. ACESA would have established an economy-wide cap on emissions of GHGs in the United States and would have required an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. The net effect of ACESA would have been to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and gas. The U.S. Senate has worked on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. 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. However, the discovery of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

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

Title to Properties

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

Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations in the immediate future, we cannot assure you that such materials and resources will be available to us.

Employees

As of March 11, 2011, we had 74 full-time employees. We retain independent geological, land and engineering consultants from time to time on a limited basis and expect to continue to do so in the future.

Available Information

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

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments filed with the Securities and Exchange Commission are available free of charge on our web site at www.abraxaspetroleum.com in the Investor Relations section as soon as practicable after such reports are filed. Information on our 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, 2010, we had a total of $136.0 million of indebtedness under our credit facility which was reduced to $80.0 million, after applying the net proceeds from the equity offering that closed on February 1, 2011. Our indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in our credit facility and future debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we may need a substantial portion of our cash flow from operations to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our level of debt will make us more vulnerable to competitive pressures or a downturn in our business or the economy 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 acquisitions and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness or seeking additional debt or equity capital or bankruptcy protection. We may not be able to 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.

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 decreases 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 our 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 production lost from properties sold with production from the remaining properties, our cash flow from operations will likely decrease, which in turn, would decrease the amount of cash available for additional capital spending.

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

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced. Unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, we cannot assure you that our exploration and development activities will result in increases in our proved reserves. Based on the reserve information set forth in our reserve report as of December 31, 2010, our average annual estimated decline rate for our net proved developed producing reserves is 12% 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 49% of our total estimated proved reserves at December 31, 2010 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;

- 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. For example, service equipment and crews are in very short supply in the Williston Basin. This shortage has caused service costs to escalate drastically in the basin. As a result, we will likely delay the drilling of our operated Bakken/ Three Forks wells until additional services and crews are deployed to the basin and service costs return to normal, which we anticipate to occur in mid-2011.

We may not find any commercially productive oil and gas reservoirs.

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our capital investment. Drilling for oil and gas may be unprofitable. Dry holes and wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. The inherent risk of not finding commercially productive reservoirs is compounded by the fact that 49% of our total estimated proved reserves as of December 31, 2010 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 have recently begun drilling 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 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 the 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;
- 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 and in Canada, drilling and other oil and gas activities cannot be conducted as effectively during the winter 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.

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 plan to 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 intend to insure against all risks. Our oil and gas exploitation and production activities will be 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 and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- 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 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 production method used to extract reserves located in many of the unconventional oil and gas plays in the United States and Canada. 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. Individually or collectively, such 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 that are acceptable or favorable to us.

The marketability of our production depends largely upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities.

The marketability of our production depends in part upon processing and transportation facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by U.S. Federal and state, 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, 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 2010, differentials averaged ($8.14) per Bbl of oil and ($0.41) per Mcf of gas. Approximately 27% of our production during 2010 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 wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

Our derivative contracts could result in financial losses or could reduce our cash flow.

To achieve more predictable cash flow and reduce our exposure to adverse fluctuations in the prices of oil and gas and to comply with the requirements under our credit facility, we enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 80% of the oil and gas production from our estimated net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% 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 not have any basis differential hedging arrangements in place. Our cash flow from operations could also be affected based upon the levels of our production. If production is higher than we estimate, we will have greater commodity price exposure than we intended. If production is lower than the nominal amount that is subject to our hedging arrangements, we may be forced to satisfy all or a portion of our hedging arrangements without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows.

If the prices at which we hedge our oil and gas production are less than current market prices, our cash flow from operations could be adversely affected.

When our derivative contract prices are higher than market prices, we will incur realized and unrealized gains on our derivative contracts and conversely, when our contract prices are lower than market prices, we will incur realized and unrealized losses. On July 29, 2009, we entered into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013 after unwinding our previous hedging arrangements. For the year ended December 31, 2010, we recognized a realized gain on oil and gas derivative contracts of $2.8 million and an unrealized gain of $11.4 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.

We have entered into commodity derivative contracts in order to hedge a portion of our production. 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 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, 2009, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. At December 31, 2008, the net capitalized costs of our oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million, resulting in a write down of $116.4 million. We cannot assure you that we will not experience additional write downs in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2010, we had, subject to the limitation discussed below, $141.8 million of net operating loss carryforwards for U.S. tax purposes and $1.1 million for Canadian tax purposes. The U.S. loss carryforwards will expire in varying amounts through 2030, and the Canadian carryforward will expire in 2030, 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 $60.8 million for deferred tax assets at December 31, 2008, $91.5 million at December 31, 2009 and $91.9 million at December 31, 2010.

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.

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. Gas prices have affected us more than oil prices because 64% of our production during 2010 and 58% of our proved reserves at December 31, 2010 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 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.

The estimates of our reserves as of December 31, 2010 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, 2010. The average realized sales prices as of such date used for purposes of such estimates were $3.91 per Mcf of gas and $70.72 per Bbl of oil. The December 31, 2010 estimates also assume that we will make future capital expenditures of approximately $164.1 million in the aggregate primarily from 2011 through 2015, which are necessary to develop and realize the value of proved reserves on our properties. In addition, approximately 49% of our total estimated proved reserves as of December 31, 2010 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of our reserves set forth or incorporated by reference in this document.

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

As required by SEC regulations, we based the estimated discounted future net cash flows from our proved reserves as of December 31, 2010 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2010 and costs in effect on December 31, 2010, the day of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

- supply of and demand for 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.

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

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

Our oil and gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, ruptures and discharges of toxic gases. In addition, title problems, weather conditions and mechanical difficulties or shortages or delays in delivery of drilling rigs and other equipment could negatively affect our operations. If any of these or other similar industry operating risks occur, we could have substantial losses. Substantial losses also may result from injury or loss of life, severe damage to or destruction of property, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We operate in a highly competitive industry which may adversely affect our operations.

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of 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.

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 distributions.

Shares eligible for future sale may depress our stock price.

At December 31, 2010, we had 76,427,561 shares of common stock outstanding of which 6,089,883 shares were held by affiliates and, in addition, 4,820,450 shares of common stock were subject to outstanding options granted under stock option plans (of which 2,288,213 shares were vested at December 31, 2010).

All of the shares of common stock held by affiliates are restricted or are 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;
- 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, 2010. There are no material lease expirations in 2011.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage[1]		Total
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Net Acres[2]
Rocky Mountain	61,238	31,309	72,358	49,521	1,400	1,160	81,990
Mid-Continent	23,840	5,580	240	120	543	69	5,769
Permian Basin	24,054	17,322	17,977	16,357	12,007	5,272	38,951
Onshore Gulf Coast	5,801	5,173	2,951	2,603	—	—	7,776
Total United States	114,933	59,384	93,526	68,601	13,950	6,501	134,486
Alberta, Canada	320	320	8,800	8,800	—	—	9,120
Total	115,253	59,704	102,326	77,401	13,950	6,501	143,606

(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 developed and undeveloped gross acres, but 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, 2010:

	Productive Wells			
	Oil		Gas[1]	
	Gross	Net	Gross	Net
Rocky Mountain	391.0	88.2	505.0	16.0
Mid-Continent	6.0	3.5	141.0	29.8
Permian Basin	154.0	128.3	56.0	28.1
Onshore Gulf Coast	28.5	26.6	24.5	20.0
Total United States	579.5	246.6	726.5	93.9
Alberta, Canada	1.0	1.0	—	—
Total	580.5	247.6	726.5	93.9

(1) Excludes 1.0 gross (1.0 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, 2010, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for properties comprising approximately 96% of the PV-10 of our proved oil and gas reserves. Proved reserves for the remaining 4% of our properties were estimated by Abraxas personnel because we determined that it was not practical for DeGolyer and MacNaughton to prepare reserve estimates for all of our properties because we own a large number of properties with relatively low values. DeGolyer and MacNaughton's reserve report as of December 31, 2010 included a total of 648 properties, which comprised approximately 96% of the PV-10 of all our properties as of that date. A total of 520 properties were included in the reserve estimates prepared by Abraxas personnel which comprised approximately 4% of our PV-10 at December 31, 2010.

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 22, 2011, 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, 2010 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 25 years of experience in reserve evaluations. The operations department consists of four petroleum engineers with Bachelor degrees in Petroleum Engineering, one of whom is a Registered Professional Engineer in the State of Texas, and various other technical professionals. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages are obtained from other departments within Abraxas.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves were estimated in accordance with guidelines established by the Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. For the year ended December 31, 2010, commodity prices over the prior 12-month period and year end costs were used in estimating 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, 2010, 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 and Gas Reserves
As of December 31, 2010

Reserve Category	Oil (MBbls)	Gas (MMcf)
Proved		
Developed	5,862	42,750
Undeveloped	3,932	42,163
Total Proved	9,794	84,913
Probable		
Developed	183	1,302
Undeveloped	7,145	36,192
Possible		
Developed	—	—
Undeveloped	7,274	14,032

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 set forth or incorporated by reference in this document. 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, 2010 report. The average realized sales prices used for purposes of such estimates were $70.72 per Bbl of oil and $3.91 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $164.1 million in the aggregate primarily in the years 2011 through 2015, 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 Annual Report on Form 10-K 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 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, 2010, the Company's 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 its estimated proved reserves by $4.8 million, resulting in a write down of $4.8 million. We cannot assure you that we will not experience additional write downs in the future. Based on managements' review of average first-day-of-the-month prices for the twelve months of April 2010 through March 2011, we do not anticipate a write down at the end of the first quarter of 2011.

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.

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

Proved Undeveloped Reserves

At December 31, 2010, we had 10,959 MBoe of proved undeveloped reserves. During 2010, 214 MBoe of proved undeveloped reserves were converted to proved producing reserves. During 2010, 2,083 MBoe were added to proved undeveloped reserves, principally in the Rocky Mountain region. During 2010, 1,317 MBoe were removed from proved undeveloped reserves, principally in the onshore Gulf Coast region. We do not have any material proved undeveloped reserves which have remained undeveloped for five or more years since the reserves were included in our reserve report.

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. As a result, there is currently no difference between the standardized measure of our oil and gas reserves, which is a GAAP financial measure, and the PV-10 of our reserves.

Blue Eagle Reserve Data

The following table sets forth certain information attributable to our 50% equity interest in the estimates of Blue Eagle's oil and gas reserves as of December 31, 2010. All of Blue Eagle's reserves are located in the United States.

Summary of Oil and Gas Reserves—Blue Eagle
As of December 31, 2010

Reserve Category	Oil (MBbls)	Gas (MMcf)
Proved		
Developed	—	—
Undeveloped	1,239	8,301
Total Proved	1,239	8,301
Probable		
Developed	—	—
Undeveloped	737	4,933
Possible		
Developed	—	—
Undeveloped	—	—

The following table sets forth certain information regarding the combined reserves of Abraxas and Blue Eagle as of December 31, 2010.

Summary of Oil and Gas Reserves—Combined
As of December 31, 2010

Reserve Category	Oil (MBbls)	Gas (MMcf)
Proved		
Developed	5,862	42,750
Undeveloped	5,171	50,464
Total Proved	11,033	93,214
Probable		
Developed	183	1,302
Undeveloped	7,882	41,125
Possible		
Developed	—	—
Undeveloped	7,274	14,032

Oil and Gas Production, Sales Prices and Production Costs

The following table presents our net oil and gas production, the average sales price per Bbl of oil and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three years ended December 31, 2010:

	2008	2009	2010
Oil production (Bbls)	549,887	578,784	508,917
Gas production (Mcf)	6,342,934	6,329,216	5,478,902
Total production (MBoe)(1)	1,607	1,634	1,422
Average sales price per Bbl of oil(2)	$ 92.66	$ 54.15	$ 71.37
Average sales price per Mcf of gas(2)	$ 7.59	$ 3.24	$ 3.97
Average sales price per Boe(2)	$ 61.66	$ 31.73	$ 40.82
Average cost of production per Boe produced(3)	$ 10.91	$ 12.50	$ 13.81

(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.

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, 2010:

	2008		2009		2010(1)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Oil	—	—	1.0	1.0	1.0	0.02
Gas	1.0	0.6	—	—	1.0	0.40
Dry holes	—	—	—	—	1.0	1.00
Total	1.0	0.6	1.0	1.0	3.0	1.42
Development						
Productive						
Oil	14.0	7.2	2.0	2.0	22.0	7.82
Gas	35.0	2.2	12.0	0.2	2.0	1.02
Dry holes	—	—	1.0	1.0	—	—
Total	49.0	9.4	15.0	3.2	24.0	8.84

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

Present Activities

As of March 11, 2011, we had two operated wells and nine non-operated wells in process of drilling and/or completing. The following provides an overview of our present activities by region:

Operational Update

Rocky Mountain:

- In McKenzie County, North Dakota, we drilled the Stenehjem 27-34 1H to a total measured depth of 16,504 feet, including a 5,965 foot lateral in the middle Bakken formation. A 20-stage fracture stimulation is tentatively scheduled for the second quarter of 2011. We own an approximate 79% working interest in this well.
- In Dunn and McKenzie Counties, North Dakota and Richland County, Montana, we participated in six non-operated horizontal wells, targeting the middle Bakken or Three Forks formation, which are currently drilling, completing or waiting on completion. Our working interest ranges from 1.8% to 6.5% in each of these wells.
- In McKenzie County, North Dakota, we participated in one non-operated horizontal well targeting the Mission Canyon formation, which is currently drilling. We own a 2.9% working interest in this well.
- In Bowman County, North Dakota, we participated in one non-operated horizontal air injection well targeting the Red River formation, which is currently drilling. We own a 4.0% working interest in this well.

Gulf Coast:

- In DeWitt County, Texas, Blue Eagle, is participating in one non-operated horizontal well, targeting the Eagle Ford formation, which is currently drilling. Blue Eagle owns a 43.9% working interest in this well and we currently own an approximate 50% equity interest in Blue Eagle.
- In San Patricio County, Texas, we are currently drilling the first well in a multi-well drilling program targeting the Frio sands at depths of 7,400 and 8,100 feet. We own a 100% working interest in each of these wells.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist of approximately 21,000 square feet. We own the building which is subject to a real estate lien note. The note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2010, $5.1 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.

Other Properties

We own 10 acres of land, an office building, workshop, warehouse and house in Sinton, Texas, 603 acres of land and an office building in Scurry County, Texas, 50 acres of land in Lavaca County, Texas, 160 acres of land in Coke County, Texas, 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.

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, 2010, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

Item 4. [Removed and Reserved]

Part II

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

Market Information

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 on The NASDAQ.

Period	High	Low
2009		
First Quarter	$1.50	$0.74
Second Quarter	1.39	0.85
Third Quarter	1.88	0.86
Fourth Quarter	2.55	1.55
2010		
First Quarter	$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 (Through March 11, 2011)	$6.16	$4.06

Holders

As of March 11, 2011, we had 91,561,792 shares of common stock outstanding and approximately 1,192 stockholders of record.

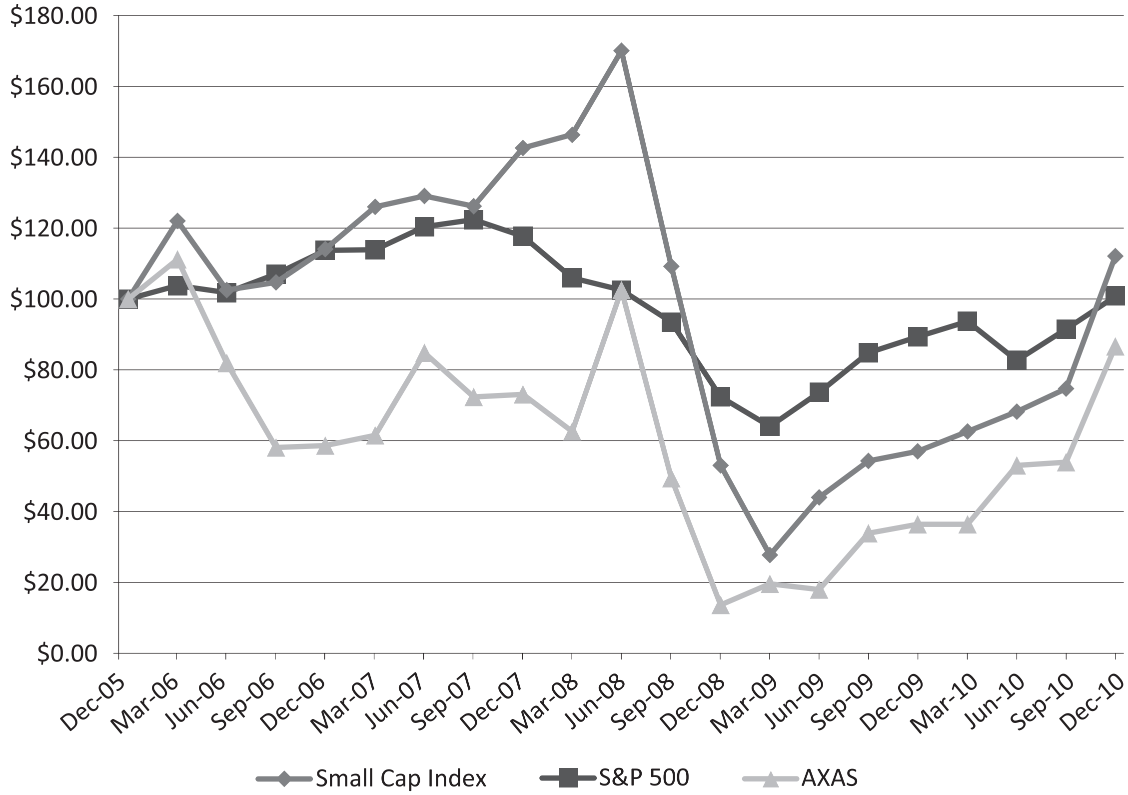
Dividends

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, 2005, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2006, 2007, 2008, 2009 and 2010.



	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2008	Dec. 31, 2009	Dec. 31, 2010
Small Cap Index	$100.00	$114.05	$142.59	$52.93	$56.95	$111.96
S&P 500	$100.00	$113.62	$117.63	$72.36	$89.33	$100.75
AXAS	$100.00	$ 58.52	$ 73.11	$13.64	$36.36	$ 86.55

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

Item 6. Selected Financial Data

The following selected financial data as of and for the years ended is derived from our Consolidated Financial Statements for the years ended December 31, 2006 through 2010. 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,				
	2006	2007	2008	2009	2010
	(Dollars in thousands except per share data)				
Total revenue	$ 51,077	$ 48,309	$100,310	$ 52,750	$ 59,030
Net income (loss)	$ 700	$ 56,702(1)	$ (52,403)(2)	$ (18,780)	$ 1,766(3)
Net income (loss) per common share—diluted	$ 0.02	$ 1.19	$ (1.07)	$ (0.34)	$ 0.02
Weighted average shares outstanding—diluted (in thousands)	43,862	47,593	49,005	55,499	77,362
Total assets	$116,940	$147,119	$211,839	$176,236	$182,909
Long-term debt, excluding current maturities	$127,614	$ 45,900	$130,835	$143,592	$140,940
Total stockholders' equity (deficit)	$ (22,165)	$ 55,847	$ 4,658	$ (18,363)	$ (14,976)

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

Recently, the prices of oil and gas have been volatile. During the first half of 2008, prices for oil and gas were sustained at record or near-record levels, however, during the second half of 2008, and first half of 2009, there was a significant drop in prices. Prices began to improve during the second half of 2009. During 2010, the price of oil increased significantly from the levels experienced in 2009. The New York Mercantile (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $79.51 per barrel in 2010 as compared to $61.82 per barrel in 2009. During 2010, the average price of gas increased slightly from an average NYMEX Henry Hub spot price of $3.94 per MMbtu in 2009 to $4.38 per MMbtu in 2010. Prices closed on December 31, 2010 at $91.38 per Bbl of oil and $4.41 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.

During 2010, differentials averaged ($8.14) per barrel of oil and ($0.41) per Mcf of gas compared to ($7.67) per barrel of oil and ($0.70) per Mcf of gas in 2009 and ($7.07) per barrel of oil and ($1.30) per Mcf of gas in 2008. We experienced greater oil differentials during 2010 compared to prior years because of the increased percentage of our production from the Rocky Mountain region which experiences higher differentials than our Permian Basin and Gulf Coast properties. Approximately 27% of our production during 2010 was from our Rocky Mountain 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 wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

Our credit facility required us to enter into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 1, 2010) through December 31, 2012 and 67% 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 2008, we incurred a realized loss of $9.3 million and an unrealized gain of $40.5 million. In 2009, we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 million. In 2010, we incurred a realized gain of $2.8 million and an unrealized gain of $11.4 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative position at December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price**	**Daily Volume (MMbtu)**	**Swap Price**
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

At December 31, 2010, the aggregate fair market value of our oil and gas derivative contracts was a liability of approximately $2.4 million.

Production Volumes. Our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve estimates as of December 31, 2010, our average annual estimated decline rate for net proved developed producing reserves is 12% 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 2010 of $36.2 million. We have expanded our capital expenditure budget for 2011 to $60 million, an increase of approximately 66% over 2010. Approximately 50% of the expanded 2011 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region of the United States and the other 50% will target conventional oil plays in the Permian Basin and onshore Gulf Coast regions of the United States and in the province of Alberta, Canada. The 2011 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, 2008, 2009 and 2010:

	Year Ended December 31,		
	2008	2009	2010
Total production (MBoe)	1,607	1,634	1,422
Average daily production (Boepd)	4,391	4,476	3,896

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, 2010, we had $4.0 million of availability under our credit facility. In February 2011, we repaid $56.0 million of indebtedness with proceeds from our equity offering, which provided us $60.0 million of availability.

Borrowings and Interest. At December 31, 2010, we had a total of $136.0 million outstanding under our credit facility. In February 2011, we repaid $56.0 million of indebtedness with proceeds from our equity offering, giving us an outstanding balance of $80 million. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our 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.

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, 2010, we operated properties accounting for approximately 88% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations (of which 154 were classified as proved undeveloped at December 31, 2010) 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, 2010, we drilled or participated in 103 gross (30.29 net) wells of which 96.1% resulted in commercially productive wells.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. In addition, approximately 49% of our estimated proved reserves at December 31, 2010 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, (dollars in thousands, except per unit data)		
	2008	2009	2010
Operating revenue[1]:			
Oil sales	$ 50,954	$ 31,340	$ 36,321
Gas sales	48,130	20,489	21,729
Rig and other	1,226	921	980
Total operating revenues	$100,310	$ 52,750	$ 59,030
Operating income (loss)[2]	$ (74,017)	$ 177	$ 2,807
Oil production (MBbls)	549.9	578.8	508.9
Gas production (MMcf)	6,342.9	6,329.2	5,478.9
Average oil sales price (per Bbl)[1]	$ 92.66	$ 54.15	$ 71.37
Average gas sales price (per Mcf)[1]	$ 7.59	$ 3.24	$ 3.97

(1) Revenue and average sales prices are before the impact of hedging activities.
(2) Operating loss includes a $116.4 million and a $4.8 million proved property impairment in 2008 and 2010, respectively.

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

Operating Revenue. During the year ended December 31, 2010, operating revenue from oil and gas sales increased by $6.3 million from $51.8 million in 2009 to $58.1 million in 2010. The increase in revenue was due to higher oil and gas prices in 2010 as compared to 2009 which were partially offset by decreased production 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.

Oil sales volumes decreased from 578.8 MBbls for the year ended December 31, 2009 to 508.9 MBbls for the same period of 2010. 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 from 6,329.2 MMcf for the year ended December 31 2009 to 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 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.

Average sales prices in 2010, before realized gain (loss) on derivative contracts were:

- $71.37 per Bbl of oil, and
- $ 3.97 per Mcf of gas.

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

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

Lease Operating Expenses ("LOE"). LOE decreased from $20.4 million in 2009 to $19.6 million in 2010. LOE per Boe for the year ended December 31, 2010 was $13.81 compared to $12.50 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 increased from $5.8 million in 2009 to $5.9 million in 2010 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 from $6.5 million in 2009 to $7.3 million in 2010. 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 from $17.9 million in 2009 to $16.2 million in 2010. 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 2009 was $10.95 as compared to $11.40 per Boe in 2010.

Interest Expense. Interest expense decreased to $9.1 million in 2010 compared to $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 year ended December 31, 2010, we realized a gain on our derivative contracts of $500,000, 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 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. Based on managements' review of average first-day-of-the-month prices for the twelve months of April 2010 through March 2011, we do not anticipate a write down at the end of the first quarter of 2011.

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 (gain) loss of joint venture. Our investment in Blue Eagle, in which we do not have a majority interest, but do have significant influence, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from the joint venture is reflected as an increase (decrease) in our investment account and is also recorded as equity investment income (loss). Our net share of the joint ventures earnings or losses is reported as "Equity in (gain) loss of joint venture" in the consolidated statements of operations. For year ended December 31, 2010, our net share of the joint venture's loss was $473,000.

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

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

Oil production volumes increased from 549.9 MBbls for the year ended December 31, 2008 to 578.8 MBbls for the same period of 2009, primarily due to production from new wells placed on production during 2009. Gas production volumes decreased from 6,342.9 MMcf for the year ended December 31, 2008 to 6,329.2 MMcf for the same period of 2009, primarily due to natural field declines.

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

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

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

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

Lease Operating Expenses ("LOE"). LOE increased from $17.5 million in 2008 to $20.4 million in 2009 as a result of higher operating costs. LOE per Boe for the year ended December 31, 2009 was $12.50 compared to $10.91 for the same period of 2008. The increase in LOE per Boe was attributable to higher operating costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes decreased from $9.1 million in 2008 to $5.8 million in 2009 as a result of lower commodity prices which result in lower production taxes.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased from $5.7 million in 2008 to $6.5 million in 2009. The increase in G&A in 2009 as compared to 2008 was primarily due to higher professional and consulting fees, as well as increased cost for director fees related to the Merger and the opening of our Canadian office in September 2009. G&A per Boe was $3.96 for 2009 compared to $3.56 for the same period of 2008. The increase in G&A per Boe cost was attributable to the higher G&A during 2009 as compared to 2008.

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

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense decreased from $23.3 million in 2008 to $17.9 million in 2009. The decrease in DD&A was primarily the result of the producing property impairment for the year ended December 31, 2008 which reduced our full cost pool. DD&A per Boe for 2009 was $10.95 as compared to $14.53 in 2008. The decrease in DD&A per Boe in 2009 was primarily the result of the book value of our full cost pool being reduced due to the impairment incurred in 2008.

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

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. No income tax expense or benefit was recognized in 2008 due to losses or loss carryforwards and valuation allowance, which has been recorded against such benefits.

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 $16.3 million as of December 31, 2009. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2009, we realized a gain on our derivative contracts of $15.3 million, which included a realized gain of $17.9 million on our commodity swaps and a realized loss of $2.6 million on our interest rate swap. For the year-ended December 31, 2009, we incurred an unrealized loss of $27.6 million, which included an unrealized loss of $28.4 million on our commodity swaps and an unrealized gain of $0.8 million on our interest rate swap. For the year ended December 31, 2008, we realized a loss on our derivative contracts of $9.5 million, which included a realized loss of $9.3 million on our commodity swaps and a realized loss of $260,000 on our interest rate swap. For the year ended December 31, 2008, we incurred an unrealized gain of $37.9 million, which included an unrealized gain of $40.5 million on our commodity swaps and an unrealized loss of $2.6 million on our interest rate swap.

Other Expense. For the year ended December 31, 2008, as a result of the exchange and registration rights agreement whereby Partnership unitholders, under certain circumstances, could convert their Partnership units into Abraxas common stock, we recognized an expense of $7.4 million, including approximately $293,000 relating to shares converted during the fourth quarter of 2008 and $7.1 million representing the fair value of potential conversions. During 2009, other expense consisted primarily of costs related to the planned initial public offering of the Partnership which had previously been capitalized.

Ceiling Limitation Write-down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2008, our net capitalized costs of our United States oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million, resulting in a write down of $116.4 million. These amounts were calculated in accordance with previous SEC rules utilizing 2008 year-end prices of $44.60 per Bbl for oil and $5.62 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves. As 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, 2008 and 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. Additionally, in accordance with generally accepted accounting principles in effect at the time, when cumulative losses applicable to the non-controlling interest exceeded the non-controlling interest equity capital in the entity, such excess are charged to the earnings of the controlling interest. For the year ended December 31, 2008, primarily as a result of the ceiling test impairment, losses applicable to the non-controlling interest exceeded the controlling interest equity capital by $9.3 million. As a result, $9.3 million was charged to earnings attributable to Abraxas and reflected as a reduction of the loss applicable to the non-controlling interest.

Liquidity and Capital Resources

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

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

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to 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, 2010, our current liabilities of $37.5 million exceeded our current assets of $28.6 million resulting in a working capital deficit of $8.9 million. This compares to a working capital deficit of $17.4 million at December 31, 2009. Current liabilities at December 31, 2010 primarily consisted of the current portion of derivative liabilities of $9.7 million, trade payables of $23.6 million, revenues due third parties of $3.0 million, and other accrued liabilities of $1.1 million.

Capital Expenditures. Capital expenditures in 2008, 2009 and 2010 were $174.6 million, $16.5 million and $36.4 million, respectively. The table below sets forth the components of these capital expenditures:

	Year Ended December 31,		
	2008	2009	2010
	(dollars in thousands)		
Expenditure category:			
Exploration/Development	$ 40,564	$16,151	$36,172
Acquisition	127,671	—	—
Facilities and other	6,351	320	276
Total	$174,586	$16,471	$36,448

During 2008, capital expenditures included $127.7 million for the acquisition of properties from St. Mary Land & Exploration Company and other smaller acquisitions, as well as the development of our oil and gas properties. During 2009 and 2010, capital expenditures were primarily for the development of our existing properties.

We anticipate making capital expenditures in 2011 of $60.0 million. The 2011 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 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. There was a significant decline in oil and gas prices beginning in the second quarter of 2008, while oil prices improved during the second half of 2009 and through 2010, gas prices remain fairly weak. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital 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.

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,		
	2008	2009	2010
	(dollars in thousands)		
Net cash provided by operating activities	$ 43,387	$ 44,136	$ 24,102
Net cash used in investing activities	(173,944)	(14,096)	(15,048)
Net cash provided by (used in) financing activities	113,545	(30,103)	(10,816)
Total	$ (17,012)	$ (63)	$ (1,762)

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.

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

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.

In the fourth quarter of 2009 and throughout 2010, we sold certain non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. We sold properties 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. In total, these properties produced approximately 611 Boepd during 2009 and had 2.3 MMBoe of proved reserves as of December 31, 2009. The first $10.0 million of net proceeds was used to repay the term loan portion of our credit facility and the remaining $22.2 million was used to repay outstanding indebtedness under the revolving portion of the credit facility, for capital expenditures and general corporate purposes.

On February 1, 2011, we completed 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 $62.0 million, after estimated fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile and declined significantly during the second half of 2008 and first part of 2009. Oil prices increased during the second six months of 2009 and during 2010, and while gas prices have strengthened somewhat, they remain 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 49% of our total estimated proved reserves at December 31, 2010 were classified as undeveloped.

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, 2010:

	Payments due in twelve month periods ending:				
Contractual Obligations (in thousands)	**Total**	**December 31, 2011**	**December 31, 2012-2013**	**December 31, 2014-2015**	**Thereafter**
Long-Term Debt[(1)]	$141,092	$ 152	$136,336	$4,604	$ —
Interest on long-term debt[(2)]	15,128	8,144	6,591	393	—
Lease obligations[(3)]	142	46	92	4	—
Total	$156,362	$8,342	$143,019	$5,001	$ —

(1) These amounts represent the balances outstanding under our credit facility and the real estate lien note. These payments assume that we will not borrow additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.
(3) Lease on office space in Calgary, Alberta, which expires on January 31, 2014.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2010, our reserve for these obligations totaled $7.7 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, 2010, 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, 2010, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

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

Long-Term Indebtedness

Long-term debt consisted of the following:

	December 31, 2009	December 31, 2010
	(in thousands)	
Credit facility—Term portion	$ 8,000	$ —
Credit facility—Revolving portion	138,500	136,000
Real estate lien note	5,233	5,092
	151,733	141,092
Less current maturities	(8,141)	(152)
	$143,592	$140,940

Credit Facility

On October 5, 2009, in connection with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility, which was amended on August 18, 2010. In connection with the Merger, we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion. The term portion of the credit facility was paid in full on March 30, 2010. As of December 31, 2010, $136.0 million was outstanding under the revolving portion of the credit facility. This outstanding amount was reduced to $80.0 million after applying the net proceeds from the equity offering that closed on February 1, 2011.

The revolving portion of the credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $140.0 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 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 lenders are also able to make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $140.0 million was determined based upon our reserve report dated June 30, 2010. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the revolving portion of the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2010, the interest rate on the revolving portion of the credit facility was 5.75%.

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

Each of our subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of our and our subsidiary guarantors' material property and assets.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 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 or at the request of a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718 , ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts or upon the termination of any hedge contract minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements. We were in compliance with all covenants as of December 31, 2010.

As of December 31, 2010, the current ratio was 1.01 to 1.00, the interest coverage ratio was 3.16 to 1.00 and the total debt to EBITDAX ratio was 3.96 to 1.00.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

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.

Real Estate Lien Note

On May 9, 2008, we 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 our corporate headquarters. This note was refinanced in November 2008. The note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2010, $5.1 million was outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. Under the terms of our credit facility, we entered into commodity swaps on approximately 80% of our estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013.

The following table sets forth our derivative contract position as of December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**	**Daily Volume (MMbtu)**	**Swap Price (per MMbtu)**
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

By removing a significant portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future will sustain, realized and unrealized losses on our derivative contracts 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, 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.

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

Net Operating Loss Carryforwards

At December 31, 2010, we had, subject to the limitation discussed below, $141.8 million of net operating loss carryforwards for U.S. tax purposes and $1.1 million for Canadian tax purposes. The U.S. loss carryforwards will expire through 2030 and the Canadian carryforward will expire in 2030, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10. Therefore, we have established a valuation allowance of $91.9 million for deferred tax assets at December 31, 2010.

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, 2010. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2010, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2000 through 2010 remain open to examination by the tax jurisdictions to which the Company is subject.

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.

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

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

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years, most recently in 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 U.S. generally accepted accounting principles ("GAAP") and SEC guidelines. The accuracy of a reserve estimate is a function of:

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

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

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on costs on the date of the estimate and for the years ended December 31, 2009 and 2010, oil and gas prices were based on the average 12-month first-day-of-the-month pricing as compared to end of period prices in prior years. Actual future prices and costs may be materially higher or lower than the prices and costs 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. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. Due to the volatility of oil and gas prices and, to a lesser extent, interest rates, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2009 and 2010, the net market value of our commodity derivatives was a net liability of $14.0 million and $2.5 million, respectively. The market value of our interest rate derivative was a liability of $2.2 million and $3.3 million at December 31, 2009 and 2010, 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 8 to the consolidated financial statements. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date and expense is recognized over the vesting period. For the years ended December 31, 2008, 2009 and 2010, stock-based compensation was approximately $1.4 million, $1.2 million, and $1.6 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 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 January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2010-6, "*Improving Disclosures about Fair Value Measurements*" ("ASU No. 2010-06"). ASU No. 2010-06 amends FASB Accounting Standards Codification ("ASC") Topic 820, "*Fair Value Measurements and Disclosures,*" to require additional information to be disclosed principally regarding Level 3 measurements and transfers to and from Level 1 and 2. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 measurements. This guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). The update will not have a material impact on the Company's consolidated results of operations or financial position.

In February 2010, the FASB issued Accounting Standards Update No. 2010-09, "*Amendments to Certain Recognition and Disclosure Requirements*" ("ASU No. 2010-09"). ASU No. 2010-09 amends FASB ASC Topic 855-10, "*Subsequent Events,*" to remove the requirement for an SEC filer to disclose the date through which subsequent events have been evaluated in both issued and revised financial statements. This change alleviates potential conflicts between ASC 855-10 and the SEC's requirements. The update did not have a material impact on the Company's consolidated results of operations or financial position.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will 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 indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2010, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flow by approximately $5.8 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. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contract are recognized in earnings during the current period.

The following table sets forth our derivative contract position as of December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The two-year interest rate swap 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, 2010, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $2.5 million and the aggregate fair market value of our interest rate swap was a liability of approximately $3.3 million.

For the year ended December 31, 2010, we recognized a realized gain of $2.8 million and an unrealized gain of $11.4 million on our commodity derivative contracts and we recognized a realized loss of $2.3 million and an unrealized loss of $1.1 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, 2010, we had $136.0 million of outstanding indebtedness under our credit facility. This outstanding amount was reduced to $80.0 million after applying the proceeds of our equity offering that closed on February 1, 2011. 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) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2010, the interest rate on the revolving portion of the credit facility was 5.75%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.4 million on an annual basis, based on our outstanding indebtedness as of December 31, 2010. 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, 2010 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, 2010.

The effectiveness of our internal control over financial reporting as of December 31, 2010 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, 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers and Corporate Governance

There is incorporated in this Item 10 by reference to that portion of our definitive proxy statement for the 2011 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 Craig S. 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 Craig S. 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 Securities and Exchange Commission and The NASDAQ initial reports of ownership and reports of changes in ownership of Abraxas common stock. Officers, directors and greater than 10% stockholders are required by SEC regulations to furnish us with copies of all such forms they file. Based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required. We believe that all our directors and executive officers complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act during 2010.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2011 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 2011 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 2011 Annual Meeting of Stockholders which appears therein under the captions "Certain Transactions" and "Election of Directors – Director Independence."

Item 14. Principal Accountants Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2011 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services."

PART IV

Item 15. Exhibits and Financial Statements

(a) 1. Consolidated Financial Statements

(a) 2. Financial Statement Schedules

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

(a) 3. Exhibits

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

Exhibit Number	Description
3.1	Articles of Incorporation of Abraxas. (Filed as Exhibit 3.1 to our Registration Statement on Form S-4, No. 33-36565 (the "S-4 Registration Statement")).
3.2	Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement).
3.3	Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement).
3.4	Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to our Registration Statement on Form S-3, No. 333-00398).
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	Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to Abraxas' Current Report on Form 8-K filed on November 17, 2008).
3.7	Certificate of Designation of Series 2010 Junior Participating Preferred Stock (Filed as Exhibit 3.1 to Abraxas 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 Abraxas 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 Abraxas' Registration Statement on Form S-4, No. 333-18673).
*10.2	Abraxas Petroleum Corporation Amended and Restated 1994 Long Term Incentive Plan. (Filed as Exhibit 10.4 to Abraxas' Registration Statement on Form S-4 filed on January 12, 2005).
*10.3	Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.4 to our Annual Report on Form 10-K filed on March 14, 2007).

Exhibit Number	Description
*10.4	Employment Agreement between Abraxas and Robert L.G. Watson. (Filed as Exhibit 10.19 to the Registration Statement on Form S-1, No. 333-95281 (the "2000 S-1 Registration Statement")).
*10.5	Employment Agreement between Abraxas and Chris E. Williford. (Filed as Exhibit 10.20 to the 2000 S-1 Registration Statement).
*10.6	Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the Registration Statement on Form S-3, No. 333-127480 (the "S-3 Registration Statement")).
*10.7	Employment Agreement between Abraxas and William H. Wallace. (Filed as Exhibit 10.27 to the S-3 Registration Statement).
*10.8	Employment Agreement between Abraxas and Lee T. Billingsley. (Filed as Exhibit 10.28 to the S-3 Registration Statement).
*10.9	Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on June 6, 2005).
*10.10	Form of Stock Option Agreement under the Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed on June 6, 2005).
*10.11	Abraxas Petroleum Corporation Senior Management Incentive Bonus Plan 2006. (Filed as Exhibit 10.17 to Abraxas' Annual Report on Form 10-K filed on March 23, 2006).
*10.12	Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (Filed as Annex E to Abraxas' Proxy Statement filed on September 8, 2009).
*10.13	Form of Employee Stock Option Agreement under the Abraxas 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed on August 26, 2006).
10.14	Limited Liability Company Agreement of Blue Eagle Energy, LLC dated August 18, 2010. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on August 23, 2010).
10.15	Form of Common Stock Purchase Warrant. (Filed as Exhibit 10.8 to Abraxas' Current Report on Form 8-K filed on May 31, 2007).
10.16	Voting, Registration Rights and Lock-Up Agreement, dated as of June 30, 2009, by and among Abraxas Petroleum, Abraxas Energy and certain limited partners of Abraxas Energy (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on July 2, 2009).
10.17	Form of Indemnification Agreement by and among Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, and each of its officers and directors. (Filed as Exhibit 10.25 to Abraxas' Annual Report on Form 10-K filed on March 17, 2008).
10.18	Amended and Restated Credit Agreement dated as of October 5, 2009 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on October 7, 2009).
14.1	Abraxas Petroleum Corporation Code of Business Conduct and Ethics. (Filed as Exhibit 14.1 to Abraxas' Annual Report on Form 10-K filed on March 22, 2006).
18.1	Change in Accounting Principles. (Filed as Exhibit 18.1 to Abraxas' Annual Report on Form 10-K/A Number 2 filed on August 20, 2008).
21.1	Subsidiaries of Abraxas. (Filed as Exhibit 21.1 to Abraxas' Annual Report on Form 10-K filed on March 17, 2010).
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).
31.2	Certification—Chief Financial Officer. (Filed herewith).
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).
32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).
99.1	Report of DeGolyer and MacNaughton. (filed herewith).

* Management Compensatory Plan or Agreement.

SIGNATURES

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

ABRAXAS PETROLEUM CORPORATION

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

DATED: March 16, 2011

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 16, 2011
/s/ Chris E. Williford Chris E. Williford	Exec. Vice President and Treasurer (Principal Financial and Accounting Officer)	March 16, 2011
/s/ Craig S. Bartlett, Jr. Craig S. Bartlett, Jr.	Director	March 16, 2011
/s/ Franklin A. Burke Franklin A. Burke	Director	March 16, 2011
/s/ Harold D. Carter Harold D. Carter	Director	March 16, 2011
/s/ Ralph F. Cox Ralph F. Cox	Director	March 16, 2011
/s/ Dennis E. Logue Dennis E. Logue	Director	March 16, 2011
/s/ Paul A. Powell, Jr. Paul A. Powell, Jr.	Director	March 16, 2011
/s/ Brian L. Melton Brian L. Melton	Director	March 16, 2011
/s/ Edward P. Russell Edward P. Russell	Director	March 16, 2011

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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

Form 10-K

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, 2009 and 2010 and the related consolidated statements of operations, stockholders' equity (deficit), cash flows, and other comprehensive income (loss) for each of the three years in the period ended December 31, 2010. 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, 2009 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 16, 2011 expressed an unqualified opinion thereon.

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

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

/s/ BDO USA, LLP

Dallas, Texas
March 16, 2011

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, 2010, 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, 2010, 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, 2009 and 2010, and the related consolidated statements of operations, stockholders' equity (deficit), cash flows, and other comprehensive income (loss) for each of the three years in the period ended December 31, 2010 and our report dated March 16, 2011 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Dallas, Texas
March 16, 2011

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2009	December 31, 2010
	(Dollars in thousands)	
Current assets:		
Cash and cash equivalents	$ 1,861	$ 99
Accounts receivable:		
Joint owners	865	5,145
Oil and gas production sales	7,873	6,958
Other	31	642
	8,769	12,745
Derivative asset—current	325	6,941
Assets held for sale	—	8,457
Other current assets	514	396
Total current assets	11,469	28,638
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	454,142	434,858
Unproved properties excluded from depletion	—	1,085
Other property and equipment	11,259	11,536
Total	465,401	447,479
Less accumulated depreciation, depletion, and amortization	309,245	330,231
Total property and equipment—net	156,156	117,248
Investment in joint venture	—	24,027
Deferred financing fees, net	5,804	3,494
Derivative asset—long-term	2,253	8,674
Other assets including marketable securities	554	828
Total assets	$176,236	$182,909

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' DEFICIT

	December 31, 2009	December 31, 2010
	(Dollars in thousands)	
Current liabilities:		
Accounts payable	$ 8,773	$ 23,589
Joint interest oil and gas production payable	3,606	3,000
Accrued interest	563	277
Other accrued expenses	770	779
Derivative liability—current	7,047	9,742
Current maturities of long-term debt	8,141	152
Total current liabilities	28,900	37,539
Long-term debt—less current maturities	143,592	140,940
Derivative liability—long-term	11,781	11,672
Future site restoration	10,326	7,734
Total liabilities	194,599	197,885
Commitments and contingencies		
Stockholders' 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; 76,231,751 and 76,427,561, issued and outstanding	762	764
Additional paid-in capital	182,647	184,223
Accumulated deficit	(201,974)	(200,208)
Accumulated other comprehensive income	202	245
Total stockholders' deficit	(18,363)	(14,976)
Total liabilities and stockholders' deficit	$ 176,236	$ 182,909

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2008	2009	2010
	(In thousands except per share data)		
Revenues:			
Oil and gas production revenues	$ 99,084	$ 51,829	$ 58,050
Rig revenues	1,210	914	970
Other	16	7	10
	100,310	52,750	59,030
Operating costs and expenses:			
Lease operating	17,536	20,421	19,642
Production taxes	9,099	5,803	5,910
Depreciation, depletion, and amortization	23,343	17,886	16,212
Impairment	116,366	—	4,787
Rig operations	856	758	803
General and administrative (including stock-based compensation of $1,404, $1,239 and $1,560, respectively)	7,127	7,705	8,869
	174,327	52,573	56,223
Operating income (loss)	(74,017)	177	2,807
Other (income) expense:			
Interest income	(187)	(15)	(8)
Amortization of deferred financing fees	1,028	1,326	2,479
Interest expense	10,496	11,346	9,106
Financing fees	359	362	—
Loss (gain) on derivative contracts (unrealized $(37,860), $27,650 and $(10,285), respectively)	(28,333)	12,322	(10,811)
Equity in loss of joint venture	—	—	473
Other	8,523	2,071	(119)
	(8,114)	27,412	1,120
Income (loss) from operations before income tax and non-controlling interest	(65,903)	(27,235)	1,687
Income tax benefit (expense)	—	(1,290)	79
Consolidated net income (loss)	(65,903)	(28,525)	1,766
Less: Net loss attributable to non-controlling interest	13,500	9,745	—
Net income (loss) attributable to Abraxas Petroleum	$ (52,403)	$(18,780)	$ 1,766
Net income (loss) attributable to Abraxas Petroleum common stockholders—per common share—basic	$ (1.07)	$ (0.34)	$ 0.02
Net income (loss) attributable to Abraxas Petroleum common stockholders—per common share—diluted	$ (1.07)	$ (0.34)	$ 0.02

See accompanying notes to consolidated financial statements

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, 2007	49,020,949	$490	$185,646	$(130,791)	$ 502	$ 23,497	$ 79,344
Net Loss	—	—	—	(52,403)	—	(13,500)	(65,903)
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	(389)	—	(389)
Stock-based compensation	—	—	1,162	—	—	—	1,162
Shares issued for compensation	30,655	—	60	—	—	—	60
Stock options exercised	141,501	2	65	—	—	—	67
Warrants exercised	31,961	—	—	—	—	—	—
Conversion of units in Partnership	344,752	3	290	—	—	—	293
Restricted stock issued, net of cancellations	52,605	1	20	—	—	—	21
Partnership distributions	—	—	—	—	—	(9,997)	(9,997)
Abraxas shares issuable under exchange rights agreement	—	—	—	—	—	7,093	7,093
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)

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2008	2009	2010
		(In thousands)	
Operating Activities			
Net income (loss)	$ (65,903)	$(28,525)	$ 1,766
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Equity in loss of joint venture	—	—	473
Change in derivative fair value	(42,304)	25,740	(10,451)
Monetization of derivative contracts	—	26,736	—
Depreciation, depletion, and amortization	23,343	17,886	16,212
Impairment	116,366	—	4,787
Accretion of future site restoration	570	558	516
Amortization of deferred financing fees	1,028	1,326	2,479
Stock-based compensation	1,404	1,239	1,560
Registration fees previously capitalized	—	2,210	—
Loss on disposal of assets	—	289	—
Other non-cash transactions	7,446	78	24
Changes in operating assets and liabilities:			
Accounts receivable	(1,838)	(803)	(3,976)
Other assets and liabilities	(206)	(7)	(113)
Accounts payable	4,082	(1,545)	14,210
Accrued expenses	(601)	(1,046)	(3,385)
Net cash provided by operating activities	43,387	44,136	24,102
Investing Activities			
Capital expenditures, including purchases and development of properties	(174,586)	(16,471)	(36,448)
Proceeds from the sale of oil and gas properties	642	2,375	21,400
Net cash used in investing activities	(173,944)	(14,096)	(15,048)
Financing Activities			
Proceeds from exercise of stock options and warrants	88	203	69
Transaction costs on exchange of partnership units	—	(2,557)	—
Proceeds from long-term borrowings	135,084	13,500	3,000
Payments on long-term borrowings	(10,015)	(32,736)	(13,641)
Partnership distribution to non-controlling interest	(9,997)	(2,257)	—
Deferred financing fees	(1,615)	(5,687)	(169)
Other	—	(569)	(75)
Net cash provided by (used in) financing activities	113,545	(30,103)	(10,816)
Decrease in cash	(17,012)	(63)	(1,762)
Cash at beginning of year	18,936	1,924	1,861
Cash at end of year	$ 1,924	$ 1,861	$ 99
Supplemental disclosures of cash flow information:			
Interest paid	$ 9,817	$ 10,575	$ 8,876
Non-Cash Investing Activities:			
Asset retirement obligation cost and liabilities	$ —	$ (80)	$ (83)
Asset retirement obligations associated with property acquisitions and dispositions	$ 8,206	$ 2	$ (2,735)
Properties contributed to joint venture	$ —	$ —	$ 24,500

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2008	2009	2010
	(In thousands)		
Net income (loss)	$(52,403)	$(18,780)	$1,766
Other comprehensive income (loss):			
Change in unrealized value of investments	(389)	95	(27)
Foreign currency translation adjustment	—	(6)	70
Other comprehensive income (loss)	(389)	89	43
Comprehensive income (loss)	$(52,792)	$(18,691)	$1,809

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

On June 30, 2009, Abraxas Petroleum and the Partnership signed an Agreement and Plan of Merger, which we refer to as the Original Merger Agreement, pursuant to which the Partnership agreed to merge with and into Abraxas Petroleum with Abraxas Petroleum surviving and on July 17, 2009, Abraxas Petroleum and the Partnership signed an Amended and Restated Agreement and Plan of Merger, which we refer to as the Merger Agreement, pursuant to which the Partnership agreed to merge with and into Abraxas Merger Sub, LLC, which we refer to as Merger Sub, with Merger Sub surviving the merger as a wholly-owned subsidiary of Abraxas Petroleum. We refer to this merger as the Merger. Under the terms of the Merger Agreement, at the effective time of the Merger on October 5, 2009, 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 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.

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

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and the operations of the Partnership which was formed on May 25, 2007. The interest of the 51.8% owners of the Partnership was presented as non-controlling interest (through the date of its merger into Abraxas Petroleum). Abraxas owned the remaining 48.2% of Partnership interests. The Company determined that based on its control of the general partner of the Partnership, this 48.2% owned entity should be consolidated for financial reporting purposes.

Liquidity

The recent global recession had a significant impact on our operations. As a result of the recession, gas prices were depressed due to the weak demand in the manufacturing industry and the oversupply of natural gas thereby causing a prolonged downturn, which reduced our future cash flows from operations. In the future, if gas prices continue to be weak or if a significant decline in oil prices occurs, , it could reduce our future cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Management believes that it is reasonably possible that estimates of future proved oil and gas revenues could significantly change in the future.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and 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 $33,000 and $54,000 at December 31, 2009 and 2010, 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. For the year ended December 31, 2008, the Company incurred an impairment of $116.4 million, based on year end prices of $44.60 per barrel of oil and $5.62 per Mcf of gas. As of December 31, 2009, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. 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. We did not own any properties outside of the United States in 2008 or 2009.

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 5, "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 February 1, 2011.

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with U.S. generally accepted accounting principles ("GAAP") and SEC guidelines. The accuracy of a reserve estimate is a function of:

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

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

In accordance with SEC requirements, beginning December 31, 2009, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the average 12 month first-day-of-month pricing for the years ended December 31, 2009 and 2010, and costs as of December 31, 2009 and 2010. Prior to December 31, 2009, such estimates had been based on year end prices and costs. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact 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.

The adoption of the new guidance as of December 31, 2009 resulted in a downward adjustment of $139.9 million to the estimated discounted future cash flows from proved reserves and a reduction of 1,973.8 MBoe of proved reserves for the year ended December 31, 2009. Additionally, the change resulted in an increase of $335,000 in DD&A expense in the fourth quarter of 2009.

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are 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 derivate 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 on derivative contracts in the current period.

Fair Value of Financial Instruments

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

Share-Based Payments

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the vesting period. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2008, 2009 and 2010, stock-based compensation was approximately $1.4 million, $1.2 million and $1.6 million, respectively. For additional information regarding share-based payments, please see Note 8, "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:

	2008	2009	2010
		(in thousands)	
Beginning asset retirement obligation	$1,183	$ 9,959	$10,326
New wells placed on production and other	9,046	91	64
Deletions related to property disposals and plugging costs	(840)	(282)	(3,172)
Accretion expense	570	558	516
Ending asset retirement obligation	$9,959	$10,326	$ 7,734

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, 2008, 2009 and 2010.

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

During 2008, 2009 and 2010, two purchasers accounted for 14% and 15%; 11% and 11%; and 11% and 10% of oil and gas revenues, respectively.

Deferred Financing Fees

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

Income Taxes

The Company records deferred income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10. Therefore, we have established a valuation allowance of $91.9 million for deferred tax assets at December 31, 2010.

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 market value of available-for-sale investments and foreign currency translation adjustments.

Accounting for Uncertainty in Income Taxes

ASC 740 provides guidance on accounting for uncertainty in income taxes. ASC 740 is intended to clarify the accounting for uncertainty in income taxes recognized in a company's financial statements and prescribes the recognition and measurement of a tax position taken or expected to be taken in a tax return. ASC 740 also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Under ASC 740, evaluation of a tax position is a two-step process. The first step is to determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation based on the technical merits of that position. The second step is to measure a tax position that meets the more-likely-than-not threshold to determine the amount of benefit to be recognized in the financial statements. A tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

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

New Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2010-6, "*Improving Disclosures about Fair Value Measurements*" ("ASU No. 2010-06"). ASU No. 2010-06 amends FASB Accounting Standards Codification ("ASC") Topic 820, "*Fair Value Measurements and Disclosures,*" to require additional information to be disclosed principally regarding Level 3 measurements and transfers to and from Level 1 and 2. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 measurements. This guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). The update did not have a material impact on the Company's consolidated results of operations or financial position.

In February 2010, the FASB issued Accounting Standards Update No. 2010-09, "*Amendments to Certain Recognition and Disclosure Requirements*" ("ASU No. 2010-09"). ASU No. 2010-09 amends FASB ASC Topic 855-10, "*Subsequent Events,*" to remove the requirement for an SEC filer to disclose the date through which subsequent events have been evaluated in both issued and revised financial statements. This change alleviates potential conflicts between ASC 855-10 and the SEC's requirements. The update did not have a material impact on the Company's consolidated results of operations or financial position.

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.

Simultaneous with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility and we refinanced and amended and restated the partnership credit facility, the Partnership's subordinated credit agreement and Abraxas' previous credit facility and we borrowed approximately $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion. See Note 6 Long-Term Debt.

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 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 million in cash to Blue Eagle for a $25 million equity interest in Blue Eagle. Rock Oil committed to contribute an additional $50 million to Blue Eagle and upon full funding, Abraxas Petroleum will own a 25% equity interest in Blue Eagle and Rock Oil will own a 75% equity interest in Blue Eagle.

Blue Eagle's subject area encompasses 12 counties across the Eagle Ford Shale play for expected future acreage acquisitions. Abraxas Petroleum will operate the wells owned by Blue Eagle and Rock Oil will manage the day-to-day business affairs of Blue Eagle. Robert L. G. Watson, our President and CEO, will serve on the Board of Managers of Blue Eagle.

At formation and as of December 31, 2010, we owned a non-controlling 50.0% interest in the joint venture. We account for the joint venture under the equity method of accounting. Under the equity method of accounting, 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 an equity investment income (loss) in "*Equity in earnings (loss) of joint venture.*" For the year ended December 31, 2010, we incurred a loss of $473,000.

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

Balance Sheet:

	As of December 31, 2010
	(in thousands)
Assets:	
Current assets	$19,625
Oil and gas properties	31,753
Other assets	45
Total assets	$51,423
Liabilities and Capital:	
Current liabilities	$ 3,368
Member capital	48,055
Total liabilities and capital	$51,423

Statement of Operations:

	For the period August 18, 2010 (inception) through December 31, 2010
	(in thousands)
Revenue	$—
Operating expenses	682
Other expense	263
Net loss	$(945)

4. Acquisitions

On January 31, 2008, Abraxas Operating, LLC, a then wholly-owned subsidiary of the Partnership, consummated the acquisition of certain oil and gas properties located in various states from St. Mary Land & Exploration Company ("St. Mary") and certain other sellers for a purchase price of approximately $126.0 million. The properties are primarily located in the Rocky Mountain and Mid-Continent regions of the United States.

Simultaneously, Abraxas Petroleum completed the acquisition of certain oil and gas properties from St. Mary for a purchase price of approximately $5.6 million. The right to purchase these properties had been assigned to Abraxas by the Partnership.

Substantially all amounts paid in the acquisition, including acquisition costs of approximately $1.1 million, were allocated to the oil and gas properties.

The following unaudited supplemental information presents pro forma financial results assuming the acquisition had occurred on January 1, 2008. The unaudited pro forma financial results are not necessarily those that would have been attained had the acquisition occurred as of an earlier date, nor are they necessarily representative of the future results that may occur.

	Year Ended December 31, 2008
	(in thousands)
Revenue	$104,262
Net income (loss)	$ (50,281)
Earnings (loss) per share—basic	$ (1.02)

5. Divestiture of Non-Core Properties

In the fourth quarter of 2009 and throughout 2010, we sold certain properties, principally non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. We sold properties 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. In total, these properties produced approximately 611 Boepd during 2009 and had approximately 2.3 MMBoe of proved reserves at December 31, 2009. The first $10.0 million of net proceeds was used to repay the term loan portion of our credit facility and the remaining $22.2 million was used to repay outstanding indebtedness under the revolving portion of the credit facility, for capital expenditures and general corporate purposes.

6. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2009 and 2010, respectively:

	December 31, 2009	December 31, 2010
	(in thousands)	
Senior secured credit facility—Term portion	$ 8,000	$ —
Senior secured credit facility—Revolving portion	138,500	136,000
Real estate lien note	5,233	5,092
	151,733	141,092
Less current maturities	(8,141)	(152)
	$143,592	$140,940

Maturities of long-term debt are as follows:

Year ended December 31, (in thousands)	
2011	$ 152
2012	136,163
2013	173
2014	185
2015	4,419
Thereafter	—
	$141,092

Credit Facility

On October 5, 2009, in connection with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility, which was amended on August 18, 2010. In connection with the Merger, we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion. The term portion of the credit facility was paid in full on March 30, 2010. As of December 31, 2010, $136.0 million was outstanding under the revolving portion of the credit facility. This outstanding amount was reduced to $80.0 million after applying the net proceeds from the equity offering that closed on February 1, 2011.

The revolving portion of the credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $140.0 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 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 lenders are also able to make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $140.0 million was determined based upon our reserve report dated June 30, 2010. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the revolving portion of the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2010, the interest rate on the revolving portion of the credit facility was 5.75%.

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

Each of our subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of our and our subsidiary guarantors' material property and assets.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 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 or at the request of a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718 (which relates to stock-based compensation), ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts or upon the termination of any hedge contract minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements. We were in compliance with all covenants as of December 31, 2010.

As of December 31, 2010, the current ratio was 1.01 to 1.00, the interest coverage ratio was 3.16 to 1.00 and the total debt to EBITDAX ratio was 3.96 to 1.00.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

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.

Real Estate Lien Note

On May 9, 2008, the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as its corporate headquarters. This note was refinanced in November 2008. The note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2010, $5.1 million was outstanding on the note.

7. Property and Equipment

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

	Estimated Useful Life	December 31, 2009	December 31, 2010
	Years	(In thousands)	
Oil and gas properties	—	$454,142	$435,943
Equipment and other	3-39	11,259	11,536
		$465,401	$447,479

8. 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. The fair value for these options was estimated at the date of grant using the following weighted average assumptions for 2008, 2009 and 2010:

	2008	2009	2010
Weighted average value per option granted during the period	$ 4.37	$ 1.41	$ 1.61
Assumptions:(1)(2)(3)			
Expected dividend yield	0%	0%	0%
Volatility	52.0%	83.0%	84.03%
Risk free interest rate	4.39%	2.48%	2.87%
Expected life (years)	7.9 years	6.1 years	9.0 years
Fair value of options granted (in thousands)	$ 211	$ 2,195	$ 1,553

(1) The Company's estimated future forfeiture rate is based on the Company's historical forfeiture rate.
(2) Calculated using the Black-Scholes fair value based method.
(3) 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. 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, 2010:

	Options (000s)	Weighted Average Exercise Price	Weighted Average Remaining Life	Intrinsic value Per Share
Options outstanding December 31, 2007	2,526	$2.65		
Granted	86	4.37		
Exercised	(183)	1.37		
Forfeited/Expired	(39)	2.55		
Options outstanding December 31, 2008	2,390	$2.81		
Granted	2,175	1.41		
Exercised	(250)	0.93		
Forfeited/Expired	(225)	2.73		
Options outstanding December 31, 2009	4,090	2.18		
Granted	964	2.12		
Exercised	(213)	.89		
Forfeited/Expired	(21)	2.93		
Options outstanding December 31, 2010	4,820	$2.23	7.16	$2.23
Exercisable at end of year	2,288		5.42	$2.79

Other information pertaining to the Company's stock option activity was as follows during the three years ended December 31, 2010:

	2008	2009	2010
Weighted average grant date fair value of stock options granted (per share)	$ 2.47	$1.01	$2.23
Total fair value of options vested (000's)	$1,022	$ 801	$ 949
Total intrinsic value of options exercised (000's)	$ 149	$ 155	$ 373

As of December 31, 2010, the total compensation cost related to non-vested awards not yet recognized is approximately $2.9 million, which will be recognized in 2011 through 2014. For the year ended December 31, 2010, we recognized $1.2 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, 2010:

	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	1,330,205	6.01	$0.88	654,980	3.75	$0.76
$1.00 – 1.99	1,303,035	8.55	$1.69	397,014	8.04	$1.57
$2.00 – 2.99	1,023,357	8.89	$2.16	146,857	6.95	$2.51
$3.00 – 3.99	285,852	6.69	$3.60	211,361	6.68	$3.60
$4.00 – 4.99	799,001	4.92	$4.57	799,001	4.92	$4.56
$5.00 – 6.05	79,000	5.15	$6.05	79,000	5.15	$6.05
	4,820,450			2,288,213		

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, 2010 we recognized $400,000 in stock-based compensation expense related to restricted stock awards.

The following table is a summary of the Company's restricted stock activity for the three years ended December 31, 2010:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2007	152,348	$3.60
Granted	55,952	2.85
Vested	(41,061)	3.60
Forfeited	(2,959)	3.51
Unvested December 31, 2008	164,280	$3.35
Granted	462,552	1.71
Vested/Released	(74,648)	2.76
Forfeited	(3,276)	2.62
Unvested December 31, 2009	548,908	$2.05
Granted	20,000	2.45
Vested/Released	(155,268)	2.22
Forfeited	(13,345)	1.85
Unvested December 31, 2010	400,295	$2.02

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, 2008 or 2010. In connection with the closing of the Merger, restricted unit awards were converted into restricted stock awards of the Company. See note 2.

Phantom Units

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

For the year ended December 31, 2008 and 2009, the Partnership incurred equity-based compensation expense of $242,000 and $25,000, respectively, relating to phantom units. In connection with the closing of the Merger, outstanding phantom unit awards were converted into restricted stock awards of the Company. See Note 2.

Director Stock Awards

Shares Reserved and Awards. The 2005 Directors Plan (as amended) reserves 1.2 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 10,000 shares of Abraxas common stock, for participation in board and committee meetings during the previous calendar year. The maximum annual award for any one person is 60,000 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise price shall be no less than 100% of the fair market value on the date of the award while the option terms and vesting schedules are at the discretion of the committee. In addition to the 10,000 shares or options 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 2008, 2009, and 2010, there were 30,655, 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. Subsequent to April 2010, directors are compensated for their annual retainer fee of $26,000 in cash.

At December 31, 2010, the Company had approximately 7.3 million shares reserved for future issuance for conversion of its stock options, warrants, and incentive plans for the Company's directors, employees and consultants.

Warrants

On May 25, 2007, Abraxas entered into a Securities Purchase Agreement with certain accredited investors pursuant to which Abraxas issued warrants to purchase 1,174,938 shares of common stock, to the investors at a price of $3.83 per share. The warrants expire on May 25, 2012 and are exercisable at a price of $3.83 per share, subject to certain adjustments. During 2008, 182,768 warrants were exercised. No warrants were exercised in 2009 and 114,230 were exercised in 2010.

9. Income Taxes

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

	December 31,		
	2008	2009	2010
	(In thousands)		
Deferred tax liabilities:			
Marketable securities	$ 33	$ 67	$ 57
Investment in Blue Eagle	—	—	7,107
Partnership interest	18,349	—	—
Total deferred tax liabilities	18,382	67	7,164
Deferred tax assets:			
U.S. full cost pool	418	37,360	37,464
Canada full cost pool	—	—	1,238
Capital loss carryforward	—	—	
Depletion carryforward	5,189	4,421	4,667
U.S. net operating loss carryforward	68,034	42,583	49,621
Canada net operating loss carryforward	—	—	301
Alternative minimum tax credit	78	503	422
Allocated minority loss carryforward	3,267	—	—
Hedge contracts	—	3,798	1,904
Other	2,159	2,890	3,447
Total deferred tax assets	79,145	91,555	99,064
Valuation allowance for deferred tax assets	(60,763)	(91,488)	(91,900)
Net deferred tax assets	18,382	67	7,164
Net deferred tax	$ —	$ —	$ —

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

	Years ended December 31,		
	2008	2009	2010
	(in thousands)		
Current:			
Federal	$—	$425	$—
State	—	865	(79)
Foreign	—	—	—
	$—	$1,290	$(79)
Deferred:			
Federal	$—	$—	$—
Foreign	—	—	—
	$—	—	—

At December 31, 2010, the Company had, subject to the limitation discussed below, $141.8 million of net operating loss carryforwards for U.S. tax purposes, and $1.1 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire from 2022 through 2030, and the Canadian loss carryforward will expire in 2030, 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 and $91.9 million at December 31, 2010.

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

	Years ended December 31,		
	2008	2009	2010
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	$ 18,341	$ 6,121	$ (591)
(Increase) decrease in deferred tax asset valuation allowance	(13,592)	(30,725)	(412)
Expired capital loss carryforward	(4,742)	—	—
Basis difference in hedge liability	—	—	1,890
Rate differential for non U.S. income	—	—	(385)
State income taxes	—	(562)	—
Permanent differences	(6)	(4)	(409)
Increase in asset basis for Merger	—	23,986	—
Other	(1)	(106)	(14)
	$—	$ (1,290)	$ 79

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, 2010. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2010, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2000 through 2010 remain open to examination by the tax jurisdictions to which the Company is subject.

10. Commitments and Contingencies

Operating Leases

For the year ended December 31, 2008, the Company incurred rent expense related to leasing office facilities of approximately $321,000. During 2008, the Company acquired a building for its corporate headquarters; accordingly, there are no future rental payments under such leases. In September 2009, the Company leased office space in Calgary, Alberta. During 2009 and 2010, rent expense of $32,300 CN ($30,400 USD) and $91,528 CN ($88,511 USD) was incurred related to this lease.

Litigation and Contingencies

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2010, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

11. Earnings per Share

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

	Years ended December 31:		
	2008	2009	2010
	(in thousands, except per share data)		
Numerator:			
Net income (loss)	$(52,403)	$(18,780)	$ 1,766
Denominator:			
Denominator for basic earnings per share—weighted-average common shares outstanding	49,005	55,499	75,923
Effect of dilutive securities:			
Stock options, restricted shares and warrants	—	—	1,301
Dilutive potential common shares			
Denominator for diluted earnings per share—adjusted weighted-average shares and assumed exercise of options, restricted shares and warrants	49,005	55,499	77,224
Net income (loss) per common share—basic	$ (1.07)	$ (0.34)	$ 0.02
Net income (loss) per common share—diluted	$ (1.07)	$ (0.34)	$ 0.02

Basic earnings per share excludes any dilutive effects of options, warrants, unvested restricted stock and convertible securities and is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share are computed similar to basic; however, diluted earnings (loss) per share reflects the assumed conversion of all potentially dilutive securities. For the years ended December 31, 2008 and 2009, 334,656 and 310,692 potential shares relating to stock options, respectively, were excluded from the calculation of diluted earnings (loss) per share since their inclusion would have been anti-dilutive due to the loss incurred in the period.

12. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2009 and 2010 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2009				
Net revenue	$10,850	$ 12,368	$13,409	$ 16,123
Operating income (loss)	$ (1,823)	$ 64	$ 557	$ 1,379
Net income (loss)	$ 4,450	$(10,032)	$ (4,370)	$ (8,828)
Net income (loss) per common share—basic	$ 0.09	$ (0.20)	$ (0.09)	$ (0.12)
Net income (loss) per common share—diluted	$ 0.09	$ (0.20)	$ (0.09)	$ (0.12)
Year Ended December 31, 2010				
Net revenue	$16,126	$ 14,909	$13,969	$ 14,026
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)

13. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees of the Company. In 2008, 2009 and 2010, in accordance with the safe harbor provisions of the plan the Company contributed $144,954, $157,436 and $177,817, respectively, to the plan. The employee contribution limitations are determined by formulas, which limit the upper one third of the plan members from contributing amounts that would cause the plan to be top-heavy. The employee contribution limit for 2008, 2009 and 2010 was $15,500, $16,500 and $16,500, respectively, for employees under the age of 50. The employee contribution limit for 2008, 2009 and 2010 was $20,500, $22,000 and $22,000, respectively, for employees 50 years of age or older.

14. 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 2010, two customers accounted for approximately 20% of consolidated oil and natural gas production revenue. Two customers accounted for approximately 20% of United States revenue and one customer accounted for 100% of revenue in Canada.

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

	Year Ended December 31, 2010			
	U.S.	Canada	Corporate	Total
	(in thousands)			
Revenues:				
Oil and gas production	$ 57,990	$ 60	$ —	$ 58,050
Rig revenue	970	—	—	970
Other	—	—	10	10
	58,960	60	10	59,030
Costs and expenses:				
Lease operating	19,627	16	—	19,643
Production taxes	5,909	—	—	5,909
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
Rig operations	803	—	—	803
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

	As of December 31, 2010			
	U.S.	Canada	Corporate	Total
	(in thousands)			
Segment assets	$152,599	$ 4,393	$ 25,917	$182,909

15. 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 contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contract are recognized in earnings during the current period.

The terms of our credit facility required us to enter into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

The following table sets forth our derivative contract position as of December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR-based debt. The two-year interest rate swap 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, 2009		December 31, 2010	
	Balance Sheet Location	Fair Value (thousands)	Balance Sheet Location	Fair Value (thousands)
NYMEX-based fixed price derivative contracts	Derivative asset—current	$ 325	Derivative asset—current	$ 6,941
NYMEX-based fixed price derivative contracts	Derivative asset—long-term	$ 2,253	Derivative asset—long-term	$ 8,674
NYMEX-based fixed price derivative contracts	Derivative liability—current	$ 4,791	Derivative liability—current	$ 6,394
NYMEX-based fixed price derivative contracts	Derivative liability—long-term	$11,781	Derivative liability—long-term	$11,672
Interest rate swap	Derivative liability—current	$ 2,256	Derivative liability—current	$ 3,348

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

16. 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 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 on a Non-Recurring Basis

On January 1, 2009, the Company adopted the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. As it relates to Abraxas, the adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value, impaired oil and gas property assessments, and the initial recognition of asset retirement obligations for which fair value is used.

The adoption of ASC 820-10 did not have material impact on the Company's consolidated financial statements or its disclosures with respect to the initial recognition of asset retirement obligations during the year ended December 31, 2010. These estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Abraxas has designated these liabilities as Level 3.

Fair Value Hierarchy—ASC 820-10 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1—inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2—inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3—inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument.

The following tables presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2009 and 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Assets:				
Investment in common stock	$208	$ —	$ —	$ 208
NYMEX Fixed Price Derivative contracts	—	2,578	—	2,578
Total Assets	$208	$ 2,578	$ —	$ 2,786
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$16,572	$ —	$16,572
Interest Rate Swaps	—	—	2,256	2,256
Total Liabilities	$—	$16,572	$2,256	$18,828

	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

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, 2010 in US dollars. Accordingly this investment is characterized as Level 1.

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

In 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, 1012. As there is no actively traded market for this type of swap and no observable market parameters, these derivative contracts are classified as Level 3.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the three years ended December 31, 2010 is as follows (in thousands):

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

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

The non-controlling interest in the (income) loss of the Partnership represents the third parties 51.8% interest in the Partnership's net income/ loss, through the date of the Merger. In accordance with generally accepted accounting principles in effect prior to the adoption of ASC 810, which codifies SFAS 160, when cumulative losses applicable to the non-controlling interest exceed the non-controlling interest equity capital in the entity, such excess was charged to the earnings of the controlling interest. For the year ended December 31, 2008, primarily as a result of the ceiling test impairment of the Partnership's oil and gas properties, losses applicable to the non-controlling interest exceeded the non-controlling equity capital by $9.3 million. As a result, $9.3 million of the non-controlling interest was charged to earnings attributable to Abraxas and was reflected as a reduction of the loss applicable to the non-controlling interest.

18. Subsequent Events

Sale of Common Stock

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 Abraxas of approximately $62.0 million, after estimated fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

19. 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					
	2009			2010		
	Total	U.S.	Canada	Total	U.S.	Canada
	(in thousands)					
Proved oil and gas properties	$ 454,142	$ 454,142	$—	$ 434,858	$ 427,337	$ 7,521
Unproved properties	—	—	—	1,085	—	1,085
Total	454,142	454,142	—	435,943	427,337	8,606
Accumulated depreciation, depletion, amortization and impairment	(305,354)	(305,354)	—	(325,793)	(320,957)	(4,836)
Net capitalized Costs	$ 148,788	$ 148,788	$—	$ 110,150	$ 106,380	$ 3,770

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

	Years Ended December 31								
	2008			2009			2010		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(in thousands)								
Development costs	$ 38,644	$ 38,644	$—	$15,356	$15,356	$ —	$31,278	$23,757	$7,521
Exploration costs	1,920	1,920	—	795	795	—	3,809	3,809	—
Property acquisition costs:									
Proved	127,671	127,671	—	—	—	—	—	—	—
Unproved	—	—	—	—	—	—	1,085	—	1,085
	$168,235	168,235	$ —	$16,151	$16,151	$ —	$36,172	$27,566	$8,606

The results of operations for oil and gas producing activities for the three years ended December 31, 2008, 2009 and 2010 are as follows:

	Years Ended December 31,								
	2008			2009			2010		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(in thousands)								
Revenues	$ 99,084	$ 99,084	$—	$ 51,829	$ 51,829	$—	$ 58,050	$ 57,990	$ 60
Production costs	(26,635)	(26,635)	—	(26,224)	(26,224)	—	(25,790)	(25,774)	(16)
Depreciation, depletion, and amortization	(23,077)	(23,077)	—	(17,361)	(17,361)	—	(15,653)	(15,603)	(50)
Proved property impairment	(116,366)	(116,366)	—	—	—	—	(4,787)	—	(4,787)
General and administrative	(1,431)	(1,431)	—	(1,617)	(1,617)	—	(2,323)	(1,635)	(688)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ (68,425)	$ (68,425)	$—	$ 6,627	$ 6,627	$—	$ 9,497	$ 14,978	$(5,481)
Depletion rate per barrel of oil equivalent	$ 14.42	$ 14.42	$—	$ 10.63	$ 10.63	$—	$ 11.00	$ 10.98	$ 59.97

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, 2008, 2009, and 2010. 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 commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows as of December 31, 2009 and 2010. However, period end prices and costs were used in estimating reserve volumes and future net cash flows as of December 31, 2008.

	Total		United States		Canada	
	Liquid Hydrocarbons (Barrels)	Gas (Mcf)	Liquid Hydrocarbons (Barrels)	Gas (Mcf)	Liquid Hydrocarbons (Barrels)	Gas (Mcf)
			(in thousands)			
Proved developed and undeveloped reserves:						
Balance at January 1, 2008	3,131	88,003	3,131	88,003	—	—
Revisions of previous estimates	(1,651)	(6,160)	(1,651)	(6,160)	—	—
Extensions and discoveries	458	5,862	458	5,862	—	—
Purchases of minerals in place	5,684	27,110	5,684	27,110	—	—
Sales of minerals in place	(27)	(56)	(27)	(56)	—	—
Production	(550)	(6,343)	(550)	(6,343)	—	—
Balance at December 31, 2008	7,045	108,416	7,045	108,416	—	—
Revisions of previous estimates	193	(14,652)	193	(14,652)	—	—
Extensions and discoveries	2,173	9,090	2,173	9,090	—	—
Production	(579)	(6,329)	(579)	(6,329)	—	—
Balance at December 31, 2009	8,832	96,525	8,832	96,525	—	—
Revisions of previous estimates	1,067	729	1,067	729	—	
Extensions and discoveries	1,329	1,456	1,252	1,066	77	390
Sales of minerals in place	(925)	(8,318)	(925)	(8,318)	—	—
Production	(509)	(5,479)	(508)	(5,479)	(1)	—
Balance at December 31, 2010	9,794	84,913	9,718	84,523	76	390

	Total		United States		Canada	
	Liquid Hydrocarbons (Barrels)	Gas (Mcf)	Liquid Hydrocarbons (Barrels)	Gas (Mcf)	Liquid Hydrocarbons (Barrels)	Gas (Mcf)
			(in thousands)			
Proved Developed Reserves:						
December 31, 2008	5,563	48,209	5,563	48,209	—	—
December 31, 2009	5,891	47,861	5,891	47,861	—	—
December 31, 2010	5,862	42,750	5,786	42,360	76	390
Proved Undeveloped Reserves:						
December 31, 2008	1,482	60,207	1,482	60,207	—	—
December 31, 2009	2,941	48,665	2,941	48,665	—	—
December 31, 2010	3,932	42,163	3,932	42,163	—	—

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

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

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.

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, 2008, 2009 and 2010. The following information has been prepared in accordance with the Securities and Exchange Commission rules and accounting standards based on year end prices and costs for December 31, 2008, and based on the 12-month first-day-of-the-month average prices for December 31, 2009 and 2010 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 average, first-day-of-the-month price beginning with the year ended December 31, 2009. The previous rules required reserve estimates be calculated using last day of the year pricing. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis of the properties. Operating loss carryforwards, tax credits, and permanent differences to the extent estimated to be available in the future were also considered in the future income tax calculations, thereby reducing the expected tax expense to zero. Because prices used in the calculation are average prices for 2010, 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 geological and engineering data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 22, 2011, 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, 2008, 2009 and 2010 were based on studies performed by the operations department of Abraxas. The operations department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Operations is the manager of this department and is the primary technical person responsible for this process. The Vice President of Operations holds a Bachelor of Science degree in Petroleum Engineering, and has 25 years of experience in reserve evaluations. The operations department consists of four petroleum engineers with Bachelor degrees in Petroleum Engineering, one of whom is a Registered Professional Engineer in the State of Texas, and various other technical professionals.

The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted to represent the fair market value of the Company's proved oil and gas reserves. An estimate of fair market value would also take into account, among other factors, the recovery of reserves not classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure. Set forth below is the Standardized Measure relating to our proved oil and gas reserves for the three years ended December 31, 2008, 2009 and 2010:

	Years Ended December 31,								
	2008			2009			2010		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(in thousands)								
Future cash inflows	$ 811,644	$ 811,644	$—	$ 816,436	$ 816,436	$—	$1,020,286	$1,012,829	$ 7,457
Future production costs	(312,756)	(312,756)	—	(332,283)	(332,283)	—	(391,396)	(389,395)	(2,001)
Future development costs	(134,073)	(134,073)	—	(138,354)	(138,354)	—	(164,135)	(163,085)	(1,050)
Future income tax expense	—	—	—	—	—	—	—	—	—
Future net cash flows	364,815	364,815	—	345,799	345,799	—	464,755	460,349	4,406
Discount	(212,823)	(212,823)	—	(195,270)	(195,270)	—	(267,762)	(266,041)	(1,721)
Standardized Measure of discounted future net cash relating to proved reserves	$ 151,992	$ 151,992	$—	$ 150,529	$ 150,529	$—	$ 196,993	$ 194,308	$ 2,685

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,		
	2008	2009	2010
	(in thousands)		
Standardized Measure, beginning of year	$215,686	$151,992	$150,529
Sales and transfers of oil and gas produced, net of production costs	(72,449)	(25,605)	(32,261)
Net change in prices and development and production costs from prior year	(69,094)	(4,883)	70,311
Extensions, discoveries, and improved recovery, less related costs	8,694	22,267	14,508
Purchases of minerals in place	61,761	—	—
Sales of minerals in place	(366)	—	(18,868)
Revisions of previous quantity estimates	(16,222)	(13,578)	9,694
Change in timing and other	2,414	5,137	(11,973)
Accretion of discount	21,568	15,199	15,053
Standardized Measure, end of year	$151,992	$150,529	$196,993

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,		
	2008	2009	2010
Oil (per barrel)(1)	$44.60	$61.18	$79.43
Gas (per MMbtu)(2)	5.62	4.19	4.45
Oil (per barrel)(3)	41.74	55.05	70.72
Gas (per MMbtu)(4)	4.77	3.42	3.91

(1) The quoted oil price for the year ended December 31, 2008 is the NYMEX future price as of December 31, 2008. The quoted oil price for the year ended December 31, 2009 and 2010 is the 12-month average first-day-of-the-month West Texas Intermediate spot price for each month of 2009 and 2010.

(2) The quoted gas price for the year ended December 31, 2008 is the NYMEX future price as of December 31, 2008. The quoted gas price for the year ended December 31, 2009 and 2010 is the 12-month average first-day-of-the-month Henry Hub spot price for each month of 2009 and 2010.

(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.

The following table contains information relating to proved reserves attributable to Abraxas' 50% equity interest in Blue Eagle as of December 31, 2010. All of Blue Eagle's reserves are in the United States.

	Total	
	Liquid Hydrocarbons (Barrels)	Gas (Mcf)
	(in thousands)	
Proved developed and undeveloped reserves:		
Balance at December 31, 2009	—	—
Revisions of previous estimates	—	—
Extensions and discoveries	1,239	8,301
Sales of minerals in place	—	—
Production	—	—
Balance at December 31, 2010	1,239	8,301
Proved Developed	—	—
Proved Undeveloped	1,239	8,301

Form 10-K

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Annual Shareholders Meeting
May 5, 2011 at 10:00 a.m. CT
Petroleum Club
San Antonio, Texas

OFFICERS

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President / Chief Executive Officer

Chris E. Williford
Executive Vice President /
Chief Financial Officer

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

William H. Wallace
Vice President—Operations

Stephen T. Wendel
Vice President—Land and Marketing

Barbara M. Stuckey
Vice President—Corporate Finance

DIRECTORS

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Chairman of the Board / President /
Chief Executive Officer,
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C. Scott Bartlett, Jr.[1]
Executive Vice President (retired),
Bank of America
Richmond Hill, Georgia

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

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

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

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

Brian L. Melton[1]
Vice President—Corporate Strategy,
Inergy, L.P.
Kansas City, Missouri

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

Edward P. Russell
President,
Tortoise Capital Resources Corp.
Leawood, Kansas

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

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