ABRAXAS

2012 Annual Report
Proxy Statement
Form 10-K

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

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

TO BE HELD MAY 14, 2013

To the Stockholders of Abraxas Petroleum Corporation:

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of Abraxas Petroleum Corporation ("Abraxas" or the "Company") will be held at our corporate office located at 18803 Meisner Drive, San Antonio, Texas 78258, on May 14, 2013, at 9:00 a.m., local time, for the following purposes:

(1) To elect as directors to the Abraxas Board of Directors the four nominees named below for a term of three years:
- Harold D. Carter
- Jerry J. Langdon
- Brian L. Melton
- Edward P. Russell

(2) To ratify the appointment of BDO USA, LLP as Abraxas' independent registered public accounting firm for the year ending December 31, 2013;

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

(4) 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.

Your Board recommends that you vote FOR Proposals 1, 2 and 3.

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 in the envelope provided or vote by telephone or over the internet as soon as possible. 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 22, 2013 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. Only stockholders of record at the close of business on March 22, 2013, will be entitled to vote at the Annual Meeting and any adjournments or postponements thereof. A list of stockholders entitled to vote at the Annual Meeting will be available for inspection at our offices, 18803 Meisner Drive, San Antonio, Texas 78258 for 10 days prior to the Annual Meeting. If you would like to review the stockholder list, please call our Investor Relations department at (210) 490-4788 to schedule an appointment.

All stockholders are cordially invited to attend the Annual Meeting. If you have any questions about the attached proxy or require assistance in voting your shares on the proxy card or voting instruction form, or need additional copies of the Company's proxy materials, please contact the firm assisting us in the solicitation of proxies, Morrow & Co., LLC, toll free at (888) 836-9724.

By Order of the Board of Directors,

Stephen T. Wendel
SECRETARY

San Antonio, Texas
April 12, 2013

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of Stockholders to be held May 14, 2013

This proxy statement and our 2012 Annual Report on Form 10-K are available at www.abraxaspetroleum.com, which does not have "cookies" that identify visitors to the site.

If you have any questions or require any assistance with voting your shares, please contact our proxy solicitor at the contact listed below:

MORROW & CO., LLC

470 West Avenue
Stamford, Connecticut 06902
(203) 658-9400 (Call Collect)
or
Call Toll-Free (888) 836-9724

ABRAXAS PETROLEUM CORPORATION

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

PROXY STATEMENT

The Board of Directors of Abraxas Petroleum Corporation ("Abraxas" or the "Company") is soliciting proxies to vote shares of common stock at the 2013 Annual Meeting of Stockholders to be held at 9:00 a.m., local time, on May 14, 2013, at Abraxas Petroleum Corporation located at 18803 Meisner Drive, San Antonio, Texas 78258, and at any adjournment thereof. This proxy statement and the accompanying proxy are first being mailed to stockholders on or about April 12, 2013. 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. If you would like to review the stockholder list, please call our Investor Relations department at (210) 490-4788 to schedule an appointment.

Record Date; Shares Entitled To Vote; Quorum

The Board of Directors has fixed the close of business on March 22, 2013 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 92,733,448 shares of Abraxas common stock outstanding, which were held by approximately 1,148 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.

A "broker non-vote" occurs when you fail to provide your broker with voting instructions and the 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. A broker non-vote may also occur if your broker fails to vote your shares for any reason. Brokers cannot vote on their customers' behalf on "non-routine" proposals such as Proposal 1, the election of directors, and Proposal 3, the advisory vote on executive compensation. Because brokers require their customers' direction to vote on such non-routine matters, it is critical that stockholders provide their brokers with voting instructions. Proposal 2, ratification of the appointment of our independent registered public accounting firm, will be a "routine" matter for which your broker does not need your voting instruction in order to vote your shares.

Votes Required

The votes required for each proposal is as follows:

Election of Directors. In an uncontested election of directors, to be elected, a director nominee must receive affirmative votes representing a majority of the votes cast by the holders of shares present in person or represented by proxy at our Annual Meeting (a "majority vote").

A majority of votes cast means that the number of votes cast "for" a director's election exceeds the number of votes cast "against" that director's election. Under a majority voting standard, abstentions and broker non-votes are not counted as votes "for" or "against" a director nominee and will have no effect on the outcome of this proposal. Brokers, as nominees for the beneficial owner, may not exercise discretion in voting on this matter and may only vote on this proposal as instructed by the beneficial owner of the shares.

If you sign and submit your proxy card or voting instruction form without specifying how you would like your shares voted, your shares will be voted FOR the Board's recommendations specified below under Proposal One-Election of Directors, and in accordance with the discretion of the proxy holders with respect to any other matters that may be voted upon at the Annual Meeting. Should the Company lawfully identify or nominate substitute or additional nominees before the Annual Meeting, we will file supplemental proxy material that identifies such nominee(s), discloses whether such nominee(s) has (have) consented to being named in the proxy material and to serve if elected and includes the relevant required disclosures with respect to such nominee(s).

The Board recommends a vote "FOR" each of its nominees on the proxy card.

Appointment of Independent Registered Public Accounting Firm. Each share of our Common Stock is entitled to one vote with respect to the ratification of the appointment of BDO USA, LLP as our independent registered public accounting firm. The affirmative vote of holders of a majority in voting power of the Company's shares present in person or represented by proxy at the Annual Meeting and entitled to vote on the matter will be considered to determine the outcome of this proposal. Abstentions from voting will have the same effect as a vote against this proposal. This proposal is a "routine" matter for which your broker does not need your voting instruction in order to vote your shares. The outcome of this proposal is advisory in nature and is non-binding.

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, 2013 on the proxy card.

Advisory Vote on Executive Compensation. Each share of our Common Stock is entitled to one vote with respect to the approval, in a non-binding, advisory vote, of the compensation of our named executive officers. The affirmative vote of holders of a majority in voting power of the Company's shares present at the Annual Meeting in person or represented by proxy and entitled to vote on the matter will be considered to determine the outcome of this proposal. Abstentions from voting will have the same effect as a vote against this proposal, and broker non-votes will have no effect on the outcome of this proposal. Brokers, as nominees for the beneficial owner, may not exercise discretion in voting on this matter and may only vote on this proposal as instructed by the beneficial owner of the shares. The outcome of this proposal is advisory in nature and is non-binding.

The Board of Directors recommends a vote "FOR" the approval of the compensation of our named executive officers on the proxy card.

Voting of Proxies

If you are a stockholder whose shares are registered in your name, you may vote your shares by one of the following three methods:

- **Vote by Internet**, by going to the web address www.proxypush.com/abraxas and following the instructions for Internet voting shown on the enclosed proxy card.
- **Vote by Telephone**, by dialing (866) 390-5384 and following the instructions for telephone voting shown on the enclosed proxy card.
- **Vote by Proxy Card**, by completing, signing, dating and mailing the enclosed proxy card in the envelope provided. If you vote by Internet or telephone, please do not mail your proxy card.

The deadline for voting electronically through the internet or by telephone is 11:59 p.m., Eastern Time, on May 13, 2013.

If your shares are held in "street name" (through a broker, bank or other nominee), you may receive a separate voting instruction form with this Proxy Statement, or you may need to contact your broker, bank or other nominee to determine whether you will be able to vote electronically using the internet or telephone.

PLEASE NOTE THAT IF YOUR SHARES ARE HELD OF RECORD BY A BROKER, BANK OR OTHER NOMINEE AND YOU WISH TO VOTE AT THE MEETING, YOU WILL NOT BE PERMITTED TO VOTE IN PERSON AT THE MEETING UNLESS YOU FIRST OBTAIN A LEGAL PROXY ISSUED IN YOUR NAME FROM THE RECORD HOLDER.

The proxies identified on the proxy card will vote the shares of which you are stockholder of record in accordance with your instructions. If you sign and return your proxy card without giving specific voting instructions, the proxies will vote your shares "FOR" the nominated slate of directors and "FOR" each of the other proposals. The giving of a proxy will not affect your right to vote in person if you decide to attend the meeting.

Stockholder of Record. If your shares are registered directly in your name or with our transfer agent, American Stock Transfer & Trust Company, LLC, 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, in order to vote these shares in person at the meeting you must obtain a legal proxy from your broker, bank or other nominee. 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.

Whether you vote by telephone, internet or by mail, you can change or revoke your proxy before it is voted at the meeting by:

- submitting a new proxy card bearing a later date;
- voting again by telephone or the internet at a later time;
- giving written notice before the meeting to our Secretary at the address set forth on the cover of this Proxy Statement stating that you are revoking your proxy; or
- attending the meeting and voting your shares 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 a broker, bank or other nominee must bring a legal proxy from his, her or 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

The cost of soliciting proxies in the accompanying form will be borne by Abraxas. Proxies are being solicited by mail, telephone, fax, email, town hall meetings, press releases, press interviews or the Company's Investor Relations website. In addition to solicitations by mail, a number of officers, directors and regular employees of ours may, at no additional expense to us, solicit proxies in person or by telephone. We have hired Morrow & Co., LLC to assist in the solicitation of proxies at a fee estimated not to exceed $50,000. In addition, we have agreed to reimburse Morrow & Co., LLC for its reasonable out-of-pocket expenses. We will also make arrangements with brokerage firms, banks and other nominees to forward proxy materials to beneficial owners of shares and will reimburse such nominees for their reasonable costs.

Our website address is included several times in this proxy statement as a textual reference only and the information in the website is not incorporated by reference into this proxy statement.

If you have any questions about voting your shares or attending the Annual Meeting, please contact our proxy solicitor, Morrow & Co., LLC, toll free at (888) 836-9724.

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 2013 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, which we have elected **NOT** to use for the 2013 Annual Meeting, 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 2013 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 cost 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.

BACKGROUND TO POTENTIAL CONTESTED SOLICITATION

On November 27, 2012, Gregory Taxin and Robert Wenzel of the Clinton Group sent, and publicly disclosed, a letter to the Board of Directors of Abraxas Petroleum Corporation. In the letter, the Clinton Group stated its belief that the Company was undervalued in the stock market, given its assets and the opportunity to exploit those assets to generate meaningfully more cash flow and profit.

On December 3, 2012, Geoffrey R. King, our Vice President and Chief Financial Officer, met with Mr. Taxin, Mr. Wenzel, Paul Wesoly and North Lennox at the Clinton Group's offices in New York. Mr. King discussed the Clinton Group's letter with Mr. Taxin and the Clinton representatives and referred to the Company's presentation made in September 2012 at the Independent Petroleum Association of America's ("IPAA") Oil and Gas Symposium in San Francisco and the presentation given on December 3, 2012 at the Dahlman Rose Energy Conference ("Dahlman Rose") in New York. Copies of the IPAA and Dahlman Rose presentations were filed in our Current Reports on Form 8-K filed with the SEC on September 24, 2012 and November 30, 2012, respectively, and are available on the SEC's website at www.sec.gov.

Subsequent to this meeting on December 20, 2012, Mr. Watson had a telephone conversation with Mr. Taxin during which Mr. Taxin reiterated the Clinton Group's position stated in the November 27 letter.

There was no further communication between the Company and the Clinton Group until February 7, 2013 at which time the Clinton Group informed the Company that it had been interviewing "qualified" board candidates and requested that the Company send the necessary documents to allow the Clinton Group to nominate "qualified" candidates to the Board. The Company promptly complied. Mr. Taxin and Mr. Wenzel telephoned Mr. Watson on February 11, 2013 to discuss their intentions to nominate board members. Mr. Watson informed the Clinton Group representatives that this was a board decision.

On March 4, 2013, the Company received a letter from the Clinton Group informing the Company of the Clinton Group's intention to nominate three directors: Katherine T. Richard, William H. Armstrong, III and James W. McFarland. On March 12, 2013, Messrs. Watson and King received an e-mail from Mr. Taxin in which Mr. Taxin stated that the Clinton Group was beginning work on its proxy materials but before spending "a lot of money on lawyers" that he wanted to have a conversation with Mr. Watson to see if there was common ground. On March 13, 2013, Mr. Taxin, George E. Hall, President, Chief Executive Officer and Chief Investment Officer of the Clinton Group, and Mr. Wenzel called Messrs. Watson and King. Mr. Watson informed Mr. Taxin that the Abraxas Board would be meeting on March 13 and 14 and that management would be recommending to the Board that the head of the Nominating and Corporate Governance Committee, Dennis Logue, interview each of the Clinton Group candidates. Mr. Taxin noted that the Clinton Group had talked to a number of very qualified candidates who did not want to get involved in a public proxy fight, but who might be available if the Company could reach some agreement. Mr. Hall then asked if Abraxas could replace "some" of the Company's members with "some" of the Clinton Group's candidates. Mr. Taxin then followed with some detail as to how new directors on the Board might give the public assurance that the Company was proceeding with its business plan as expeditiously as possible. Importantly, Mr. Taxin stated that he did not have any issues with Abraxas' business plan going forward other than it was not proceeding as quickly as the Clinton Group would hope. He also stated that he had been in touch with a number of the Company's stockholders, and although he could not solicit proxies, he felt comfortable that he would prevail in a proxy contest. He claimed his only interest was seeing a higher share price and was comfortable with the Company's long term value.

The Nominating and Corporate Governance Committee of the Board of Directors, consisting of Messers. Logue, Cox and Powell, interviewed each of the Clinton Group's candidates on March 18, 2013. Messrs. Bartlett, and Karrash also participated. Messrs. Carter, Melton and Russell, our nominees to the Board, along with our Chairman, Mr. Watson, did not participate on the call. In addition, at Mr. Hall's request, Mr. Watson interviewed one of the candidates on March 20, 2013. The committee carefully considered each of the director candidates proposed by the Clinton Group together with the three director nominees named herein. On March 20, 2013, the Nominating and Corporate Governance Committee unanimously determined that it was in the best interest of the Company and its stockholders to nominate the three director nominees named herein and not to nominate any of the candidates proposed by the Clinton Group. The Board unanimously accepted the recommendations of the Nominating and Corporate Governance Committee. Messrs. Carter, Melton and Russell did not participate in this vote.

On March 29, 2013, we entered into an agreement (the "Settlement Agreement") with the Clinton Group, Inc. and certain of its affiliates and associates (collectively, the "Clinton Group") to settle a potential proxy contest pertaining to the election of directors to Abraxas' Board of Directors at the Annual Meeting. Pursuant to the Settlement Agreement:

- Abraxas increased the size of the Board to ten members, effective immediately prior to the 2013 Annual Meeting. Upon the recommendation of the Nominating and Governance Committee of the Board of Directors and the unanimous approval of the Board of Directors, Abraxas nominated Jerry J. Langdon as a Class III director of Abraxas for election at the 2013 Annual Meeting for a term of office expiring at the 2016 annual meeting of the stockholders of Abraxas and the Clinton Group approved Mr. Langdon's nomination; and

- Abraxas agreed to appoint Katherine T. Richard to fill a vacancy resulting from the retirement of C. Scott Bartlett, Jr. as a director for a term of office expiring at the 2014 annual meeting of the stockholders of Abraxas. Mr. Bartlett's retirement will be effective immediately following the Annual Meeting. Ms. Richard was one of the three nominees of the Clinton Group.

If Mr. Langdon or Ms. Richard (or any successor designated by the Clinton Group) should be rendered unable to serve on the Board by reason of death or disability or resign from the Board, the Clinton Group is entitled to designate a replacement for such director, subject to Abraxas' consent. If the Clinton Group's aggregate beneficial ownership of Abraxas Common Stock decreases to less than 2.0% of the Common Stock outstanding at any time or the Clinton Group receives notice from Abraxas of a material breach by the Clinton Group of any obligation under the Settlement Agreement and such material breach has not been cured within 14 days after the Clinton Group's receipt of such notice, then the Clinton Group will not be able to designate a replacement for Mr. Langdon or Ms. Richard.

The Clinton Group has agreed to cause all shares of Abraxas Common Stock beneficially owned by them to be present and voted for all of the directors nominated by the Board for election at the Annual Meeting, withdrew its nomination of three candidates for election as directors of Abraxas at the Annual Meeting and agreed to immediately cease all efforts related to their own proxy solicitation. The Clinton Group and Abraxas also agreed to a mutual release of claims in connection with, relating to or resulting from the Clinton Group's efforts to replace certain members of the Board.

Further, the members of the Clinton Group have agreed to observe normal and customary standstill provisions during the period beginning on the date of the Settlement Agreement until the earlier of (i) 14 days after Abraxas receives notice from the Clinton Group of a material breach by Abraxas of any obligation under the Settlement Agreement which has not been cured; and (ii) the business day immediately following the 2015 annual meeting of stockholders of Abraxas (the "2015 Annual Meeting") (such period, the "Standstill Period") The standstill provisions provide, among other things, that the members of the Clinton Group will not:

- solicit (as such term is used in the proxy rules of the Securities and Exchange Commission) proxies or consents to vote any securities of Abraxas, or make, or in any way participate in, any "solicitation" of any "proxy" within the meaning of Rule 14a-1 promulgated by the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), to vote any shares of Abraxas common stock ("Common Stock") with respect to the election or removal of directors, or become a participant" in any "contested solicitation" for the election or removal of directors with respect to Abraxas (as such terms are defined or used in the Exchange Act and the rules promulgated thereunder), other than solicitations or acting as a participant in support of all of Abraxas' nominees;
- form, join or in any way participate in any "group" (within the meaning of Section 13(d)(3) of the Exchange Act) with respect to the Common Stock (other than a group comprised solely of the Clinton Group and its affiliates and associates);
- deposit any Common Stock in any voting trust or subject any Common Stock to any arrangement or agreement with respect to the voting of any Common Stock, other than any such voting trust, arrangement or agreement solely among the Clinton Group;
- subject to certain exceptions, otherwise act, alone or in concert with others, to make any public statement critical of Abraxas, its directors or management;
- control or seek to control the Board;
- seek or encourage any person to submit nominations in furtherance of a "contested solicitation" for the election or removal of directors with respect to Abraxas; or
- make any proposal for consideration by stockholders at any annual or special meeting of stockholders or (B) make any offer or proposal (with or without conditions) with respect to a merger, acquisition, disposition or other business combination involving the Clinton Group and Abraxas; provided, however, that nothing in the Settlement Agreement limits the ability of any member of the Clinton Group, or its respective affiliates and associates, except as otherwise provided in the Settlement Agreement, to vote its shares of Common Stock on any matter submitted to a vote of the stockholders of Abraxas.

A copy of the Settlement Agreement was filed as an Exhibit to our Current Report on Form 8-K that we filed with the SEC on April 4, 2013.

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, four Class III directors are to be elected for a term of three years to hold office until the expiration of their term in 2016, or until a successor has been elected and duly qualified. The nominees for Class III director are Harold D. Carter, Jerry J. Langdon, Brian L. Melton and Edward P. Russell. Messrs. Carter, Melton and Russell are currently directors. Mr. Langdon was nominated by Abraxas and approved by the Clinton Group pursuant to the terms of the Settlement Agreement. In connection with the Settlement Agreement, C. Scott Bartlett, Jr., a director of Abraxas since 1999, notified Abraxas that he would retire from the Board, effective immediately following the Annual Meeting. Under the terms of the Settlement Agreement, Katherine T. Richard, one of the Clinton Group's nominees, will fill the vacancy created by Mr. Bartlett's retirement.

Each of the director nominees named in this proxy statement has agreed to serve as a director if elected, and we have no reason to believe that any nominee will be unable to serve. In the event that before the annual meeting one or more nominees named in this proxy statement should become unable or unwilling to serve, the persons named in the enclosed proxy will vote the shares represented by any proxy received by our Board of Directors for such other person or persons as may thereafter be nominated for director by the Nominating and Corporate Governance Committee and our Board of Directors.

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

The following table sets forth the names, ages, and positions of the directors of Abraxas. The term of the Class I directors expires in 2015, the term of the Class II directors expires in 2014 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	62	Chairman of the Board, President and Chief Executive Officer	I
Harold D. Carter Dallas, Texas	74	Director	III
Ralph F. Cox Fort Worth, Texas	80	Director	II
W. Dean Karrash North Wales, Pennsylvania	51	Director	I
Jerry J. Langdon(1) Houston, Texas	60	Director	III
Dennis E. Logue Enfield, New Hampshire	69	Director	II
Brian L. Melton Overland Park, Kansas	43	Director	III
Paul A. Powell, Jr. Roanoke, Virginia	67	Director	I
Katherine T. Richard(2) Oklahoma City, Oklahoma	30	Director	II
Edward P. Russell Stilwell, Kansas	49	Director	III

(1) Pursuant to the terms of the Settlement Agreement, Mr. Langdon has been nominated by our Board of Directors as a Class III director of Abraxas for election at the Annual Meeting for a term of office expiring at the 2016 annual meeting of the stockholders of Abraxas and the Clinton Group has approved Mr. Langdon's nomination.

(2) Pursuant to the terms of the Settlement Agreement, Ms. Richard was designated by the Clinton Group to fill a vacancy resulting from the retirement of C. Scott Bartlett, Jr. as a director for a term of office expiring at the 2014 annual meeting of the stockholders of Abraxas. Mr. Bartlett's retirement will be effective immediately following the Annual Meeting.

Director Nominees

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 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 2003. Mr. Carter also previously served as a director of Brigham Exploration Company, a publicly-traded oil and gas company, from 1998 to 2011 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.

Mr. Carter brings invaluable perspective and industry-specific business acumen and managerial experience to the Board as the former President and COO of Sabine Corporation and as an industry veteran with decades of exploration and production experience. In particular, we believe that Mr. Carter's tenure as a director of Brigham Exploration is particularly valuable to us because Brigham's principal area of activity was the Williston Basin, where it targeted the Bakken, Three Forks and Red River formations. Brigham was acquired in 2011 by Statoil ASA for approximately $4.4 billion. The knowledge and experience Mr. Carter has attained through his service on other public company boards also enables Mr. Carter to provide a keen understanding of various corporate governance matters.

Jerry J. Langdon currently works as a private investor. Most recently, Mr. Langdon was Chief Administrative and Compliance Officer of Energy Transfer Partners ("ETP"), a multi-billion dollar company specializing in the gathering, processing, transportation and storage of natural gas and natural gas liquids in the U.S. Prior to ETP, Mr. Langdon was Chief Administrative and Compliance Officer for Reliant Energy. Mr. Langdon has also held senior executive positions with El Paso Energy Partners and has served as a Director of several public and private boards. In October 1988, Mr. Langdon was appointed to the Federal Energy Regulatory Commission by President Ronald Regan and served in that capacity until 1993. Mr. Langdon has authored numerous articles on the natural gas and electric industries, which have been published in various industry trade magazines. Mr. Langdon holds a Bachelor of Science Communications from the University of Texas.

We believe Mr. Langdon's extensive experience in the energy industry will make him a valuable addition to our Board.

Brian L. Melton, a director of Abraxas since October 2009, has served as Vice President of Business Development / Corporate Strategy of Inergy, L.P. (NYSE:NRGY), a publicly-traded master limited partnership that specializing in providing midstream crude oil, natural gas and natural gas liquids services to producers and midstream providers in many of the major U.S. shale plays including the Bakken, Eagle Ford and Marcellus / Utica areas, 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 Securities 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.

We believe that Mr. Melton's operational and business experience (particularly in the U.S. shale plays in which the Company operates), as well as Mr. Melton's prior oil and gas investment banking experience help him bring unique insight to our Board and his financial experience is beneficial to our audit committee.

Edward P. Russell, a director of Abraxas since October 2009, has served as a Director of Tortoise Capital Resources Corp., one of the largest energy investors in the U.S. with over $10 billion in assets under management since April 2007. From 2007 to 2012, Mr. Russell served as President of Tortoise Capital. 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. Mr. Russell previously served as a director of Abraxas General Partner, LLC, the general partner of Abraxas Energy Partners, L.P.

We believe Mr. Russell's experience as an oil and gas investor and as an energy investment banker brings an important skill set to the Board.

The Board unanimously recommends using the enclosed proxy card to vote FOR each of the Board's four nominees for Director.

Directors with Terms Expiring in 2014 and 2015

Robert L.G. Watson, has served as Chairman of the Board, President, Chief Executive Officer and a director of Abraxas since 1977. 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.

Mr. Watson has been involved in the oil and gas industry for his entire business career and is the founder of Abraxas. He has developed a wide network of personal and business relationships within the oil and gas industry. His strong engineering and financial background combined with his many years of operational experience throughout changing conditions in the market and industry provide him with the ability to successfully lead the Company

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 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 CH2M Hill Companies, an engineering and construction firm, 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.

Mr. Cox has many years of prior experience with major oil and gas companies. Mr Cox continues his involvement in the industry through his other directorship positions. His executive-level perspective and decision making abilities continue to prove beneficial to the Company.

W. Dean Karrash, was an advisory director of Abraxas from November 2011 to May 2012 at which time he was elected to the Board of Directors. Mr. Karrash serves as Executive Vice President and Chief Financial Officer of Burke, Lawton, Brewer & Burke, LLC, a securities brokerage firm. Mr. Karrash joined the firm in 2004 and also serves as a Portfolio Manager with BLB&B Advisors, LLC. Mr. Karrash has over twenty five years of experience in the financial services industry and previously served as President and Chief Executive Officer of Rutherford, Brown & Catherwood, LLC and Chief Financial Officer of Walnut Asset Management, LLC. Early in Mr. Karrash's career, he served as Vice President of Finance for Lincoln Investment Planning Inc. and as a Senior Manager with Pricewaterhouse Coopers (formally Coopers & Lybrand). Mr. Karrash is currently a member of FINRA's Financial and Operations Committee and a past member of the Small Firm Advisory Board and District 9 Business Conduct Committee. Mr. Karrash is a Certified Public Accountant, Certified Financial Planner and is registered with FINRA and holds Series 7, 24, 27, 53 and 65 licenses. Mr. Karrash received a Bachelor of Science degree in Accounting from Pennsylvania State University and a Master of Business Administration degree from Temple University's Executive MBA program.

Through his role as Executive Vice President of Burke, Lawton, Brewer & Burke, Mr. Karrash provides our Board with investment and financial experience from the standpoint of an investor and as a stockholder. In addition, Mr. Karrash is a Certified Public Accountant and is an audit committee financial expert as defined by SEC rules.

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 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 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 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 Crossroads Academy. Mr. Logue holds degrees from Fordham College, Rutgers, and Cornell University.

Mr. Logue has significant business, financial and administrative experience and his broad based experiences across a number of industries are particularly beneficial in his service on our Nominating and Compensation Committees.

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 of the Boy Scouts of America. Mr. Powell attended Emory & Henry College and graduated from National Business College with a degree in Accounting.

Through his roles at various investment and operating companies, Mr. Powell provides our Board with investment and financial experience. Mr. Powell has extensive historical knowledge about our Company through his investment in a number of drilling partnerships which became a part of Abraxas in 1991.

Katherine Taaffe Richard, is the Founder and current Chief Executive Officer of Warwick Energy Group, an oil and gas company focused on conventional and unconventional development and exploration in the United States, Europe and the Middle East. Ms. Richard has been employed by Warwick Energy Group since March 2010. Since March 2009, Ms. Richard has been employed by or consulted to MSDC Management, L.P. or MSD Capital, L.P., where she focuses on international energy investments. Prior to joining MSDC Management, Ms. Richard was employed by Serengeti Asset Management, where she led the team responsible for oil and gas, metals and mining and sovereign debt investing. Prior to Serengeti, Ms. Richard held several posts at Goldman, Sachs & Co., including as an investment banker to exploration and production companies in the oil and gas industries. Ms. Richard is a Natural Resources Advisor to the Institute for Effective States and an Advisory Council member of Microvest Capital Funds, a private microfinance investment firm with investments in more than 50 microfinance institutions in 25 countries. At the World Economic Forum's 2013 Davos session, Ms. Richard was selected to represent the United States as one of the World Economic Forum's Young Global Leaders for the 2013-14 year. Ms. Richard received her undergraduate degree in History from Harvard College.

We believe Ms. Richard's experience in the financial and energy industry and her knowledge and intellect will add a new perspective to our Board.

Directors Emeritus

Franklin A. Burke, a director emeritus 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. The Board voted to appoint Mr. Burke as a Director Emeritus following his retirement in 2012.

C. Scott Bartlett, Jr., will become a director emeritus effective immediately following the Annual Meeting. Mr. Bartlett has served as a director of Abraxas since 1999 and 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.

Messers. Bartlett and Burke serve at the pleasure of the Board and may be terminated as Directors Emeritus at any time upon consent of a majority of the Board of Directors. Messers. Bartlett and Burke have the right to receive timely notice and information regarding, and to attend and participate in all, meetings of the Board, but does not have the right to vote at the meetings. The Board may, in its discretion without Messers. Bartlett's and Burke's consent, at any meetings at which either of them is in attendance, hold an executive session, at which Messers. Bartlett and Burke may not be present. Except for purposes of indemnification, Messers. Bartlett and Burke are not deemed to be "directors" of Abraxas.

Composition of the Board of Directors

The Company believes that its Board as a whole should encompass a diverse range of talent, skill, 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 believes that the Board of Directors should be composed of directors with 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 pages 8 through 10 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, Cox and Langdon have strong backgrounds in the oil and gas industry and Messrs. Karrash, Logue and Powell have strong backgrounds in the financial / banking community. Messrs. Melton and Russell and Ms. Richard have strong backgrounds in both the oil and gas industry and the financial / banking community.

Meeting Attendance

During the fiscal year ended December 31, 2012, the Board of Directors held five meetings, the Audit Committee held four meetings, the Compensation Committee held two meetings and the Nominating and Corporate Governance Committee held one meeting. During 2012, each director attended at least 75% of all Board and applicable Committee meetings and other than Mr. Watson, our Chairman of the Board, President and Chief Executive Officer, each director received compensation for their service to Abraxas for their role as director. See "Executive Compensation—Compensation of Directors." Abraxas encourages, but does not require, directors to attend the annual meeting of stockholders; however, such attendance allows for direct interaction between stockholders and members of the Board of Directors. At Abraxas' 2012 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. During 2012, the Audit Committee consisted of Messrs. Bartlett (Chairman), Karrash, Melton and Powell. Following the effectiveness of Mr. Bartett's retirement immediately following the Annual Meeting, Messers. Melton (Chairman), Karrash, and Powell will be the members of the Audit Committee. The Board of Directors has determined that each of Messrs. Melton and Karrash is an audit committee financial expert as defined by SEC rules. The Audit Committee Report, which appears on page 37, more fully describes the activities and responsibilities of the Audit Committee. Mr. King, Mr. Krog and representatives from BDO USA, LLP, the Company's independent registered public accounting firm, attend each meeting of the Audit Committee. In addition, the representatives from BDO USA, LLP and the Audit Committee meet in executive session at each meeting.

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 18, 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. Logue (Chairman), Cox 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 or future 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: Harold D. Carter, Ralph F. Cox, W. Dean Karrash, Jerry J. Langdon, Brian L. Melton, Dennis E. Logue, Paul A. Powell, Jr., Katherine T. Richard 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, as well as other identified risks, including information technology. 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 2012. No member of the Compensation Committee was at any time during 2012 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. 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 2012.

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 be in a position to properly exercise his or her duties of loyalty and care. Candidates should also exhibit proven leadership capabilities, high integrity and experience with a high level of responsibility within his or her chosen fields, and have the ability to quickly understand complex principles of, but not limited to, business, finance and the oil and gas business. 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 2014 Abraxas Annual Meeting" beginning on page 40 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.

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 22, 2013, the number and percentage of outstanding shares of common stock of Abraxas indicated in the following table. Abraxas' Board has adopted stock ownership guidelines. Except as otherwise noted below, the address for each of the beneficial owners is c/o Abraxas Petroleum Corporation, 18803 Meisner Drive, San Antonio, Texas 78258. 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	1,918,374(2)	2.0%
Geoffrey R. King	55,000(3)	*
Lee T. Billingsley	498,989(4)	*
William H. Wallace	406,744(5)	*
Stephen T. Wendel	510,113(6)	*
G. William Krog, Jr.	123,236(7)	*
Peter A. Bommer	163,491(8)	*
C. Scott Bartlett, Jr.	184,373(9)	*
Franklin A. Burke	5,248,801(10)	5.6%
Harold D. Carter	274,624(11)	*
Ralph F. Cox	544,449(12)	*
W. Dean Karrash	32,050(13)	*
Dennis E. Logue	216,148(14)	*
Brian L. Melton	114,000(15)	*
Paul A. Powell, Jr.	266,828(16)	*
Edward P. Russell	97,014(17)	*
NorthPointe Capital, LLC	7,556,608(18)	8.1%
Lehman Brothers MLP Opportunity Fund	5,451,426(19)	5.9%
The Vanguard Group	5,150,986(20)	5.4%
BlackRock Inc.	5,053,257(21)	5.4%
All Officers and Directors as a Group (17 persons)	10,654,234	11.5%

* Less than 1%

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

(2) Includes 90,000 shares issuable upon exercise of vested options granted pursuant to the Abraxas Petroleum Corporation 1994 Long Term Incentive Plan (the "1994 LTIP"), 569,937 shares issuable upon exercise of vested options granted pursuant to the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (the "2005 Employee Plan") and 39,797 shares in a retirement account.

(3) Includes 50,000 restricted shares awarded to Mr. King on the commencement of his employment in September 2012.

(4) Includes 229,571 shares issuable upon exercise of vested options granted pursuant to the 2005 Employee Plan and 35,200 shares in a retirement account.

(5) Includes 15,000 shares issuable upon exercise of vested options granted pursuant to the 1994 LTIP, 231,948 shares issuable upon exercise of vested options granted pursuant to the 2005 Employee Plan and 14,667 shares in a retirement account.

(6) Includes 228,133 shares issuable upon exercise of vested options granted pursuant to the 2005 Employee Plan and 102,098 shares in a retirement account.

(7) Includes 2,500 shares issuable upon exercise of vested options granted pursuant to the 1994 LTIP, 85,811 shares issuable upon exercise of vested options granted pursuant to the 2005 Employee Plan and 8,986 shares in a retirement account.

(8) Includes 77,050 shares issuable upon exercise of vested options granted pursuant to the 2005 Employee Plan and 17,116 shares in a retirement account.

(9) Includes 86,793 shares issuable upon exercise of vested 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.

(10) Includes 45,000 shares issuable upon exercise of certain option agreements, 120,000 shares issuable upon exercise of vested 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 1,405,279 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.

(11) Includes 132,500 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan, 7,577 shares in a family trust and 40,598 shares in a retirement account.

(12) Includes 132,500 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan.

(13) Includes 12,000 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan.

(14) Includes 132,500 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan.

(15) Includes 88,750 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan.

(16) Includes 45,000 shares issuable upon exercise of certain option agreements, 132,500 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan and 27,277 shares in various entities managed by Mr. Powell.

(17) Includes 88,750 shares issuable upon exercise of vested options granted pursuant to the 2005 Directors Plan.

(18) NorthPointe Capital, LLC has sole dispositive powers over 7,556,608 shares and sole voting power over 5,210,034 shares. The members of NorthPointe, LLC disclaim beneficial ownership to all such shares. The address of NorthPointe Capital, LLC is 101 W. Big Beaver, Suite 745, Troy, Michigan 48084.

(19) 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 to all such shares. 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.

(20) The Vanguard Group has sole dispositive powers over 5,048,725 shares, shared dispositive powers over 102,261 shares and sole voting power over 103,961 shares. The members of The Vanguard Group disclaim beneficial ownership to all such shares. The address of The Vanguard Group is 100 Vanguard Blvd, Malvern, PA 19355.

(21) BlackRock Inc. has sole dispositive powers over 5,053,257 shares and sole voting power over 5,053,257 shares. The members of BlackRock Inc. disclaim beneficial ownership to all such shares. The address of BlackRock Inc. is 40 East 52nd Street, 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, 2012.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by security holders	2,902,467	$ 2.76	4,456,851
Equity compensation plans not approved by security holders	90,000	$ 2.64	—

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 2012, 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 OFFICERS

The following table sets forth the names, ages and positions of the executive officers of Abraxas.

Name and Municipality of Residence	Age	Office
Robert L.G. Watson San Antonio, Texas	62	Chairman of the Board, President and Chief Executive Officer
Geoffrey R. King San Antonio, Texas	32	Vice President—Chief Financial Officer
Lee T. Billingsley San Antonio, Texas	60	Vice President—Exploration
Peter A. Bommer San Antonio, Texas	56	Vice President—Engineering
William H. Wallace Blanco, Texas	55	Vice President—Operations
Stephen T. Wendel San Antonio, Texas	63	Vice President—Land & Marketing and Secretary
G. William Krog, Jr. San Antonio, Texas	59	Chief Accounting Officer

Robert L.G. Watson has served as Chairman of the Board, President, Chief Executive Officer and a director of Abraxas since 1977. See page 9 for more information.

Geoffrey R. King has served as Vice President—Chief Financial Officer since September 2012. Prior to joining Abraxas, Mr. King worked at Van Eck Associates from 2007 to 2012 as a Senior Energy Analyst with a focus on natural resource equities and commodities. Prior to that, he served as a Senior Analyst in the Global Power and Energy Group at Merrill Lynch and served in various roles at Petrie Parkman. Mr. King is a CFA Charterholder and holds Series 7, 63, 86 and 87 licenses. Mr. King holds a B.A. in Economics and History from Davidson College.

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.

Peter A. Bommer has served as Vice President—Engineering since 2012 and as Manager of Special Projects since 2007. Prior to joining Abraxas, Mr. Bommer owned and ran the day-to-day operations of Bommer Engineering, a privately held engineering firm for over 25 years. Mr. Bommer received a Bachelor of Science in Petroleum Engineering degree from the University of Texas in 1978 and a Master of Theology degree from Dallas Theological Seminary in 1999. Mr. Bommer also holds the Professional Engineer designation.

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.

G. William Krog, Jr. has served as Chief Accounting Officer since 2011. Mr. Krog joined Abraxas in 1995 and most recently served as Information Systems / Financial Reporting Director. Prior to joining Abraxas, Mr. Krog was an independent accountant in private practice. Mr. Krog received a Bachelor of Business Administration degree from the University of Texas at Austin in 1976 and is a Certified Public Accountant.

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 2012.

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 factors beyond an employee's control.
- 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. 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 2012 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 2012 are set forth below in the Summary Compensation Table. For 2012, base salaries, paid as cash compensation, were $1,130,618 with Mr. Watson receiving $395,550. 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. 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 Abraxas' previous equity ownership in Blue Eagle Energy, LLC, and 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 equity 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 financial statements.

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.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2011 and 2012:

	December 31,	
(in thousands)	**2011**	**2012**
PV-10	$298,001	$316,862
Present value of future income taxes discounted at 10%	(28,919)	(38,717)
Standardized measure of discounted future net cash flows	$269,082	$278,145

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, in addition to other adjustments for other factors out of an employee’s control. 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 2011, the calculated NAV per share was $2.57 (utilizing commodity prices as of December 31, 2010 and the development costs included in our reserve report prepared by DeGoyler and MacNaughton) and the calculated NAV per share at the end of 2011 (utilizing commodity prices as of December 31, 2011 and the development costs included in our reserve report prepared by DeGoyler and MacNaughton) was $2.41, a 6% decrease. As a result, management did not qualify to receive a bonus under the incentive performance bonus plan. During the March 9, 2012 Board meeting, the Compensation Committee recommended and the board approved an adjustment to the annual incentive performance bonus plan to compensate for factors beyond employees’ control, such as development costs. The Board decided that because development costs were increasing rapidly and that the costs included in the Company’s independent reserve reports reflected this price trend, the Company would, starting in 2012, make an adjustment, up or down, to future development costs for the proved and probable PV-10 calculations as reflected in the reserve report based on the Company’s actual development costs when determining PV-10. Using this revised calculation at the beginning of 2011, the calculated NAV per share would have been $2.57 utilizing commodity prices and development costs as of December 31, 2010 and the calculated NAV per share at the end of 2011 (utilizing commodity prices and development costs as of December 31, 2010) would have been $3.25, a 35% increase. Given the discrepancy when increased development costs were taken into account and inability to retroactively adjust the calculation, the Compensation Committee recommended, and the Board approved, a pro-rata bonus (based on applicable bonus percentage levels) for all non-field employees, including the eligible named executive officers, of $750,000 contingent on the closing of an Eagle Ford transaction. These bonuses were paid to eligible employees in December 2012 after the closing of the Nordheim transaction in the Eagle Ford shale.

At the end of 2012, the calculated NAV per share was $4.74 (utilizing commodity prices and development cost as set forth in our reserve report for 2012) and the calculated NAV per share at the end of 2011 (utilizing commodity prices and development cost as of December 31, 2011 as set forth in the reserve report for 2011) was $4.08, a 16% increase. As a result, the Compensation Committee recommended annual bonus awards for our executive officers at a board meeting in March 2013 and the Board approved these annual bonuses. The following table details the 2012 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	One Time Pro Rata Eagle Ford Incentive Bonus	Total Bonus
Robert L.G. Watson	$400,000	22%	70%	$88,000	$82,173	$170,173
Geoffrey R. King[3]	230,000	22%	70%	16,867	0	16,867
Lee T. Billingsley	226,000	22%	70%	49,720	46,731	96,451
Peter A. Bommer	215,000	22%	70%	47,300	42,549	89,849
William H. Wallace	226,000	22%	70%	49,720	46,731	96,451
Barbara M. Stuckey[4]	0	0%	70%	0	0	0

(1) Base annual salaries in effect at the end of the year.
(2) 1% for the first 10%, then 2% for each percent increase over the first 10%.
(3) Mr. King's employment commenced on September 4, 2012 and thus he was not eligible for the pro-rata incentive bonus on an Eagle Ford transaction approved in May 2012, and his incentive bonus was pro-rated to his four months of employment in 2012.
(4) Ms. Stuckey resigned in July 2012.

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 9,200,000 shares of Abraxas common stock are 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. 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 2012 was $17,000 for employees under the age of 50 and $22,500 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.

2013 Compensation Decisions

Base Salaries. In general, base salaries for 2013 increased 5.5% from 2012 for our named executive officers to adjust for increases in the cost of living.

Assessment of Compensation Policies and Practices

The Company and the Compensation Committee have 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 the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission 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	2012	395,550	15,835	7,761	51,951	170,173	8,575	649,395
President, Chief Executive	2011	377,650	14,700	28,466	203,463	—	8,575	632,854
Officer and Chairman of the Board	2010	360,500	114,000	—	137,485	254,800	8,575	875,360
Geoffrey R. King	2012	76,667	2,948	99,500	248,105	16,867	—	444,087
Vice President—Chief Financial	2011	—	—	—	—	—	—	—
Officer[8]	2000	—	—	—	—	—	—	—
Lee T. Billingsley	2012	223,838	8,692	3,530	29,352	96,451	8,575	370,438
Vice President—Exploration	2011	214,763	8,360	12,947	101,731	—	8,575	346,376
	2010	205,000	7,962	—	91,656	144,900	7,454	456,972
Peter A. Bommer	2012	210,725	8,269	2,388	27,274	89,849	7,912	346,417
Vice President—Engineering	2011	195,100	7,612	98,152	113,189	—	6,723	420,776
	2010	184,900	7,181	—	54,841	23,338	6,283	276,543
William H. Wallace	2012	223,838	8,692	3,530	29,352	96,451	20,575	382,438
Vice President—Operations	2011	214,763	8,360	12,947	101,732	—	8,575	346,377
	2010	205,000	7,962	—	91,656	144,900	7,454	456,972
Barbara M. Stuckey[9]	2012	120,254	—	—	—	—	8,575	128,829
Former Vice President, Chief	2011	214,763	8,360	8,541	99,468	—	8,575	339,707
Financial Officer and Assistant Secretary	2010	199,000	57,962	—	91,656	144,900	7,244	500,762

(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 of $15,835, $2,948, $8,692, $8,269 and $8,692 awarded to Mr. Watson, Mr. King, Dr. Billingsley, Mr. Bommer and Mr. Wallace, respectively. Mr. Watson and Ms. Stuckey were paid discretionary bonuses of $100,000 and $50,000, respectively for 2010.

(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 the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission for a discussion of all assumptions made in the calculation of this amount.

(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 the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission for a discussion of all assumptions made in the calculation of this amount. Ms. Stuckey resigned in July; therefore, her restricted stock and unvested and out-of-the-money options were forfeited and no value was recorded in the grant date fair value column.

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

(6) The amounts in this column represent contributions by Abraxas to the named executive officer's 401(k) plan account for 2010, 2011 and 2012 as well as a $12,000 vehicle allowance for Mr. Wallace in 2012.

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

(8) Mr. King joined the Company in September 2012.

(9) Ms. Stuckey resigned in July 2012.

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 in 2012. 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[1] Threshold ($)	Target ($)	Maximum ($)	All Other Stock Awards: Number of Shares of Stock (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/share)	Grant Date Fair Value of Stock and Option Awards ($)[2]
Robert L.G. Watson	03/8/2012		170,173	364,885		20,000	3.74	51,951
	08/09/2012				3,696		2.10	7,761
Geoffrey R. King	09/04/2012		16,867	53,667		200,000	1.99	248,105
	09/04/2012				50,000		1.99	99,500
Lee T. Billingsley	03/8/2012		96,451	206,407		11,300	3.74	29,352
	08/09/2012				1,681		2.10	3,530
Peter A. Bommer	03/8/2012		89,849	190,057		10,500	3.74	27,274
	08/09/2012				1,137		2.10	2,388
William H. Wallace	03/8/2012		96,451	203,418		11,300	3.74	29,352
	08/09/2012				1,681		2.10	3,530
Barbara M. Stuckey[3]	03/8/2012		—	—		11,300	3.74	29,352

(1) Awards payable under our annual bonus plan and the Eagle Ford transaction 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 amount set forth in the target column reflects the amount each named executive officer earned under the annual plan for 2012 that was paid in 2013 and the amount paid under the Eagle Ford transaction bonus plan. Please see the discussion under "Compensation Discussion and Analysis—Elements of Executive Compensation—Annual Bonuses" for more information. Please refer to column 5 of the Summary Compensation Table.

(2) The amounts in this column reflect the aggregate grant date fair value of stock awards and options granted in 2012 to the named executive officer calculated in accordance with FASB ASC Topic 718. See the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission for a discussion of all assumptions made in the calculation of this amount.

(3) Ms. Stuckey resigned in July 2012; her restricted stock and unvested and out-of-the-money options were forfeited and no value was recorded in the grant date fair value column.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

The following table provides information concerning outstanding equity awards at December 31, 2012 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 ($)**	**Option Expiration Date**	**Number of Shares of Stock That Have Not Vested[2]**	**Market Value of Shares of Stock That Have Not Vested ($)[3]**
Robert L.G. Watson	100,000	—	4.59	09/13/2015		
	41,624	—	3.60	08/28/2017		
	93,750	31,250	0.99	03/17/2019		
	200,813	66,937	1.75	10/05/2019		
	45,000	45,000	2.09	03/16/2020		
	15,000	45,000	4.72	03/15/2021		
	—	20,000	3.74	03/08/2022		
					21,159	46,338
Geoffrey R. King	—	200,000	1.99	09/04/2022		
					50,000	109,500
Lee T. Billingsley	50,000	—	4.59	09/13/2015		
	16,543	—	3.60	08/28/2017		
	37,500	12,500	0.99	03/17/2019		
	50,203	16,734	1.75	10/05/2019		
	30,000	30,000	2.09	03/16/2020		
	7,500	22,500	4.72	03/15/2021		
	—	11,300	3.74	03/08/2022		
					9,380	20,542
Peter A. Bommer	5,000	—	3.61	09/05/2007		
	3,750	3,750	0.99	03/17/2009		
	21,250	10,625	1.75	10/05/2009		
	17,950	17,950	2.09	03/16/2010		
	3,750	11,250	4.72	03/15/2011		
	6,250	18,750	3.55	08/09/2011		
	—	10,500	3.74	03/08/2022		
					24,360	53,348
William H. Wallace	15,000	—	0.68	04/24/2013		
	50,000	—	4.59	09/13/2015		
	18,920	—	3.60	08/28/2017		
	37,500	12,500	0.99	03/17/2019		
	50,203	16,734	1.75	10/05/2019		
	30,000	30,000	2.09	03/16/2020		
	7,500	22,500	4.72	03/15/2021		
	—	11,300	3.74	03/08/2022		
					9,380	20,542

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

(2) 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.

(3) The market value was calculated from the closing price of Abraxas' common stock on December 31, 2012 of $2.19 per share multiplied by the number of shares of stock that had not vested as of December 31, 2012.

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, 2012.

Name	OPTION AWARDS Number of Shares Acquired on Exercise	OPTION AWARDS Value Realized on Exercise ($)	STOCK AWARDS Number of Shares Acquired on Vesting	STOCK AWARDS Value Realized on Vesting ($)
Robert L.G. Watson	90,000	97,200[(1)]	20,459	68,265[(2)]
Geoffrey R. King	—	—	—	—
Lee T. Billingsley	37,000	72,870[(3)]	10,084	34,380[(4)]
Peter A. Bommer	—	—	16,629	50,165[(5)]
William H. Wallace	22,000	23,100[(6)]	13,705	42,238[(7)]
Barbara M. Stuckey[(8)]	156,750	96,675[(9)]	13,574	48,897[(10)]

(1) These options were exercised on November 19, 2012 (90,000). The exercise price was $0.65 and the closing price of Abraxas' common stock was $1.73. The realized value per share was $1.08.

(2) Of these stock awards, 6,375 vested on January 2, 2012, 10,615 vested on January 31, 2012, and 3,469 vested on September 10, 2012 and the closing price of Abraxas' common stock on those dates was $3.30, $3.74 and $2.17, respectively.

(3) These options were exercised on March 22, 2012 (22,000) and November 26, 2012 (15,000). The exercise prices were $0.65 and $0.68, respectively and the closing price of Abraxas' common stock was $3.11 and $1.93, respectively, for a realized value of $2.46 and $1.25 per share, respectively.

(4) Of these stock awards, 2,656 vested on January 2, 2012, 6,049 vested on January 31, 2012, and 1,379 vested on September 10, 2012 and the closing price of Abraxas' common stock on those dates was $3.30, $3.74 and $2.17, respectively.

(5) Of these stock awards, 1,062 vested on January 2, 2012, 7,317 vested on January 31, 2012, 6,250 vested on August 9, 2012, and 2,000 vested on October 6, 2012 and the closing price of Abraxas' common stock on those dates was $3.30, $3.74, $2.38 and $2.21, respectively.

(6) These options were exercised on November 13, 2012 (22,000). The exercise price was $0.65 and the closing price of Abraxas' common stock was $1.70. The realized value per share was $1.05.

(7) Of these stock awards, 2,656 vested on January 2, 2012, 6,049 vested on January 31, 2012, and 5,000 vested on September 10, 2012 and the closing price of Abraxas' common stock on those dates was $3.30, $3.74 and $2.17, respectively.

(8) Ms. Stuckey resigned in July 2012.

(9) These options were exercised on October 8, 2012. The exercise prices were $0.99 (37,500), $1.75 (89,250) and $2.09 (30,000), respectively, and the closing price of Abraxas' common stock was $2.25, for a realized value of $1.26, $0.50 and $0.16 per share, respectively.

(10) Of these stock awards, 4,250 vested on January 2, 2012 and 9,324 vested on January 31, 2012 and the closing price of Abraxas' common stock on those dates was $3.30 and $3.74, 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, 2012, we had eight non-employee directors and seven 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, 2012, the market value of Abraxas common stock was $2.19 per share. As an example, Mr. Watson, our chief executive officer, is required to own 913,242 shares of Abraxas common stock to meet the stock ownership guidelines at this price. As of December 31, 2012, one officer and two directors 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 agreement for Mr. Watson is scheduled to terminate on December 21, 2013, and is 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. King, Dr. Billingsley, Mr. Bommer and Mr. Wallace are scheduled to terminate on December 31, 2013, and are automatically extended for an additional year if by December 1 neither Abraxas nor Mr. King, Dr. Billingsley, Mr. Bommer or Mr. Wallace 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: 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.

King, Billingsley, Bommer and Wallace: 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. King, Dr. Billingsley, Mr. Bommer and Mr. Wallace 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: a lump sum payment equal to 2.99 times his annual base salary.

King, Billingsley, Bommer and Wallace: 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 and restricted stock that have been awarded to our named executive officers will vest upon any change in control. As of December 31, 2012, our named officers held 667,080 unvested options, of which 493,980 were "in-the-money". Additionally, our named officers held 114,279 shares of restricted stock, which were unvested.

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, 2012.

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	400,000	1,196,000	—	—	400,000
	Option acceleration		71,452		71,452	71,452
	Restricted stock acceleration		46,338		46,338	46,338
	Total		1,313,790		117,790	517,790
Geoffrey R. King	Severance pay	—	690,000	—	—	690,000
	Option acceleration		40,000		40,000	40,000
	Restricted stock acceleration		109,500		109,500	109,500
	Total		839,500		149,500	839,500
Lee T. Billingsley	Severance pay	—	678,000	—	—	678,000
	Option acceleration		25,363		25,363	25,363
	Restricted stock acceleration		20,542		20,542	20,542
	Total		723,905		45,905	723,905
Peter A. Bommer	Severance pay	—	645,000	—	—	645,000
	Option acceleration		10,970		10,970	10,970
	Restricted stock acceleration		53,348		53,348	53,348
	Total		709,318		64,318	709,318
William H. Wallace	Severance pay	—	678,000	—	—	678,000
	Option acceleration		25,363		25,363	25,363
	Restricted stock acceleration		20,542		20,542	20,542
	Total		723,905		45,905	723,905

(1) These amounts reflect a lump sum payment equal to the officer's annual base salary as of December 31, 2012.

(2) These amounts reflect a lump sum payment equal to 2.99x (Watson) and 3.0x (King, Billingsley, Bommer and Wallace) the named executive officer's annual base salary as of December 31, 2012. The amounts on the option acceleration row reflect 493,980 "in-the-money" unvested options for the named officers at an average potential value of $0.36 per share (the difference between the fair market value on December 31, 2012 and the exercise price of the options). Our named officers held 114,279 shares of restricted stock valued at the fair market value as of December 31, 2012.

(3) These amounts on the severance pay row reflect a 12-month extension (Watson) and a 36-month extension (King, Billingsley, Bommer, and Wallace) of each officer's respective employment agreement based on the named executive officer's annual base salary on December 31, 2012 and would be paid over the extension period. The amounts on the option acceleration row reflect 493,980 "in-the-money" unvested options for the named officers at an average potential value of $0.36 per share (the difference between the fair market value on December 31, 2012 and the exercise price of the options). Our named officers held 114,279 shares of restricted stock valued at the fair market value as of December 31, 2012.

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. During 2012, the annual retainer fee paid to each director was $27,500 (prior to April 2012) and $40,000 (after April 2012) to be paid in four quarterly cash payments, in addition to reimbursement for travel expenses to attend the quarterly meetings.

During 2012, each director was paid $1,600 for each board meeting attended and $1,100 for each committee meeting attended. The chairman of the Audit Committee received an additional annual fee of $10,500, the chairman of the Compensation Committee received an additional annual fee of $5,300 and the chairman of the Nominating and Governance Committee received 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 2012, each year at the first regular board meeting following the annual meeting, Abraxas awarded each director 10,500 options, in accordance with the terms of the 2005 Directors Plan. In April 2012, the annual award was increased to 12,000 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, 2012 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 ($)(1)	Stock Option Awards ($)(2)	Total ($)(3)
C. Scott Bartlett, Jr.	59,175	24,277	83,452
Harold D. Carter	46,475	24,277	70,752
Ralph F. Cox	51,875	24,277	76,152
W. Dean Karrash	39,100	24,277	63,377
Dennis E. Logue	48,675	24,277	72,952
Brian L. Melton	48,675	24,277	72,952
Paul A. Powell, Jr.	46,575	24,277	70,852
Edward P. Russell	44,275	24,277	68,552

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

(2) The amounts in this column reflect the aggregate grant date fair value of stock options granted in 2012 to each director calculated in accordance with FASB ASC Topic 718. See the notes to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission for a discussion of all assumptions made in the calculation of this amount.

(3) 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, 2012 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.	12,000		2.90		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	1,793	12,500	0.99		
	10,000		2.36		
	10,500		4.13		
Harold D. Carter	12,000		2.90		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	37,500	12,500	0.99		
	10,000		1.06		
	10,000		2.36		
	10,500		4.13		
Ralph F. Cox	12,000		2.90		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	37,500	12,500	0.99		
	10,000		1.06		
	10,000		2.36		
	10,500		4.13	4,250	9,308
W. Dean Karrash	12,000		2.90		
Dennis E. Logue	12,000		2.90		
	10,000		2.75		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	37,500	12,500	0.99		
	10,000		1.06		
	10,000		2.36		
	10,500		4.13		
Brian L. Melton	12,000		2.90		
	56,250	18,750	1.64		
	10,000		2.36		
	10,500		4.13	4,250	9,308
Paul A. Powell, Jr.	12,000		2.90		
	10,000		2.75		
	45,000		4.59		
	10,000		4.51		
	10,000		4.32		
	10,000		4.50		
	37,500	12,500	0.99		
	10,000		1.06		
	10,000		2.36		
	10,500		4.13		
Edward P. Russell	12,000		2.90		
	56,250	18,750	1.64		
	10,000		2.36		
	10,500		4.13		

(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, 2012 of $2.19 per share multiplied by the number of shares of stock that had not vested as of December 31, 2012.

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.

Related Party Transactions in 2012

In February 2012, the Audit Committee approved a related party transaction between Tom Coons, Vice President of Raven Drilling, LLC ("Raven"), one of Abraxas' wholly-owned subsidiaries, and Krobar Supply & Rental ("Krobar"), a company owned by Mr. Coons. Raven purchased two (2) pieces of oil field equipment from Krobar as described below for the prices indicated next to each item:

One 2006 642J John Deere loader / forklift (ID Number DW624JZ600110)	$ 98,000
One 150 hp INDECK boiler, Model Volcano Starfire ST (SN 10269-S)	97,000
Total:	$195,000

The oil field equipment is used in connection with Abraxas' Bakken / Three Forks operated activity in the Williston Basin. Because our management believed that the equipment was necessary for Raven Drilling's operations and Abraxas received third party appraisals of the equipment and the terms were deemed fair to Abraxas, the Audit Committee approved the transaction.

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, 2013. 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. Even if the selection is ratified, the Audit Committee, in its discretion, may select a different independent registered public accounting firm at any time if the Audit Committee believes that such a change would be in the best interests of our company and its stockholders. If our stockholders do not ratify the selection of BDO USA, LLP, the Audit Committee will take that fact into consideration, together with such other factors it deems relevant, in determining its next selection of an independent registered public accounting firm.

BDO USA, LLP provided audit services to Abraxas for the year ended December 31, 2012. 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.

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. This proposal is a "routine" matter for which your broker does not need your voting instruction in order to vote your shares.

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, 2013.

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 accountants required by applicable requirements of the PCAOB regarding the independent accountants' communications with the Audit Committee concerning independence, and has discussed with the independent accountants 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, 2012, 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
W. Dean Karrash
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, 2012 and December 31, 2011 and the reviews of the condensed financial statements included in Abraxas' quarterly reports on Form 10-Q for the years ended December 31, 2012 and December 31, 2011, were $530,693 and $493,615, 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, 2012 and December 31, 2011, were $0 and $0, respectively.

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, 2012 and December 31, 2011, were $201,452 and $10,250, respectively.

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, 2012 and December 31, 2011, were $0 and $0, respectively.

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 18. 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' executive officers 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.

STOCKHOLDER PROPOSALS FOR 2014 ABRAXAS ANNUAL MEETING

Abraxas intends to hold its next annual meeting during the second quarter of 2014, according to its normal schedule. In order to be included in the proxy material for the 2014 Annual Meeting, Abraxas must receive eligible proposals from stockholders intended to be presented at the annual meeting on or before January 14, 2014, 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 2014 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 13, 2014 and the close of business on March 15, 2014. 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 2014 Annual Meeting is more than 30 days from May 14, 2014 (the anniversary of the 2013 Annual Meeting), the dates for submission of proposals to be included in the proxy materials and for business to be properly brought before the 2014 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 Securities and Exchange Commission on Form 10-K, including financial statements and schedules thereto, for the fiscal year ended December 31, 2012. 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 12, 2013

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, 2012

☐ 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, 2012, 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 $274,945,685 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 12, 2013, there were 92,733,448 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2013 Annual Meeting of Stockholders to be held on May 14, 2013.	Part III

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

- the availability of capital;
- the prices we receive for our production and the effectiveness of our hedging activities;
- 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;
- our restrictive debt covenants;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- other factors discussed elsewhere in this report.

GLOSSARY OF TERMS

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

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

Terms used to describe quantities of oil and gas:

"***Bbl***"—barrel or barrels.

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

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

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

"***MBbl***"—thousand barrels.

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

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

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

"***MMBbl***"—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.

"***NGL***"—natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

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

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

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

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

"***Gross acres***" are the number of acres in which we own a working interest.

"***Gross well***" is a well in which we own an interest.

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

"***Net well***" is the sum of fractional ownership working interests in gross wells.

"***Productive well***" is an exploratory or a development well that is not a dry 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***" are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable—from a given date forward, from known reservoirs, and under defined economic conditions, operating methods, and government regulations.

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

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

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

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

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

"***PV-10***" means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission ("SEC").

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

Part I

Information contained in this report represents the operations of Abraxas Petroleum Corporation. The terms "Abraxas," "we," "us," "our," or the "Company," refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Raven Drilling, LLC which is a wholly owned subsidiary that owns a drilling rig.

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, 2012, our estimated net proved reserves were 30.1MMBoe, of which 51% were classified as proved developed, 66% were oil and NGL's and 81% of which (on a PV-10 basis) are operated by us. Our daily net production for the year ended December 31, 2012 was 3,937 Boepd, of which 52.5% 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, 2012:

	Gross Producing Wells	Average Working Interest	Total Net Acres	Estimated Net Proved Reserves		Net Production	
				(MBoe)	% Oil/NGL	(MBoe)	% Oil/NGL
Rocky Mountain	1,065	10.26%	60,016	14,980.4	81.6%	560.0	76.1%
Mid-Continent	147	22.53%	5,820	392.7	37.1%	53.3	16.8%
Permian Basin	220	74.81%	42,093	7,130.1	39.2%	472.1	41.5%
Onshore Gulf Coast	64	87.52%	11,468	7,264.7	63.2%	297.7	29.6%
Total United States	1,496	24.26%	119,397	29,767.9	66.4%	1,383.1	52.0%
Alberta, Canada(1)	8	100.00%	29,440	385.9	53.1%	54.0	64.6%
Total	1,504	24.67%	148,837	30,153.8	66.2%	1,437.1	52.5%

(1) Excludes approximately 22,000 acres subject to a farmout agreement.

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

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

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

Our properties in the onshore Gulf Coast region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas and in the Portilla field in San Patricio County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation at a depth of 14,000 feet and in the Portilla field, our wells produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet. In addition, as the result of the dissolution of Blue Eagle Energy, LLC, or Blue Eagle, a joint venture targeting the Eagle Ford formation in South Texas, we own a 100 percent interest in Yoakum, DeWitt County (1,868 net acres), a 18.75 percent interest in WyCross, McMullen County (1,035 net acres) and a 100 percent interest to the base of the Buda formation in Jourdanton, Atascosa County (4,401 net acres).

Our properties in the province of Alberta, Canada are located in the Pekisko fairway and the Nordegg/Tomahawk area of Central Alberta in addition to the Duvernay Shale in central Alberta.

Strategy

Our business strategy is to focus our capital and resources on our core operated basins, maintain financial flexibility and profitably grow production and reserves. Key elements of our business strategy include:

Focusing our capital and resources on our core operated basins. Our core basins consist of the Williston Basin (Bakken/Three Forks), onshore Gulf Coast (Eagle Ford shale), Permian Basin and Powder River Basin. Given the current disparity between oil and gas prices, the economics of drilling oil wells is currently far superior to drilling gas wells. Thus, 95% of our 2013 estimated capital expenditures will be spent in our two primary oil basins drilling Bakken, Three Forks and Eagle Ford oil wells. The remainder of our capital will be spent drilling two Yates oil wells in the Permian Basin, oil recompletions in the Gulf Coast and one vertical pressure test in the Duvernay shale in the province of Alberta, Canada. Furthermore, as part of our efforts to focus our property portfolio, we are continually marketing assets we have deemed non-core. This includes assets with a low working interest, assets that are non-operated and/or assets that fall outside of our four core basins. Any proceeds from these asset sales will be used to reduce our indebtedness and/or redeployed into our core operating basins.

Maintaining financial flexibility. Our primary sources of capital are availability under our credit facility and cash flow from operations. We seek to reduce the volatility of our cash flow from operations by maintaining a significant hedging profile. We plan on deploying our available capital in a cost-effective manner. For example, we exclusively utilize PAD development drilling with our drilling rig in the Williston Basin. At December 31, 2012 we had approximately $37.0 million of availability under our credit facility and for the year ended December 31, 2012, we generated approximately $51.4 million of cash flow from operations.

Profitably grow production and reserves. We have a substantial low-decline legacy production base as evidenced by our over 21 year reserve life as of year-end 2012. Our capital is currently being deployed largely into unconventional oil assets with relatively predictable production profiles, yet steep initial decline rates. Therefore, the economics of these oil wells are highly dependent on both near term commodity prices and strong operational cost control. Our rig in the Williston Basin, and heightened focus on cost control in all of our operated positions both contribute to our history of adding low cost barrels to our production base. As evidence of production growth not being an objective, but the outcome of sound investment decisions, we achieved 65% liquids growth since the first quarter of 2010 despite relatively stagnant absolute volume growth.

2013 Budget and Drilling Activities

We have a substantial inventory of acreage in several basins, or plays, exposing us to significant resource potential which will be the focus of our development plans in 2013. 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 Turner formation and the Duvernay Shale in Central Alberta. Our acreage in the conventional plays includes the Alberta Basin focused on the Pekisko formation and several oil plays in Texas focused on the Strawn, Frio and Yates formations.

Our capital expenditure budget for 2013 is $70 million. Approximately 68% of the 2013 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks in the Rocky Mountain region, approximately 27% in the Eagle Ford Shale play in South Texas with the remainder targeting conventional oil plays in the Permian Basin region and in the province of Alberta, Canada. The 2013 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

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, 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, our revenue, profitability and cash flow from operations. You should read the discussion under "Risk Factors—Risks Relating to Our Industry—Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies" for more information relating to the effects of decreases in oil and gas prices on us. To help mitigate the impact of commodity price volatility, we hedge a portion of our production through the use of fixed price swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—General—Commodity Prices and Hedging Arrangements" and Note 14 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2012, three purchasers accounted for approximately 39% of our oil and gas sales, and a single purchaser accounted for 16% 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 any 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 exploration while other states/provinces rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, provincial and state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each province and state generally imposes a production or severance tax with respect to the production and sale of oil, gas and NGLs within its jurisdiction.

Operations on Federal, Provincial or Indian oil and gas leases must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies, including the Bureau of Land Management and the

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

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

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

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended, which we refer to as NGA, the Natural Gas Policy Act of 1978, as amended, which we refer to as NGPA, and regulations promulgated thereunder by the Federal Energy Regulatory Commission, which we refer to as FERC, and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended, which we refer to as the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders, which we refer to, collectively, as Order No. 636, to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly 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 penalties for pollution resulting from our operations.

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

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

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

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

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

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

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

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

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

Clean Water Act. The Clean Water Act, which we refer to as the CWA, and analogous state laws, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. 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. In the past few years, EPA has adopted new more restrictive regulations governing air emissions from oil and gas operations, including regulations which impose new restrictions on volatile organic compounds, sulfur dioxide and hazardous air pollutants. Certain of these regulations will become effective in 2015 and will impose new restrictions on air emissions arising from hydraulic fracturing operations.

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

Hydraulic Fracturing. Most of our current operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand, or other proppants, into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate the formation to enhance production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills such as the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act have been introduced in Congress to subject hydraulic fracturing to federal regulation under laws such as the Safe Drinking Water Act. If adopted, these bills could result in additional chemical disclosure and permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, these bills would require the public disclosure of information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. The EPA has finalized its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, which is expected to result in a final report on the subject with recommendations in 2014. Also, the U.S. Department of the Interior has announced that it intends to propose regulations governing hydraulic fracturing which occurs on federal lands, including requiring chemical disclosure. In addition to these federal legislative and regulatory proposals, some states and local governments have considered imposing, or have adopted 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 widely adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells. Some states in which we operate have implemented disclosure requirements for chemicals used in hydraulic fracturing.

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

Although various climate change legislative measures have been under consideration by the U.S. Congress, it is not possible at this time to predict when, or if, Congress will act on climate change legislation, although any major initiatives in this area to be unlikely to become law in the near future due to opposition in the U.S. House of Representatives. 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. Looking forward, we expect more listings of such species to occur, in light of consent decrees involving the U.S. Fish and Wildlife Service which require the agency to decide whether or not to list, as endangered or threatened, approximately 251 candidate species by 2016. Included in this group are a number of terrestrial species, such as the lesser prairie chicken which, if listed, could include habitat in areas where we operate or plan to operate. Such listing of additional species, or the discovery of previously unidentified endangered or threatened species, could cause us to incur additional costs or become subject to operating restrictions, construction delays, or bans on operating in the affected areas.

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

Title to Properties

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

Competition

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

Employees

As of March 12, 2013, we had 101 full-time employees. We retain independent geological, land and engineering consultants from time to time and expect to continue to do so in the future.

Available Information

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

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments filed with the SEC are available free of charge on our web site at www.abraxaspetroleum.com in the Investor Relations section as soon as practicable after such reports are filed. Information on our web site is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

We have substantial indebtedness which may adversely affect our cash flow and business operations.

At December 31, 2012, we had a total of $113.0 million of indebtedness under our credit facility. Our indebtedness could have important consequences to us, including:

- effecting our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes which may be impaired or not available on favorable terms;
- covenants contained in our credit facility and future debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including future business opportunities;
- we may need a substantial portion of our cash flow from operations to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our level of indebtedness will make us more vulnerable to competitive pressures if there is a downturn in our business or the economy in general, than our competitors with less debt.

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

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

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

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

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

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

A breach of any of these covenants could result in a default under our credit facility. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms acceptable or favorable to us. For example, at December 31, 2011 and March 31, 2012, we were not in compliance with the financial ratio that we maintain a current ratio, as of the last day of each quarter, of not less than 1.00 to 1.00. We received waivers from our bank group for this covenant breach. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 “Derivatives and Hedges” and ASC 410-20 “Asset Retirement Obligations”, 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.

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

We have sold producing properties to provide us with liquidity and capital resources in the past and we may continue to do so in the future. After any such sale, we would expect to utilize the proceeds to reduce our indebtedness and to drill new wells on our remaining properties. If we cannot replace the properties sold with production from our remaining properties, our cash flow from operations will likely decrease, which in turn, could 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 could 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, 2012, our average annual estimated decline rate for our net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. As our proved reserves and consequently our production decline, our cash flow from operations, and the amount that we are able to borrow under our credit facility could also decline. In addition, approximately 49% of our total estimated proved reserves at December 31, 2012 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;
- our ability to obtain permits for drilling locations; and
- lease expirations and continuing development obligations.

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

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

Drilling involves numerous risks, including the risk that the new wells we drill will be unproductive or that we will not recover all or any portion of our capital investment. Drilling for oil and gas may be unprofitable. Dry wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. The inherent risk of not finding commercially productive reservoirs is compounded by the fact that 49% of our total estimated proved reserves as of December 31, 2012 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 may decrease.

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

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

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

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

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

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

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

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

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

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

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

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

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- adverse weather conditions;
- title problems;
- unusual or unexpected geological formations;
- fires, blowouts and explosions; and
- uncontrollable flows of oil or gas or well fluids.

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

We do not insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and gas operations.

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

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

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

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

Hydraulic fracturing is the primary completion method used to extract reserves located in many of the unconventional oil and gas plays in the United States and Canada. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and gas production. We use this completion technique on substantially all of our wells. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal, state and/or provincial levels, exploration, exploitation and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Some states in which we operate, including Texas, have recently implemented disclosure requirements of chemicals used in hydraulic fracturing, and the U.S. Department of the Interior has announced that it intends to propose regulations governing hydraulic fracturing on federal lands, including requiring chemical disclosure. Individually or collectively, such existing and new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business, financial condition and results of operations.

Hydraulic fracturing is typically regulated by state oil and gas commissions; however, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Underground Injection Control Program established under the Safe Drinking Water Act, or SDWA, and published draft permitting guidance in May 2012 addressing the performance of such activities. In November 2011, the Environmental Protection Agency, or EPA, announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and the agency currently project to issue an Advance Notice of Proposed Rulemaking in May 2013 that would seek public input on the design and scope of such disclosure regulations. In August 2012, the EPA published final rules under the CAA, which became effective October 15, 2012, that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 or performing reduced emission completions, also known as "green completions," with or without combustion devices, on or after January 1, 2015. In addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development or production activities.

Certain states in which we operate, including Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosures, and well-construction requirements on hydraulic-fracturing operations. For example, Texas adopted a law in June 2011 requiring disclosure to the Texas Railroad Commission and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, in the event state or local restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

Certain governmental reviews were recently conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress released by the agency on December 21, 2012 and a final report expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. See "Item 1. Business—Environmental Matters—Hydraulic Fracturing" above for additional discussion related to environmental risks associated with our hydraulic fracturing activities.

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

The marketability of our production depends in part upon processing and transportation facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by U.S. Federal and state, as well as Canadian provincial, regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If our access to these transportation options dramatically changes, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas.

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

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

During 2012, differentials averaged ($9.05) per Bbl of oil and ($0.47) per Mcf of gas. Approximately 76% of our oil and NGL production during 2012 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 continues to increase, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the realized price we receive could significantly reduce our revenues and our cash flow from operations.

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

To achieve more predictable cash flow and reduce our exposure to adverse fluctuations in the prices of oil and gas, we enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 60% of the oil production from our estimated net proved developed producing reserves (as of December 31, 2012) through December 31, 2013, 80% in 2014, 78% in 2015 and 81% for 2016. 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 opportunity from operations could be adversely affected.

When our derivative contract prices are higher than market prices, we will incur realized and unrealized gains on our derivative contracts and conversely, when our contract prices are lower than market prices, we will incur realized and unrealized losses. For the year ended December 31, 2012, we recognized a realized loss on oil and gas derivative contracts of $0.3 million and an unrealized gain of $2.7 million. The realized loss resulted in a decrease in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility.

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

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

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

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

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

On July 21, 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which imposes a comprehensive regulatory scheme significantly impacting companies engaged in over-the-counter swap transactions. The Dodd-Frank Act generally applies to "swaps" entered into by "major swap participants" and/or "swap dealers," each as defined in the Dodd-Frank Act. A swap is very broadly defined in the Dodd-Frank Act and includes an energy commodity swap. A swap dealer includes an entity that regularly enters into swaps with counterparties as an "ordinary course of business for its own account." Furthermore, a person may qualify as a major swap participant if it maintains a "substantial position" in outstanding swaps, other than swaps used for "hedging or mitigating commercial risk" or whose positions create substantial exposure to its counterparties or the U.S. financial system. The Dodd-Frank Act subjects swap dealers and major swap participants to substantial supervision and regulation by the Commodity Futures Trading Commission, or the CFTC, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. The CFTC recently promulgated regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions would be exempt from these position limits. Position limits for spot month limits became effective on October 12, 2012 while non-spot limits for energy-related commodities are not expected to be effective until mid-to late-2013. The CFTC also has proposed regulations to establish minimum capital and margin requirements, as well as clearing and trade-execution requirements in connection with certain derivative activities, although it's not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under Dodd Frank. In addition, the CFTC's regulations adopted pursuant to the Dodd-Frank Act impose certain record keeping and transactional reporting requirements that may be burdensome and costly to us and to the counterparties to our commodity derivative contracts.

The new legislation and any new regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral or provide other credit support, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the new legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. If the new legislation and regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

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, 2011, the net capitalized cost of our United States and Canadian oil and gas properties did not exceed the present value of our estimated proved reserves. At December 31, 2012, 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 $19.8 million, resulting in a write down of $19.8 million. We had write downs in the second, third and fourth quarters of 2012 of $1.3 million, $11.8 million and $6.7 million respectively.

Use of our net operating loss carryforwards may be limited.

At December 31, 2012, we had, subject to the limitation discussed below, $169.6 million of net operating loss carryforwards for U.S. tax purposes and $15.0 million for Canadian tax purposes. The U.S. loss carryforwards will expire in varying amounts through 2032, and the Canadian carryforward will expire in 2032, 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 ASC 740-10, we have established a valuation allowance of $89.7 million at December 31, 2012.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. In addition, computer technology controls nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced cyber attacks, we may suffer such losses in the future. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber attacks.

We rely on independent experts and technical or operational service providers over whom we may have limited control.

We use independent contractors to provide us with certain technical assistance and services. We rely upon the owners and operators of rigs and drilling equipment, and upon providers of field services, to drill and develop our prospects to production. We also rely upon the services of other third parties to explore and/or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. Our limited control over the activities and business practices of these service providers, any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially adversely affect our business, results of operations and financial condition.

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. Recently low gas prices affected us more than oil prices. 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.

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, 2012 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, 2012. The average realized sales prices as of such date used for purposes of such estimates were $2.61 per Mcf of gas and $88.26 per Bbl of oil. The December 31, 2012 estimates also assume that we will make future capital expenditures of approximately $328.6 million in the aggregate primarily from 2013 through 2017, 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, 2012 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of our reserves set forth or incorporated by reference in this report.

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

As required by SEC regulations, we based the estimated discounted future net cash flows from our proved reserves as of December 31, 2012 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2012 and costs in effect on December 31, 2012, the date of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

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

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

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

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

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.

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and natural gas exploration and production activities in certain U.S. federal income tax incentives and deductions currently available to such companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective and whether such changes may apply retroactively. Although we are unable to predict whether any of these or other proposals will ultimately be enacted, the passage of any legislation as a result of these proposals or any other similar changes to U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available to us, and any such change could negatively affect our financial condition and results of operations.

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 cash distributions.

Shares eligible for future sale may depress our stock price.

At December 31, 2012, we had 92,733,448 shares of common stock outstanding of which 6,417,073 shares were held by affiliates and, in addition, 4,760,910 shares of common stock were subject to outstanding options granted under stock option plans (of which 2,992,467 shares were vested at December 31, 2012).

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

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

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

- fluctuations in commodity prices;
- variations in results of operations;

- legislative or regulatory changes;
- 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, 2012. There are no material lease expirations in 2013.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage(1)		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres(2)
Rocky Mountain	72,194	33,496	85,957	36,396	1,721	851	70,743
Mid-Continent	24,108	5,524	5,878	296	—	—	5,820
Permian Basin	24,408	17,441	21,430	19,379	12,007	5,272	42,092
Onshore Gulf Coast	10,652	6,181	6,824	5,287	—	—	11,468
Total United States	131,362	62,642	120,089	61,358	13,728	6,123	130,123
Alberta, Canada(3)	2,240	2,240	27,200	27,200	—	—	29,440
Total	133,602	64,882	147,289	88,558	13,728	6,123	159,563

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

(2) Includes 3,981 acres in the Permian Basin region that are included in both developed and undeveloped gross acres.

(3) Excludes approximately 22,000 acres subject to a farmout agreement.

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2012:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Rocky Mountain	558.0	93.4	507.0	15.9
Mid-Continent	6.0	3.5	141.0	29.6
Permian Basin	161.0	133.4	59.0	31.2
Onshore Gulf Coast	33.5	33.5	30.5	22.5
Total United States	758.5	263.8	737.5	99.2
Alberta, Canada	8.0	8.0	—	—
Total	766.5	271.8	737.5	99.2

Reserves Information

The estimation and disclosure requirements we employ conform to 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. This 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, 2012, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for Abraxas' properties comprising approximately 99% of the PV-10 of our proved oil and gas reserves. Proved reserves for the remaining 1% of our properties were estimated by Abraxas personnel because we determined that it was not practical for DeGoyler and MacNaughton to prepare reserve estimates for these properties as they are located in a widely dispersed geographic area and have relatively low value. DeGolyer and MacNaughton's reserve report as of December 31, 2012 for Abraxas included a total of 575 properties and our internal report included 409 properties.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists. They do not own an interest in any of our properties and are not employed on a contingent fee basis. All reports by DeGolyer and MacNaughton were developed utilizing their own geological and engineering data, supplemented by data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 26, 2013, 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, 2012 were based on studies performed by the engineering department of Abraxas which is directly responsible for Abraxas' reserve evaluation process. The Vice President of Engineering manages this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and is a Registered Professional Engineer in the State of Texas; he has 34 years of experience in reserve evaluations. The operations department of Abraxas assisted in the process, and consists of three petroleum engineers with Bachelor degrees in Petroleum Engineering, and various other technical professionals. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, include oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages which are obtained from other departments within Abraxas.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations or de-escalations except by contractual arrangements. For the year ended December 31, 2012, commodity prices over the prior 12-month period and year end costs were used in estimating future net cash flows.

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

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2012. All of our reserves are located in the United States (approximately 99%) and Canada.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2012

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil Equivalents (MBoe)
Proved				
Developed	7,331.9	1,318.2	41,220.3	15,520.1
Undeveloped	10,009.8	1,296.5	19,964.0	14,633.7
Total Proved	17,341.7	2,614.7	61,184.3	30,153.8
Probable				
Developed Producing	16.8	4.0	24.3	24.8
Developed Non-producing	66.3	0.7	369.6	128.6
Undeveloped	12,265.2	2,594.8	58,394.4	24,592.5
Total Probable	12,348.3	2,599.5	58,788.3	24,745.9
Possible				
Undeveloped	10,554.9	1,176.8	17,577.6	14,661.3
Total	40,244.9	6,391.0	137,550.2	69,561.0

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2012, 2011, and 2010, and changes in proved reserves during the last three years are presented in the *Supplemental Oil and Gas Disclosures* under Item 8 of this Report. Also presented in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves.

We have not filed information with a federal authority or agency with respect to our estimated total proved reserves at December 31, 2012. We report gross proved reserves of operated properties in the United States to the U.S. Department of Energy on an annual basis; these reported reserves are derived from the same data used to estimate and report proved reserves in this Report.

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 report. We may also adjust estimates of reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. In particular, estimates of oil and gas reserves, future net revenue from reserves and the PV-10 thereof for the oil and gas properties described in this report are based on the assumption that future oil and gas prices remain the same as oil and gas prices utilized in the December 31, 2012 report. The average realized sales prices used for purposes of such estimates were $88.26 per Bbl of oil and $2.61 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $328.6 million in the aggregate primarily in the years 2013 through 2017, which are necessary to develop and realize the value of proved reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

You should not assume that the present value of future net revenues referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves is calculated using the average first-day-of-the-month price over the prior 12-month period. Costs used in the estimated discounted future net cash flows are costs as of the end of the period. Because we use the full cost method to account for our oil and gas operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. This is known as a "ceiling limitation write-down." This charge does not impact cash flow from operating activities but does reduce our stockholders' equity and reported earnings. We have experienced ceiling limitation write-downs in the past and we cannot assure you that we will not experience additional ceiling limitation write-downs in the future. As of December 31, 2012, 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 costs of oil and gas properties in Canada did exceed the present value of our estimated proved reserves by $19.8 million, resulting in a write down for the year ended December 31, 2012.

For more information regarding the full cost method of accounting, you should read the information under "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies."

Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. Our effective interest rate on borrowings at various times and the risks associated with us or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Proved Undeveloped Reserves

Changes in PUDs. Significant changes to PUDs occurring during 2012 are summarized in the table below. Revisions of prior estimates reflect the addition of new PUDs associated with current development plans, revisions to prior PUDs, revisions to infill drilling development plans, as well as the transfer of PUDs to unproved reserve categories due to changes in development plans during the period. Our year-end development plans are consistent with SEC guidelines for PUDs development within five years unless specific circumstances warrant a longer development time horizon.

MMBoe	
PUDs at December 31, 2011	11,376
Revisions of prior estimates	(313)
Extensions, discoveries, and other additions	5,968
Conversion to developed	(1,030)
Sales	(1,368)
PUDs at December 31, 2012	14,633

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.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2011 and 2012:

	December 31,	
(in thousands)	**2011**	**2012**
PV-10	$298,001	$316,862
Present value of future income taxes discounted at 10%	(28,919)	(38,717)
Standardized measure of discounted future net cash flows	$269,082	$278,145

Oil and Gas Production, Sales Prices and Production Costs

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

	2010	2011	2012
Oil production (Bbls)			
Rocky Mountain	286,114	310,819	402,869
Permian Basin	107,763	113,151	113,691
Onshore Gulf Coast	75,571	93,182	86,107
Other[4]	29,260	22,738	40,825
Total	498,708	539,890	643,492
Gas production (Mcf)			
Rocky Mountain	570,736	474,269	802,001
Permian Basin	2,135,918	1,891,333	1,657,165
Onshore Gulf Coast	1,757,901	1,482,260	1,257,124
Other[4]	1,014,347	373,970	380,789
Total	5,478,902	4,221,832	4,097,079
NGL production (Bbls)			
Rocky Mountain	4,228	11,451	23,468
Permian Basin	278	15,171	82,200
Onshore Gulf Coast	79	231	2,036
Other[4]	5,624	1,271	3,047
Total	10,209	28,124	110,751
Total production (MBoe)[1]	1,422	1,272	1,437
Average sales price per Bbl of oil[2]			
Rocky Mountain	$ 68.79	$ 85.73	$ 81.61
Permian Basin	$ 75.94	$ 91.07	$ 87.97
Onshore Gulf Coast	$ 77.32	$ 97.09	$ 100.31
Other[4]	$ 76.13	$ 91.62	$ 79.66
Composite	$ 71.37	$ 89.06	$ 85.11
Average sales price per Mcf of gas[2]			
Rocky Mountain	$ 4.28	$ 3.77	$ 2.71
Permian Basin	$ 4.00	$ 3.81	$ 2.45
Onshore Gulf Coast	$ 3.62	$ 3.31	$ 2.14
Other[4]	$ 4.32	$ 3.28	$ 2.00
Composite	$ 3.97	$ 3.58	$ 2.36
Average sales price per Bbl of NGL			
Rocky Mountain	$ 42.03	$ 49.71	$ 37.27
Permian Basin	$ 34.48	$ 48.27	$ 35.45
Onshore Gulf Coast	$ 38.03	$ 45.75	$ 27.52
Other[4]	$ 34.79	$ 75.69	$ 67.28
Composite	$ 37.81	$ 50.08	$ 36.57
Average sales price per Boe[2]	$ 40.82	$ 50.81	$ 47.67
Average cost of production per Boe produced[3]			
Rocky Mountain	$ 17.34	$ 19.58	$ 17.41
Permian Basin	$ 11.88	$ 13.16	$ 13.11
Onshore Gulf Coast	$ 6.06	$ 7.81	$ 8.55
Other[4]	$ 9.36	$ 16.89	$ 18.90
Composite	$ 13.81	$ 16.94	$ 14.27

(1) Oil and gas were combined by converting gas to a Boe equivalent on the basis of 6 Mcf of gas to 1 Bbl of oil.
(2) Before the impact of hedging activities.
(3) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.
(4) Includes Canada and Mid-Continent comprising approximately 7.5% of total production.

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[1]		2011[2]		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Rocky Mountain	1.0	1.0	2.0	1.1	—	—
Permian Basin	1.0	0.4	1.0	1.0	—	—
Onshore Gulf Coast	—	—	—	—	—	—
Other[3]	—	—	—	—	—	—
Total	2.0	1.4	3.0	2.1	—	—
Dry wells						
Permian Basin	—	—	1.0	1.0	—	—
Onshore Gulf Coast	1.0	1.0	—	—	—	—
Total	1.0	1.0	1.0	1.0	—	—
Development						
Productive						
Rocky Mountain	16.0	1.8	12.0	1.2	22.0	2.6
Permian Basin	2.0	2.0	2.0	2.0	1.0	1.0
Onshore Gulf Coast	3.0	3.0	7.0	7.0	2.0	0.5
Other[3]	3.0	2.0	4.0	4.0	—	—
Total	24.0	8.8	25.0	14.2	25.0	4.1

(1) Excludes 1.0 gross (1.0 net) well drilled by Blue Eagle.
(2) Excludes 2.0 gross (1.4 net) wells drilled by Blue Eagle.
(3) Includes drilling activities in Canada and Mid-Continent.

In addition to the above drilling activity, as of December 31, 2012 we had 16.0 gross (2.96 net) wells that were at various stages of drilling and/or completion.

Present Activities

As of March 12, 2013, we had eight gross operated wells and five gross non-operated wells in the process of drilling and/or completing. The following provides an overview of our present activities by region:

Rocky Mountain—North Dakota / Montana

- In the Bakken/Three Forks play in the Williston Basin, in the fourth quarter of 2012 we completed the drilling of our first multi-well pad with our Company owned drilling rig. The Jore Federal 02-11 3H was the first completion off this pad and was turned to sales in October 2012. We own a 76% working interest in the Jore Federal 02-11 3H. Two additional wells on this pad, the Ravin 26-35 2H and Ravin 26-35 3H, suffered third party equipment failures during the completion process. Post remediation, the Ravin 26-35 2H and Ravin 26-35 3H were completed and turned to sales in February 2013.
- In October 2012, we mobilized our Company owned rig to the Lillibridge East pad to commence a four well drilling program. Surface and intermediate casing have been set on all four Lillibridge wells. We also drilled and cased the lateral on the Lillibridge 20-17 4H. The rig is currently mobilizing to drill the lateral of the Lillibridge 20-17 3H, which will be followed by laterals of the Lillibridge 20-17 2H and Lillibridge 20-17 1H. We own an approximate 34% working interest across all four wells on the Lillibridge East pad.
- In the non-operated portion of the Company's Bakken/Three Forks position in the Williston Basin, we have participated in 15 gross (.8 net) non-operated wells since the fourth quarter of 2012.

South Texas—Eagle Ford

- In the WyCross area of McMullen County, Texas, we drilled and completed two gross (.44 net) wells targeting the Eagle Ford Shale during the fourth quarter of 2012. Subsequent to the fourth quarter of 2012, we drilled and completed an additional two gross (.44 net) wells. Our sixth well at WyCross, the Mustang 3H is currently in the latter stages of completion. Abraxas owns an approximate 18.75% working interest in the Mustang 3H. The Company recently reached total depth on our seventh well at WyCross, the Mustang 2H, in which we hold an 18.75% working interest. We anticipate maintaining a one rig program at WyCross throughout 2013.

Permian Basin

- In Ward County, Texas, we recently drilled and cased two gross (two net) shallow Yates wells, the Wilkes No.1 and Wilkes No.2, since the fourth quarter of 2012. Early logs on these wells have been encouraging and we expect to complete these wells in the near future.

Canada—Duvernay Shale

- In the Eastern Shale Basin of Alberta Canada, since the fourth quarter of 2012, we entered into a farmout option arrangement with a large independent whereby we have the option to earn up to approximately 22,000 acres of land targeting the Duvernay Shale upon satisfying various drilling commitments. This farmout arrangement is incremental to our established 20,000 net acre position in the play. We recently drilled, cored and cased a vertical well to analyze the rock properties and determine the pressure regime of the Duvernay Shale in the Eastern Shale Basin. The core from this well is currently under evaluation at a laboratory in Calgary, Alberta, Canada.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist of approximately 21,000 square feet. We own the building which is subject to a real estate lien note. The note bears interest at a fixed rate of 5.25%, and is payable in monthly installments of principal and interest of $36,652 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2012, $4.8 million was outstanding on the note. We lease office space in Calgary, Alberta for a monthly rental of $3,836 CN. The lease expires on January 31, 2014. We lease office space in Dickinson, North Dakota for a monthly rental of $2,170. The lease expires on August 31, 2013.

Other Properties

We own 1,769 acres of land, including an office building, workshop, warehouse and house in San Patricio County, Texas, 613 acres of land and an office building in Scurry County, Texas, 50 acres of land in DeWitt County, Texas, 162 acres of land in Coke County, Texas, 582 acres of land in McKenzie County, North Dakota and 12,817 acres of land in Pecos County, Texas.

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

Item 3. Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2012, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

Item 4. Mine Safety Disclosures

Not applicable

Part II

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

Market Information

Our common stock is traded on The NASDAQ Stock Market under the symbol "AXAS." The following table sets forth certain information as to the high and low sales price quoted for our common stock.

Period	High	Low
2011		
First Quarter	$6.16	$4.06
Second Quarter	5.97	3.01
Third Quarter	5.18	2.50
Fourth Quarter	4.45	1.86
2012		
First Quarter	$4.39	$3.03
Second Quarter	3.45	2.49
Third Quarter	3.38	1.91
Fourth Quarter	2.42	1.56
2013 First Quarter (Through March 12, 2013)	$2.37	$1.93

Holders

As of March 12, 2013, we had 92,733,448 shares of common stock outstanding and approximately 1,146 stockholders of record.

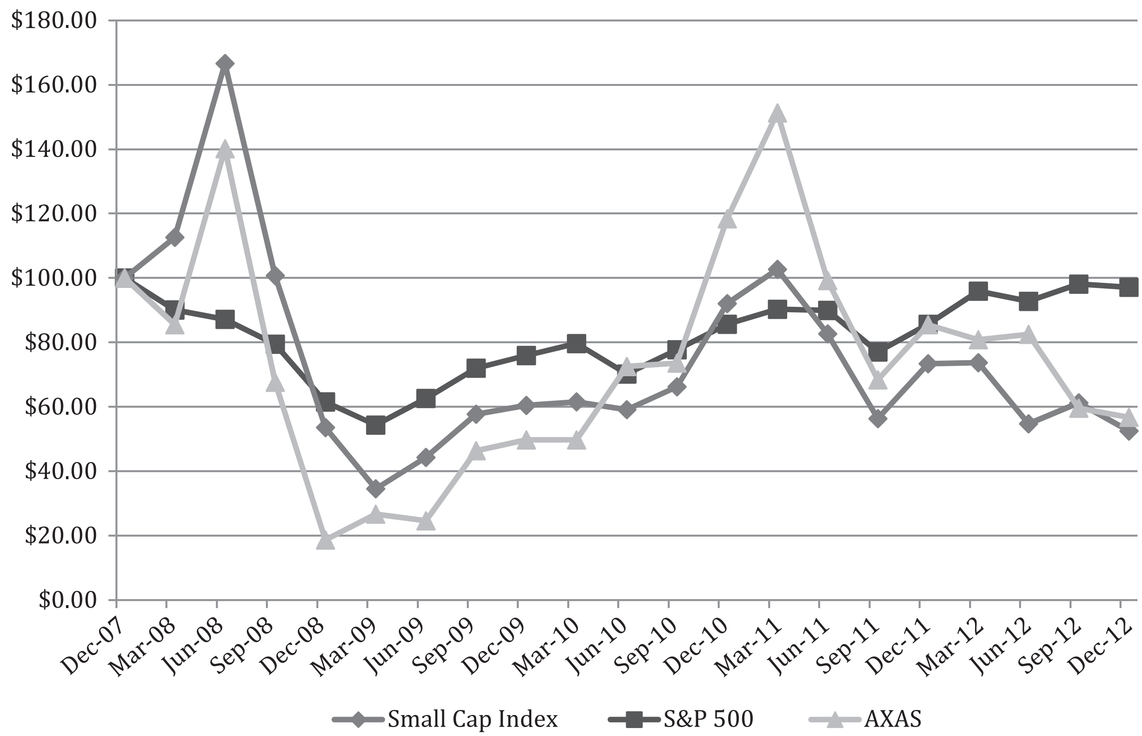
Dividends

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) a market capitalization weighted Small Cap Index of onshore, North American ("NAM") focused, U.S. listed, oil and gas exploration and production companies with a market capitalization of less than $1.0 billion as of December 31, 2012 (the "Comparable Companies"). The Comparable Companies are: Approach Resources, Inc. (AREX), Bill Barrett Corp. (BBG), Callon Petroleum Co. (CPE), Carrizo Oil & Gas Inc. (CRZO), Clayton Williams Energy, Inc. (CWEI), Comstock Resources Inc (CRK), Crimson Exploration Inc. (CXPO), Double Eagle Petroleum Co. (DBLE), Emerald Oil, Inc. (EOX), Enerjex Resources, Inc. (ENRJ), Evolution Petroleum Corp. (EPM), Forest Oil Corporation (FST), Gasco Energy Inc. (GSX), Gastar Exploration, Ltd. (GST), GMX Resources Inc. (GMXR), Goodrich Petroleum Corp. (GDP), Magnum Hunter Resources Corp. (MHR), Northern Oil and Gas, Inc. (NOG), Panhandle Oil and Gas Inc. (PHX), PDC Energy, Inc (PDCE), Penn Virginia Corporation (PVA), PetroQuest Energy Inc. (PQ), Quicksilver Resources, Inc. (KWK), Rex Energy Corporation (REXX), Swift Energy Co. (SFY), Triangle Petroleum Corporation (TPLM), US Energy Corp. (USEG), Warren Resources Inc. (WRES) and ZaZa Energy Corporation (ZAZA).

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, 2007, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2008, 2009, 2010, 2011 and 2012.



	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012
S&P 500	$100.00	$61.51	$75.94	$ 85.65	$85.65	$97.13
Small Cap Index	$100.00	$53.57	$60.44	$ 92.07	$73.39	$52.50
AXAS	$100.00	$18.65	$49.74	$118.39	$85.49	$56.74

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

Item 6. Selected Financial Data

The following selected financial data is derived from our Consolidated Financial Statements as of and for the years ended December 31, 2008 through 2012. 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,				
	2008	2009	2010	2011	2012
	(In thousands, except per share data)				
Total revenue	$ 99,100	$ 51,836	$ 58,060	$ 64,622	$ 68,573
Net income (loss)	$ (52,403)[(1)]	$ (18,780)	$ 1,766[(2)]	$ 13,743	$ (18,791)[(3)]
Net income (loss) per common share—diluted	$ (1.07)	$ (0.34)	$ 0.02	$ 0.15	$ (0.20)
Weighted average shares outstanding—diluted	49,005	55,499	77,224	92,244	91,914
Total assets	$211,839	$176,236	$182,909	$241,150	$240,607
Long-term debt, excluding current maturities	$130,835	$143,592	$140,940	$126,258	$124,101
Total stockholders' equity (deficit)	$ 4,658	$ (18,363)	$ (14,976)	$ 62,651	$ 46,700

(1) Includes proved property impairment of $116.4 million.
(2) Includes proved property impairment of $4.8 million related to our Canadian properties.
(3) Includes proved property impairment of $19.8 million related to our Canadian properties.

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

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion excludes the operations of Blue Eagle, except our equity share of Blue Eagle's income (loss). The Blue Eagle joint venture was dissolved effective August 31, 2012. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See "Financial Statements and Supplementary Data" in Item 8.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States and Canada. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

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

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in 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.

The prices of oil and gas have been volatile. During 2012, the price of oil decreased from the levels experienced in 2011. The New York Mercantile Exchange (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $94.16 per barrel in 2012 as compared to $96.19 per barrel in 2011. During 2012, the average price of gas decreased from an average NYMEX Henry Hub spot price of $4.16 per MMBtu in 2011 to $2.83 per MMBtu in 2012. Prices closed on December 31, 2012 at $91.82 per Bbl of oil and $3.43 per MMBtu of gas. If commodity prices decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If gas prices remain depressed or oil prices decline significantly, our revenues, profitability and cash flow from operations may decrease which could cause us to alter our business plans, including reducing our drilling activities.

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

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

The following table sets forth our average differentials for the years ended December 31, 2010, 2011 and 2012:

	Oil			Gas		
	2010	2011	2012	2010	2011	2012
Average realized price	$71.37	$89.06	$85.11	$ 3.97	$ 3.58	$ 2.36
Average NYMEX price	$79.51	$95.06	$94.16	$ 4.38	$ 4.14	$ 2.83
Differential	$ (8.14)	$ (6.00)	$ (9.05)	$(0.41)	$(0.56)	$(0.47)

Our hedging arrangements equate to approximately 60% of the estimated oil production from our net proved developed producing reserves (as of December 31, 2012) through December 31, 2013, 80% in 2014, 78% in 2016 and 81% for 2016. 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 in the past and will in the future 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 2011, we incurred a realized gain of $1.7 million and an unrealized gain of $5.7 million. In 2012, we incurred a realized loss of $0.3 million and an unrealized gain of $2.7 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth the summary position of our derivative contracts at December 31, 2012:

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2013	1,341	$86.70
2014	1,100	$92.58
2015	933	$85.00
2016	883	$84.00

At December 31, 2012, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $6.4 million.

On March 12, 2012, we monetized our gas derivative contracts for $12.4 million.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve estimates as of December 31, 2012, our average annual estimated decline rate for net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and 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 2012 of $68.6 million related to our exploration and development activities. We have a capital expenditure budget for 2013 of $70 million. Approximately 68% of the 2013 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region, approximately 27% in the Eagle Ford Shale play in South Texas with the remainder targeting conventional oil plays in the Permian Basin region and in the province of Alberta, Canada. The 2013 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, 2010, 2011 and 2012:

	Year Ended December 31,		
	2010	2011	2012
Total production (MBoe)	1,422	1,272	1,437
Average daily production (Boepd)	3,896	3,484	3,926
% Oil/ NGL	36%	45%	52%

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, monetizing of derivative instruments, 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, 2012, we had approximately $37.0 million of availability under our credit facility.

Borrowings and Interest. At December 31, 2012, we had a total of $113.0 million outstanding under our credit facility. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices. In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR-based debt. The two-year interest rate swap for $100 million at a fixed rate of 3.367% originally expired on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009, lowering our fixed rate to 2.55% and extending the term through August 12, 2012. The interest rate swap expired in August 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, 2012, we operated properties accounting for approximately 81% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2012, we drilled or participated in 146 gross (41.29 net) wells of which 99% were commercially productive.

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 may also decline. In addition, approximately 49% of our estimated proved reserves at December 31, 2012 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.

	Year Ended December 31, (In thousands, except per unit data) 2010	2011	2012
Operating revenue[1]:			
Oil sales	$ 35,935	$ 48,080	$ 54,770
Gas sales	21,729	15,127	9,679
NGL sales	386	1,408	4,050
Total operating revenues	$ 58,050	$ 64,615	$ 68,499
Operating income (loss)[2]	$ 2,807	$ 11,648	$(16,348)
Oil sales (MBbls)	498.7	539.9	643.5
Gas sales (MMcf)	5,478.9	4,221.8	4,097.1
NGL sales (MBbls)	10.2	28.1	110.8
Oil equivalents (MBoe)	1,422.1	1,271.6	1,437.1
Average oil sales price (per Bbl)[1]	$ 71.37	$ 89.05	$ 85.11
Average gas sales price (per Mcf)[1]	$ 3.97	$ 3.58	$ 2.36
Average NGL sales price (per Bbl)	$ 37.81	$ 50.07	$ 36.57
Average oil equivalent sales price (Boe)	$ 40.82	$ 50.81	$ 47.67

(1) Revenue and average sales prices are before the impact of hedging activities.

(2) Operating income includes a proved property impairment of $4.8 million and $19.8 million in 2010 and 2012, respectively related to our Canadian properties.

Comparison of Year Ended December 31, 2012 to Year Ended December 31, 2011

Operating Revenue. During the year ended December 31, 2012, operating revenue increased to $68.5 million from $64.6 million in 2011. The increase in revenue was due to higher oil and NGL sales volumes in 2012 as compared to 2011, which were partially offset by lower gas sales volumes and lower realized commodity prices. Overall BOE sales in 2012 increased approximately 12% as compared to 2011. Increased oil and NGL sales volumes contributed $11.8 million to operating revenue while decreased gas sales volumes had a negative impact of $0.3 million. Lower commodity prices had a negative impact on operating revenue of $7.7 million.

Oil sales volumes increased to 643.5 MBbls for the year ended December 31, 2012 from 539.9 MBbls for the same period of 2011. The increase in oil sales volumes was due to new production brought on line in 2012. New wells brought onto production in 2012 contributed 129.2 MBbls to production for the year ended December 31, 2012, offset by natural field declines. Gas sales volumes decreased to 4,097.1 MMcf for the year ended December 31 2012 from 4,221.8 MMcf for the year ended December 31, 2011. The decrease in gas production was due to natural field declines and the timing of new wells being brought on line, as well as our emphasis on drilling oil wells as opposed to gas wells. New wells brought onto production during 2012 contributed 361.7 MMcf to production for the year ended December 31, 2012. Due to weak gas prices, our focus was primarily on oil projects during 2012. NGL sales increased to 110.8 MBbls for the year ended December 31, 2012 from 28.1 MBbls for the same period of 2011. The increase in NGL sales was primarily due to increased gas production in West Texas, Wyoming and North Dakota that has a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the year ended December 31, 2012 increased to $24.8 million from $21.6 million in 2011. The increase in LOE was primarily due to increased cost of services, and significant non-recurring LOE related to our Canadian operations. LOE per Boe for the year ended December 31, 2012 was $17.26 compared to $16.97 for the same period of 2011. The increase in LOE per Boe was attributable to higher LOE in 2012, partially offset by higher sales volumes in 2012 as compared to 2011.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2012 increased to $6.6 million from $5.8 million in 2011. The increase was primarily due to increased production, particularly in the Rocky Mountain region where production tax rates are higher. Production and ad valorem taxes as a percentage of oil and gas revenue increased to 10% for the year ended December 31, 2012 from 9% in 2011.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased to $8.6 million for the year ended December 31, 2012 from $7.4 million in 2011. The increase in G&A expense was primarily related to higher salaries and bonuses paid in 2012. G&A expense per Boe was $6.00 for the year ended December 31, 2012 compared to $5.85 for the same period of 2011. The increase in G&A expense per Boe was primarily due to higher production volumes in 2012 compared to 2011.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation for the year ended December 31, 2012 increased to $2.1 million from $2.0 million in 2011. The increase in 2012 as compared to 2011 was due to higher values of grants made during 2012 as compared to 2011, and to additional grants during the third quarter of 2012.

Depreciation, Depletion, and Amortization ("DD&A") Expenses. DD&A expense increased to $23.0 million for the year ended December 31, 2012 from $16.2 million in 2011. Our DD&A rate increased due to higher future development cost in the 2012 year end reserve report. DD&A per Boe for 2012 was $16.02 compared to $12.73 in 2011. The increase in DD&A per BOE was due to higher future development cost offset by higher sales volumes in 2012 as compared to 2011.

Interest Expense. Interest expense increased to $5.5 million in 2012 from $4.9 million for 2011. The increase was primarily due to higher levels of debt during 2012 as compared to 2011

Income Taxes. An income tax expense of $0.3 million was recognized in 2012 as a result of an ongoing audit of our 2009 Federal income tax return. We do not agree with the findings of the audit and it is currently under appeal.

Loss (Gain) on Derivative Contracts. 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. We have elected not to apply hedge accounting to our derivative contracts as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The net estimated value of our commodity derivative contracts was a liability of approximately $6.4 million as of December 31, 2012. 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, 2012, we realized a loss on our derivative contracts of approximately $0.5 million, which included a realized loss of approximately $0.3 million on our commodity swaps and a realized loss of approximately $0.2 million on our interest rate swap. For the year-ended December 31, 2012, we incurred an unrealized gain of $2.7 million on our commodity swaps. We monetized our gas derivative contracts in March 2012 for $12.4 million. Our interest rate swap expired in August 2012. The estimated value of our derivative contracts was an asset of approximately $1.9 million as of December 31, 2011. For the year ended December 31, 2011, we realized a loss on our derivative contracts of approximately $0.7 million, which included a realized gain of $1.7 million on our commodity swaps and a realized loss of $2.4 million on our interest rate swap. For the year-ended December 31, 2011, we incurred an unrealized gain of $7.5 million on our derivative contracts, which included an unrealized gain of $5.7 million on our commodity swaps and $1.8 million on our interest rate swap.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of December 31, 2012, the net capitalized cost of our oil and gas properties in the United States did not exceed the present value of our estimated proved reserves, however in Canada, the net capitalized cost exceeded the present value of our estimated proved reserves by $19.8 million, resulting in a write down of $19.8 million. There were write downs in the second, third and fourth quarters of 2012 of $1.3 million, $11.8 million and $6.7 million respectively. The year-end amount was calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2012 which were $95.14 per Bbl for oil and $2.86 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

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

Equity in (Income) Loss of Joint Venture. We accounted for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in *"Investment in joint venture"* and is also recorded as equity investment income (loss) in *"Equity in loss (income) of joint venture."* For the year ended December 31, 2011, our net share of the joint venture's income was $2.2 million. The joint venture was dissolved on September 4, 2012, effective August 31, 2012, with the assets being distributed to the joint venture partners. The dissolution of the joint venture was accounted for with the net investment in the joint venture being added to our full cost pool. For the year ended December 31, 2012 (through August 31, 2012), we reported income of $2.2 million related to Blue Eagle. See Note 2 of the Notes to Consolidated Financial Statements.

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

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

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

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

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

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

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation for the year ended December 31, 2011 increased to $2.0 million from $1.6 million in 2010. The increase in 2011 as compared to 2010 was due to higher values of grants made during 2011 as compared to 2010, and to additional grants during the third quarter of 2011.

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

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

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

Loss (Gain) on Derivative Contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The net estimated value of our commodity and interest rate derivative contracts was an asset of approximately $1.9 million as of December 31, 2011. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2011, we realized a loss on our derivative contracts of $0.7 million, which included a realized gain of $1.7 million on our commodity swaps and a realized loss of $2.4 million on our interest rate swap. For the year-ended December 31, 2011, we incurred an unrealized gain of $7.5 million on our derivative contracts, which included an unrealized gain of approximately $5.7 million on our commodity swaps and $1.8 million on our interest rate swap. The estimated value of our derivative contracts was a liability of approximately $5.8 million as of December 31, 2010. For the year ended December 31, 2010, we realized a gain on our derivative contracts of approximately $0.5 million, which included a realized gain of $2.8 million on our commodity swaps and a realized loss of $2.3 million on our interest rate swap. For the year-ended December 31, 2010, we incurred an unrealized gain of $10.3 million on our derivative contracts, which included an unrealized gain of $11.4 million on our commodity swaps and an unrealized loss of $1.1 million on our interest rate swap.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of December 31, 2010, the net capitalized cost of our oil and gas properties in the United States did not exceed the present value of our estimated proved reserves, however, the net capitalized cost of our Canadian properties exceeded the present value of our estimated proved reserves by $4.8 million, resulting in a write down of $4.8 million. These amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2010 which were $79.43 per Bbl for oil and $4.45 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

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

Equity in (Income) Loss of Joint Venture. We accounted for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in *"Investment in joint venture"* and was also recorded as equity investment income (loss) in *"Equity in loss (income) of joint venture."* For the year ended December 31, 2011, our net share of the joint venture's income was $2.2 million. For the year ended December 31, 2010, our net share of the joint venture's loss was approximately $0.5 million.

Liquidity and Capital Resources

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

- the development and exploration 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, 2012, our current liabilities of $54.5 million exceeded our current assets of $23.0 million resulting in a working capital deficit of $31.5 million. This compares to a working capital deficit of $14.8 million at December 31, 2011. Current assets at December 31, 2012 primarily consist of cash of $2.1 million, and accounts receivable of $20.4 million. Current liabilities at December 31, 2012 primarily consist of trade payables of $42.4 million, revenues due third parties of $6.9 million and the current portion of derivative liabilities of $3.5 million.

Capital Expenditures. Capital expenditures in 2010, 2011 and 2012 were $36.4 million, $79.0 million and $68.6 million, respectively. The table below sets forth the components of these capital expenditures:

	Year Ended December 31,		
	2010	2011	2012
	(In thousands)		
Expenditure category:			
Acquisition of producing properties	$ —	$ —	$ 7,200
Exploration/Development	36,172	56,245	57,307
Facilities and other	276	22,767	4,045
Total	$36,448	$79,012	$68,552

During 2010 capital expenditures were primarily for the development of our existing properties. During 2011, capital expenditures were for the development of our existing properties, the purchase and refurbishment of a drilling rig, and the purchase of 1,769 acres of land (surface only) in our Portilla field in San Patricio County, Texas. During 2012 our expenditures were primarily for development of our existing properties, the acquisition of producing properties in West Texas and the completion of the refurbishment of our drilling rig.

We anticipate making capital expenditures in 2013 of $70.0 million. The 2013 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, and our ability to obtain permits for drilling locations. 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. 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,		
	2010	2011	2012
		(In thousands)	
Net cash provided by operating activities	$ 24,102	$ 24,495	$ 51,375
Net cash used in investing activities	(15,048)	(70,555)	(47,003)
Net cash (used in) provided by financing activities	(10,816)	45,966	(2,311)
Total	$ (1,762)	$ (94)	$ 2,061

Operating activities for the year ended December 31, 2012 provided $51.4 million in cash. Non-cash expense items, net changes in operating assets and liabilities, including the non-cash property impairment of $19.8 million, and the monetization of our gas derivatives accounted for most of these funds. Investing activities used $47.0 million, primarily for the development of our oil and gas properties, acquisition of producing properties, and the completion of the refurbishment of our drilling rig offset by the sale of producing properties. Financing activities used $2.3 million primarily for the reduction of long-term debt.

Operating activities for the year ended December 31, 2011 provided $24.5 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Financing activities provided $46.0 million for the year ended December 31, 2011 which was primarily from the net proceeds from our equity offering in February 2011 of $62.3 million offset by a net reduction in our long term debt. Investing activities used $70.6 million in 2011 for the development of our oil and gas properties, the purchase and reconditioning of a drilling rig and the purchase of 1,769 acres of land (surface only) in our Portilla field in San Patricio County, Texas.

Operating activities for the year ended December 31, 2010 provided $24.1 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds, including the non-cash property impairment of $4.8 million. Financing activities used $10.8 million for the year ended December 31, 2010 which was predominately the reduction of long-term debt. Investing activities used $15.0 million in 2010 for the development of our oil and gas properties, net of proceeds from sale of properties of $21.4 million.

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

Cash from operating activities is dependent upon commodity prices and production volumes. 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. 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, 2012 were classified as undeveloped.

We have in the past, and may in the future, sell producing properties. Most recently, in the third quarter of 2012, we sold certain non-core assets for combined net proceeds of approximately $21.5 million. The net proceeds were used to repay outstanding indebtedness under our credit facility and general corporate purposes.

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

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, 2012:

Contractual Obligations (In thousands)	Payments due in twelve month periods ending:				
	Total	**December 31, 2013**	**December 31, 2014-2015**	**December 31, 2016-2017**	**Thereafter**
Long-term debt[1]	$124,758	$ 657	$121,481	$2,620	$—
Interest on long-term debt[2]	1,340	545	720	75	—
Lease obligations[3]	67	63	4	—	—
Total	$126,165	$1,265	$122,205	$2,695	$—

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These payments assume that we will not borrow additional funds.

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

(3) Lease on office space in Calgary, Alberta, which expires on January 31, 2014 and office space in Dickinson, North Dakota, which expires on August 31, 2013.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2012, our reserve for these obligations totaled $11.4 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2012, 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, 2012, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

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

Long-Term Indebtedness.

Long-term debt consisted of the following:

	December 31, 2011	**December 31, 2012**
	(In thousands)	
Credit facility	$115,000	$113,000
Rig loan agreement	6,500	7,000
Real estate lien note	4,939	4,758
	126,439	124,758
Less current maturities	(181)	(657)
	$126,258	$124,101

Credit Facility

We have a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of December 31, 2012, $113.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At December 31, 2012 we had a borrowing base of $150.0 million. This amount will remain in effect until the next redetermination of the borrowing base which is scheduled to be completed in April 2013. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our Proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base was increased to $150.0 million based upon our reserve report dated June 30, 2012 and did not include any of the properties held for sale. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At December 31, 2012, the interest rate on the credit facility was 3.21% based on 1-month LIBOR borrowings and level of utilization.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

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

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 of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 4.00 to 1.00 and liquidity (defined as the sum of our borrowing base availability, liquid investments and unrestricted cash) of at least $7.5 million for each fiscal quarter ending on or after June 30, 2012 and on or before March 31, 2013. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and 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. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements.

As of December 31, 2012, the interest coverage ratio was 7.72 to 1.00, the total debt to EBITDAX ratio was 2.97 to 1.00, our current ratio was 1.19 to 1.00 and we had liquidity of $39.1 million of which $37.0 was availability under the credit facility. At December 31, 2012, we were in compliance with all of our debt covenants.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

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

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

Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2000 HP diesel electric drilling rig (the "Collateral"). The rig loan agreement provided for interim borrowings payable to Raven Drilling until the final amount of the loan was determined.

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

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

Real Estate Lien Note

On May 9, 2008, the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as its corporate headquarters. This note was refinanced in November 2008. The note bears interest at a fixed rate of 5.25% and is payable in monthly installments of principal and interest of $36,652 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2012, $4.8 million was outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. We have entered into commodity swaps on approximately 60% of our estimated oil production from our net proved developed producing reserves (as of December 31, 2012) through December 31, 2013, 80% for 2014, 78% for 2015 and 81% for 2016.

The following table sets forth the summary position of our derivative contracts as of December 31, 2012:

	Oil	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
2013	1,341	$86.70
2014	1,100	$92.58
2015	933	$85.00
2016	883	$84.00

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, 2012, we incurred a realized loss of $0.3 million and an unrealized gain of $2.7 million on our commodity derivative contracts. For the year ended December 31, 2011, we incurred a realized gain of $1.7 million and an unrealized gain of $5.7 million on our commodity derivative contracts. For the year ended December 31, 2010, we incurred a realized gain of $2.8 million and an unrealized gain of $11.4 million on our commodity derivative contracts. 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.

On March 12, 2012, we monetized our gas derivative contracts for $12.4 million.

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

Net Operating Loss Carryforwards

At December 31, 2012, we had, subject to the limitation discussed below, $169.6 million of net operating loss carryforwards for U.S. tax purposes and $15.0 million for Canadian tax purposes. The U.S. loss carryforwards will expire through 2032 and the Canadian carryforward will expire in 2032, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10 "Income Taxes". Therefore, we have established a valuation allowance of $89.7 million for deferred tax assets at December 31, 2012.

We account for uncertain tax positions under provisions of ASC 740-10. ASC 740-10 did not have any effect on the Company's financial position or results of operations for the year ended December 31, 2011 or for the year ended December 31, 2012. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2012, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly owned subsidiary of Abraxas, have undergone an audit of their 2009 Federal income tax returns. The audit of the Federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of proposed adjustment of $619,000. The Company does not agree with the findings and intends to aggressively appeal the proposed adjustment; however, no assurances can be made that such appeals will be successful. For the year ended December 31, 2012, the Company accrued $310,000 in income tax expense related to the recent audit of its 2009 Federal tax return. This amount was determined by an analysis of what the amount that is greater than 50% likely to be paid upon final settlement.

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. During 2012, we purchased equipment from an officer of our wholly-owned subsidiary Raven Drilling, LLC for total consideration of $195,000. The purchase price was based on an appraisal and was at fair market value. The transaction was approved by the 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 U.S. generally accepted accounting principles ("GAAP") requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

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

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years, most recently in the current year 2012, 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, less related deferred taxes, may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves on a pool by pool basis, discounted at 10%, plus the lower of cost or fair market value of unproved properties and the cost of properties not being amortized, less income taxes. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are depressed. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

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

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

Our proved reserve information included in this report was based on studies performed by our independent petroleum engineers assisted by the engineering and operations departments of Abraxas. Reserve estimates were made by our 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, 2010, 2011 and 2012, oil and gas prices were based on the average 12-month first-day-of-the-month pricing as compared to end of period prices utilized in prior years. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Asset Retirement Obligations. The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense.

Accounting for Derivatives. 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. We have elected not to apply hedge accounting to our derivative contracts as prescribed by ASC 815; as a result, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. Due to the volatility of oil and gas prices and, to a lesser extent, interest rates, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2011 and 2012, the net market value of our commodity derivatives was a net asset of $3.4 million and a net liability of $6.4 million, respectively. The market value of our interest rate derivative was a liability of $3.3 million at December 31, 2011. Our interest rate derivative expired in August 2012.

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 6 to the consolidated financial statements. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date and expense is recognized over the vesting period. For the years ended December 31, 2010, 2011 and 2012, stock-based compensation was approximately $1.6 million, $2.0 million, and $2.1 million, respectively.

Equity Method Investment. Our investment in an unconsolidated joint venture, in which we did not have a majority interest, was accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from our equity investment was reflected as an increase (decrease) in our investment account "Investment in joint venture" and was also recorded as "Equity in loss (income) of joint venture" in "Other (income) expense." The joint venture was dissolved effective August 31, 2012.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indices fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2012, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flow by approximately $6.8 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. We have elected not to apply hedge accounting to our derivative contracts as prescribed by ASC 815; as a result, fluctuations in the market value of the derivative contract are recognized in earnings during the current period.

The following table sets forth the summary position of our derivative contracts as of December 31, 2012:

	Oil	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
2013	1,341	$86.70
2014	1,100	$92.58
2015	933	$85.00
2016	883	$84.00

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. The interest rate swap expired in August 2012.

At December 31, 2012, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $6.4 million.

For the year ended December 31, 2012, we recognized a realized loss of $0.3 million and an unrealized gain of $2.7 million on our commodity derivative contracts and we recognized a realized loss of $0.2 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, 2012, we had $113.0 million of outstanding indebtedness under our credit facility. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.25%—2.25%, depending on the utilization of the borrowing base, or, if we elect, LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At December 31, 2012, the interest rate on the credit facility was 3.21%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.1 million on an annual basis, based on our outstanding indebtedness as of December 31, 2012. 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. The interest rate swap expired in August 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, 2012 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, 2012.

The effectiveness of our internal control over financial reporting as of December 31, 2012 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, 2012 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 2013 Annual Meeting of Stockholders which appears therein under the caption "Election of Directors—Board of Directors and Executive Officers," "—Code of Ethics" and "—Committees of the Board of Directors."

Audit Committee and Audit Committee Financial Expert

The Audit Committee of our board of directors consists of C. Scott. Bartlett, Jr., W. Dean Karrash, Paul A. Powell, Jr. and Brian L. Melton. The board of directors has determined that each of the members of the Audit Committee is independent as determined in accordance with the listing standards of The NASDAQ Stock Market and Item 407(a) of Regulation S-K. In addition, the board of directors has determined that C. Scott Bartlett, Jr., as defined by SEC rules, is an audit committee financial expert.

Section 16(a) Compliance

Section 16(a) of the Exchange Act requires our directors and executive officers and persons who own more than 10% of a registered class of Abraxas equity securities to file with the SEC and The NASDAQ initial reports of ownership and reports of changes in ownership of Abraxas common stock. Officers, directors and greater than 10% stockholders are required by SEC regulations to furnish us with copies of all such forms they file. Based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required. We believe that all our directors and executive officers complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act during 2011.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2013 Annual Meeting of Stockholders which appears therein under the captions "Election of Directors—Committees of the Board of Directors" and "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 2013 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 2013 Annual Meeting of Stockholders which appears therein under the captions "Certain Transactions" and "Election of Directors – Director Independence."

Item 14. Principal Accountant Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2013 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services."

PART IV

Item 15. Exhibits Financial Statement Schedules

(a) 1. Consolidated Financial Statements

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(a) 2. Financial Statement Schedules

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

(a) 3. Exhibits

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

Exhibit Number	Description
3.1	Articles of Incorporation of Abraxas dated August 30, 1990. (Filed as Exhibit 3.1 to our Registration Statement on Form S-4, No. 33-36565. (the "S-4 Registration Statement")).
3.2	Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement).
3.3	Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement).
3.4	Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to our Registration Statement on Form S-3, No. 333-00398).
3.5	Articles of Amendment to the Articles of Incorporation of Abraxas dated as of August 12, 2000. (Filed as Exhibit 3.5 to our Annual Report on Form 10-K filed on April 2, 2001).
3.6	Certificate of Correction dated February 24, 2011 (Filed herewith).3.7 Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on November 17, 2008).
3.8	Certificate of Designation of Series 2010 Junior Participating Preferred Stock. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on March 17, 2010).
4.1	Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).
4.2	Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to our Annual Report on Form 10-K filed on March 31, 1995).
4.3	Rights Agreement, dated March 17, 2010 by and between Abraxas and American Stock Transfer and Trust Company. (Filed as Exhibit 4.1 to our Registration Statement on Form 8-A filed on March 17, 2010).
*10.1	Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to our Registration Statement on Form S-4, No. 333-18673 filed on December 24, 1996).
*10.2	Abraxas Petroleum Corporation Amended and Restated 1994 Long Term Incentive Plan. (Filed as Exhibit 10.4 to our Registration Statement on Form S-4, No. 333-120989 filed on January 12, 2005).

Exhibit Number	Description
*10.3	Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.4 to our Annual Report on Form 10-K filed March 14, 2007).
*10.4	Employment Agreement between Abraxas and Robert L. G. Watson. (Filed as Exhibit 10.19 to the Registration Statement on Form S-1, No. 333-95281 filed on January 24, 2000 (the "2000 S-1 Registration Statement")).
*10.5	Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the Registration Statement on Form S-3, No. 333-127480 filed on September 16, 2005 (the "S-3 Registration Statement")).
*10.6	Employment Agreement between Abraxas and William H. Wallace. (Filed as Exhibit 10.27 to the S-3 Registration Statement).
*10.7	Employment Agreement between Abraxas and Lee T. Billingsley. (Filed as Exhibit 10.28 to the S-3 Registration Statement).
*10.8	Employment Agreement between Abraxas and G. William Krog, Jr. (Filed as Exhibit 10.9 to our Annual report on Form 10-K filed March 15, 2012).
*10.9	Employment Agreement between Abraxas and Geoffrey R. King (Filed herewith)
*10.10	Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Appendix A to our Proxy Statement filed on April 15, 2010).
*10.11	Form of Stock Option Agreement under the Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed June 6, 2005).
*10.12	Abraxas Petroleum Corporation Senior Management Incentive Bonus Plan 2006. (Filed as Exhibit 10.17 to our Annual Report on Form 10-K filed March 23, 2006).
*10.13	Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Annex E to our Proxy Statement filed on September 8, 2009).
*10.14	Form of Employee Stock Option Agreement under the Abraxas 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed August 26, 2006).
10.15	Amended and Restated Credit Agreement dated as of June 30, 2011 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on July 6, 2011).
10.16	Amendment No. 2 to Second Amended and Restated Credit Agreement dated as of June 29, 2012 among Abraxas, the guarantors named therein, the lenders named therein and Société Générale, as administrative agent (Filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q filed on August 9, 2012).
10.17	Loan Agreement dated as of September 19, 2011 between Raven Drilling, LLC, as Borrower, and RBS Asset Finance, Inc., as Lender. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on September 23, 2011).
14.1	Abraxas Petroleum Corporation Code of Business Conduct and Ethics. (Filed as Exhibit 14.1 to our Annual Report on Form 10-K filed March 22, 2006).
21.1	Subsidiaries of Abraxas. (Filed as Exhibit 21.1 to our Annual Report on Form 10-K filed on March 15, 2012).
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 with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).

* Management Compensatory Plan or Agreement.

SIGNATURES

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

ABRAXAS PETROLEUM CORPORATION

By: /s/ Robert L.G. Watson	By: /s/ Geoffrey R. King	By: /s/ G. William Krog, Jr.
President and Principal Executive Officer	Vice President and Principal Financial Officer	Principal Accounting Officer

DATED: March 18, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Signature	Name and Title	Date
/s/ Robert L.G. Watson Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	March 18, 2013
/s/ Geoffrey R. King Geoffrey R. King	Vice President, CFO (Principal Financial Officer)	March 18, 2013
/s/ G. William Krog, Jr. G. William Krog, Jr.	Chief Accounting Officer (Principal Accounting Officer)	March 18, 2013
/s/ C. Scott. Bartlett, Jr. C. Scott Bartlett, Jr.	Director	March 18, 2013
/s/ Harold D. Carter Harold D. Carter	Director	March 18, 2013
/s/ Ralph F. Cox Ralph F. Cox	Director	March 18, 2013
/s/ W. Dean Karrash W. Dean Karrash	Director	March 18, 2013
/s/ Dennis E. Logue Dennis E. Logue	Director	March 18, 2013
/s/ Brian L. Melton Brian L. Melton	Director	March 18, 2013
/s/ Paul A. Powell, Jr. Paul A. Powell, Jr.	Director	March 18, 2013
/s/ Edward P. Russell Edward P. Russell	Director	March 18, 2013

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

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation as of December 31, 2011 and 2012 and the related consolidated statements of operations and other comprehensive income (loss), stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2012. 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, 2011 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012**,** 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, 2012, 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 18, 2013 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Dallas, Texas
March 18, 2013

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, 2012, 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, 2012, 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, 2011 and 2012, and the related consolidated statements of operations and other comprehensive income (loss), stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2012 and our report dated March 18, 2013 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Dallas, Texas
March 18, 2013

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2011	December 31, 2012
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ —	$ 2,061
Accounts receivable:		
Joint owners	3,354	8,883
Oil and gas production sales	8,897	10,887
Other	655	661
	12,906	20,431
Derivative asset	11,416	41
Other current assets	391	488
Total current assets	24,713	23,021
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	490,908	563,317
Unproved properties excluded from depletion	1,100	2,089
Other property and equipment	33,783	37,833
Total	525,791	603,239
Less accumulated depreciation, depletion, and amortization	(346,239)	(390,407)
Total property and equipment, net	179,552	212,832
Investment in joint venture	26,215	—
Deferred financing fees, net	3,490	3,397
Derivative asset	6,412	594
Other assets	768	763
Total assets	$ 241,150	$ 240,607

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2011	December 31, 2012
	(In thousands, except number of shares)	
Current liabilities:		
Accounts payable	$ 21,373	$ 42,387
Joint interest oil and gas production payable	5,835	6,947
Accrued interest	209	75
Other accrued expenses	284	962
Derivative liability	11,640	3,462
Current maturities of long-term debt	181	657
Total current liabilities	39,522	54,490
Long-term debt—less current maturities	126,258	124,101
Other liabilities	—	367
Derivative liability	4,307	3,568
Future site restoration	8,412	11,381
Total liabilities	178,499	193,907
Commitments and contingencies (Note 8)		
Stockholders' Equity:		
Preferred stock, par value $.01 per share—authorized 1,000,000 shares; -0- shares issued and outstanding	—	—
Common stock, par value $.01 per share—authorized 200,000,000 shares; issued and outstanding 92,261,057 and 92,733,448	923	927
Additional paid-in capital	248,480	250,998
Accumulated deficit	(186,465)	(205,256)
Accumulated other comprehensive income (loss)	(287)	31
Total stockholders' equity	62,651	46,700
Total liabilities and stockholders' equity	$ 241,150	$ 240,607

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2010	2011	2012
	(In thousands except per share data)		
Revenues:			
Oil and gas production revenues	$ 58,050	$64,615	$ 68,499
Other	10	7	74
	58,060	64,622	68,573
Operating costs and expenses:			
Lease operating	19,475	21,581	24,806
Production taxes	5,910	5,766	6,613
Depreciation, depletion, and amortization	16,212	16,194	23,016
Impairment	4,787	—	19,774
General and administrative (including stock-based compensation of $1,560, $1,987 and $2,091, respectively)	8,869	9,433	10,712
	55,253	52,974	84,921
Operating income (loss)	2,807	11,648	(16,348)
Other (income) expense:			
Interest income	(8)	(7)	(4)
Interest expense	9,106	4,898	5,520
Amortization of deferred financing fees	2,479	1,762	937
Gain on derivative contracts (unrealized $(10,285), $(7,476) and $(2,669))	(10,811)	(6,800)	(2,210)
Equity in loss (income) of joint venture	473	(2,187)	(2,207)
Other	(119)	316	97
	1,120	(2,018)	2,133
Income (loss) before income tax	1,687	13,666	(18,481)
Income tax benefit (expense)	79	77	(310)
Net income (loss)	$ 1,766	$13,743	$(18,791)
Net income (loss)—per common share—basic	$ 0.02	$ 0.15	$ (0.20)
Net income (loss)—per common share—diluted	$ 0.02	$ 0.15	$ (0.20)

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2010	2011	2012
	(In thousands)		
Consolidated net income (loss)	$1,766	$13,743	$(18,791)
Other comprehensive income (loss):			
Change in unrealized value of investments	(27)	(76)	(25)
Foreign currency translation adjustment	70	(456)	343
Other comprehensive income (loss)	43	(532)	318
Comprehensive income (loss)	$1,809	$13,211	$(18,473)

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)	Total
Balance at December 31, 2009	76,231,751	$762	$182,647	$(201,974)	$ 202	(18,363)
Net income	—	—	—	1,766	—	1,766
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	(27)	(27)
Foreign currency translation adjustment	—	—	—	—	70	70
Stock-based compensation	—	—	1,560	—	—	1,560
Shares issued for compensation	11,480	—	24	—	—	24
Stock options exercised	163,705	2	67	—	—	69
Warrants exercised	15,534	—	—	—	—	—
Other	—	—	(75)	—	—	(75)
Restricted stock issued, net of cancellations	5,091	—	—	—	—	—
Balance December 31, 2010	76,427,561	764	184,223	(200,208)	245	(14,976)
Net income	—	—	—	13,743	—	13,743
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	(76)	(76)
Foreign currency translation adjustment	—	—	—	—	(456)	(456)
Stock-based compensation	—	—	1,987	—	—	1,987
Shares issuance	15,075,502	151	62,195	—	—	62,346
Stock options exercised	371,632	4	79	—	—	83
Restricted stock issued, net of cancellations	386,362	4	(4)	—	—	—
Balance December 31, 2011	92,261,057	923	248,480	(186,465)	(287)	62,651
Net income	—	—	—	(18,791)	—	(18,791)
Change in unrealized gain (loss) on fair value of investments	—	—	—	—	(25)	(25)
Foreign currency translation adjustment	—	—	—	—	343	343
Stock-based compensation	—	—	2,091	—	—	2,091
Stock options exercised	390,957	4	427	—	—	431
Restricted stock issued, net of cancellations	81,434	—	—	—	—	—
Balance December 31, 2012	92,733,448	$927	$250,998	$(205,256)	$ 31	$ 46,700

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2010	2011	2012
	(In thousands)		
Operating Activities			
Net income (loss) income	$ 1,766	$ 13,743	$(18,791)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Equity in loss (income) of joint venture	473	(2,187)	(2,207)
Change in derivative fair value	(10,451)	(7,680)	(4,088)
Monetization of derivative contracts	—	—	12,364
Depreciation, depletion, and amortization	16,212	16,194	23,016
Impairment	4,787	—	19,774
Accretion of future site restoration	516	452	474
Amortization of deferred financing fees	2,479	1,762	937
Stock-based compensation	1,560	1,987	2,091
Other non-cash transactions	24	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(3,976)	(182)	(7,506)
Other assets and liabilities	(113)	(17)	250
Accounts payable	14,210	756	22,024
Accrued expenses	(3,385)	(333)	3,037
Net cash provided by operating activities	24,102	24,495	51,375
Investing Activities			
Capital expenditures, including purchases and development of properties	(36,448)	(79,012)	(68,552)
Proceeds from the sale of oil and gas properties	21,400	8,457	21,549
Net cash used in investing activities	(15,048)	(70,555)	(47,003)
Financing Activities			
Proceeds from exercise of stock options and warrants	69	83	431
Proceeds from issuance of common stock, net of offering costs	—	62,346	—
Proceeds from long-term borrowings	3,000	50,500	30,500
Payments on long-term borrowings	(13,641)	(65,153)	(32,181)
Deferred financing fees	(169)	(1,758)	(844)
Other	(75)	(52)	(217)
Net cash (used in) provided by financing activities	(10,816)	45,966	(2,311)
Effect of exchange rate changes on cash	—	(5)	—
(Decrease) increase in cash	(1,762)	(99)	2,061
Cash at beginning of year	1,861	99	—
Cash at end of year	$ 99	$ —	$ 2,061

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(CONTINUED)

	Years Ended December 31,		
	2010	2011	2012
	(In thousands)		
Supplemental disclosures of cash flow information:			
Interest paid	$ 8,876	$4,514	$ 5,180
Non-Cash Investing Activities:			
Asset retirement obligation cost and liabilities	$ (83)	$ (8)	$ 2,588
Non-cash transfer of investment in joint venture	—	—	28,531
Asset retirement obligations associated with property acquisitions and dispositions	$ (2,735)	$ 306	$ 324
Properties contributed to joint venture	$24,500	$ —	$ —

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

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

Rig Accounting

In accordance with SEC Regulation S-X, no income is recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates holds an ownership, or other economic interest. Any income not recognized as a result of this limitation is credited to the full cost pool and recognized through lower amortization as reserves are produced.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and derivative contracts. Accounts receivable are generally from companies with significant oil and gas marketing activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers. The counterparties to our derivative contracts are the same financial institutions from which we have outstanding debt; accordingly, we believe our exposure to credit risk to these counterparties is currently mitigated in part by this, as well as the current overall financial condition of the counterparties.

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

Cash and Equivalents

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

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $84,000 and $105,000 at December 31, 2011 and 2012, respectively. The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties, except in unusual circumstances. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. As of December 31, 2010, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves; however, the net capitalized costs of oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $4.8 million resulting in a write down for the year ended December 31, 2010. As of December 31, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of December 31, 2012, 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 $19.8 million resulting in a write down for the year ended December 31, 2012. Write downs of $1.3 million, $11.8 million and $6.7 million were taken in the second, third and fourth quarters of 2012 respectively.

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.

Estimates of Proved Oil and Gas Reserves

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

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

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

In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the average 12 month first-day-of-month pricing for the years ended December 31, 2011 and 2012, and costs as of December 31, 2011 and 2012. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact depreciation, depletion and amortization, or DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields.

Derivative Instruments and Hedging Activities

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

The Company accounts for derivative gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for hedge accounting rules as prescribed by Accounting Standards Codification ("ASC") 815. Accordingly, we do not account for our derivative instruments as cash flow hedges for financial reporting purposes and instead record their fair value on the balance sheet with adjustments to the carrying value of the instruments being recognized as a gain or loss in the current period.

Fair Value of Financial Instruments

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

Share-Based Payments

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted are valued at the date of grant and expense is recognized over the vesting period. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such restricted stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2010, 2011 and 2012, stock-based compensation was approximately \$1.6 million, \$2.0 million and \$2.1 million, respectively. For additional information regarding share-based payments, refer to Note 6, "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:

	2010	2011	2012
	(In thousands)		
Beginning asset retirement obligation	$10,326	$7,734	$ 8,412
New wells placed on production and other	64	318	330
Deletions related to property disposals and plugging costs	(3,089)	(84)	(423)
Accretion expense	516	452	474
Revisions	(83)	(8)	2,588
Ending asset retirement obligation	$ 7,734	$8,412	$11,381

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, 2011 and 2012.

During 2010 and 2011, two purchasers accounted for 21% and 28% of oil and gas revenues, respectively. During 2012, three purchasers accounted for 39% of oil and gas revenues.

Deferred Financing Fees

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

Income Taxes

The Company records deferred income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to be in effect to taxable income in the years in which those temporary differences are expected to be recovered or settled. Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10. Therefore, we have established a valuation allowance of $89.7 million for deferred tax assets at December 31, 2012.

Accounting for Uncertainty in Income Taxes

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

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

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

Other Comprehensive Income (Loss)

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

2. Joint Venture

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

On September 4, 2012, Abraxas Petroleum Corporation entered into an Agreement to dissolve Blue Eagle with Rock Oil. The effective date of the dissolution was August 31, 2012.

Under the terms of the Agreement, Abraxas retained a 100 percent interest to the base of the Buda formation in Jourdanton, Atascosa County (4,401 net acres), a 100 percent interest in Yoakum, DeWitt County (1,868 net acres), a 25 percent interest in WyCross, McMullen County (695 net acres), and a 25 percent interest in Nordheim, DeWitt County (532 net acres). We also received $7.0 million in cash, adjusted for various working capital components, and will receive 25% of the cash and working capital in Blue Eagle upon its final liquidation.

Through August 31, 2012 we accounted for the joint venture under the equity method of accounting in accordance with ASC 323. Under this method, Abraxas' share of net income (loss) from the joint venture is reflected as an increase (decrease) in its investment account in *"Investment in joint venture"* and was also recorded as equity investment income (loss) in *"Equity in (income) loss of joint venture."* For the years ended December 31, 2011 and 2012 we reported income of $2.2 million and $2.2 million, respectively, related to Blue Eagle.

The following is condensed financial data from Blue Eagle's August 31, 2012 (date of dissolution) and December 31, 2011 financial statements:

Balance Sheets:

	As of December 31, 2011	As of August 31, 2012
Assets:		
Current assets	$11,910	$ 7,921
Oil and gas properties	66,663	75,741
Other assets	36	30
Total assets	$78,609	$83,692
Liabilities and Members' Capital:		
Current liabilities	$ 3,070	$ 1,474
Other liabilities	41	48
Members' capital	75,498	82,170
Total liabilities and members' capital	$78,609	$83,692

Statement of Operations:

	Year Ended December 31, 2011	Year Ended December 31, 2012(1)
	(In thousands)	
Revenue	$12,579	$12,106
Operating expenses	7,138	7,144
Other income	(11)	(4)
Net income	$ 5,452	$ 4,966

(1) Through August 31, 2012

Form 10-K

3. Divestiture of Non-Core Properties

In the third quarter of 2012 we sold certain non-core assets for combined net proceeds of approximately $21.5 million. Properties sold included certain properties received upon the dissolution of the Blue Eagle joint venture. The net proceeds were used to repay outstanding indebtedness under our credit facility, for capital expenditures and general corporate purposes. Proceeds from these sales were credited to the full cost pool as the sale was not significant under full cost accounting rules.

4. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2011 and 2012, respectively:

	December 31, 2011	December 31, 2012
	(In thousands)	
Senior secured credit facility	$115,000	$113,000
Rig loan agreement	6,500	7,000
Real estate lien note	4,939	4,758
	126,439	124,758
Less current maturities	(181)	(657)
	$126,258	$124,101

Maturities of long-term debt are as follows:

Year ending December 31, (In thousands)	
2013	$ 657
2014	2,117
2015	119,364
2016	2,085
2017	535
Thereafter	—
	$124,758

Credit Facility

We have a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of December 31, 2012, $113.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At December 31, 2012, we had a borrowing base of $150.0 million. This amount will remain in effect until the next redetermination of the borrowing base which is scheduled to be completed in April 2013. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our Proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base was increased to $150.0 million based upon our reserve report dated June 30, 2012, and did not include any of the properties held for sale. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At December 31, 2012, the interest rate on the credit facility was 3.21% based on 1-month LIBOR borrowings and level of utilization.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

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

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 of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 4.00 to 1.00 and liquidity (defined as the sum of our borrowing base availability, liquid investments and unrestricted cash) of at least $7.5 million for each fiscal quarter ending on or after June 30, 2012 and on or before March 31, 2013. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and 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. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements.

As of December 31, 2012, the interest coverage ratio was 7.72 to 1.00, the total debt to EBITDAX ratio was 2.97 to 1.00, our current ratio was 1.19 to 1.00 and we had liquidity of $39.1 million, which included $37.0 million of availability under the credit facility. At December 31, 2012 we were in compliance with all of our debt covenants.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

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

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

Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2000 HP diesel electric drilling rig (the "Collateral"). The rig loan agreement provided for interim borrowings payable to Raven Drilling until the final amount of the loan was determined.

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

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

Real Estate Lien Note

On May 9, 2008, the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as its corporate headquarters. This note was refinanced in November 2008. The note bears interest at a fixed rate of 5.25% and is payable in monthly installments of principal and interest of $36,652 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2011 and 2012, $4.9 million and $4.8 million, respectively, was outstanding on the note,

5. Property and Equipment

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

	Estimated Useful Life	December 31, 2011	December 31, 2012
	Years	(In thousands)	
Oil and gas properties	—	$492,008	$565,406
Equipment and other	3-39	16,330	19,052
Drilling rig	15	17,453	18,781
		$525,791	$603,239

6. Stock-based Compensation, Option Plans and Warrants

Stock Options

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. The fair value for these options was estimated at the date of grant using the following weighted average assumptions for 2010, 2011 and 2012:

	2010	2011	2012
Weighted average value per option granted during the period	$ 1.61	$ 3.11	$ 2.17
Assumptions:(1)(2)			
Expected dividend yield	0%	0%	0%
Volatility	84.0%	80.0%	81.4%
Risk free interest rate	2.87%	2.21%	1.19%
Expected life (years)	9.0 years	6.4 years	6.7 years
Fair value of options granted (in thousands)	$ 1,553	$ 2,506	$ 1,324

(1) The estimated future forfeiture rate is based on the Company's historical forfeiture rate.
(2) The Company does not pay dividends on its common stock.

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

The Company's 2005 Employee Long-Term Equity Incentive Plan has authorized the grant of up to 5.2 million awards to management and employees, including options. Options have a term not to exceed 10 years. Options issued under this plan vest according to a vesting schedule as determined by the compensation committee of the Company's board of directors. Vesting may occur upon (1) the attainment of one or more performance goals or targets established by the committee, (2) the optionee's continued employment or service for a specified period of time, (3) the occurrence of any event or the satisfaction of any other condition specified by the committee, or (4) a combination of any of the foregoing.

The following table is a summary of the Company's stock option activity for the three years ended December 31, 2012:

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Intrinsic value per share
Options outstanding December 31, 2009	4,090	$2.18		
Granted	964	2.12		
Exercised	(213)	0.89		
Forfeited/Expired	(21)	2.93		
Options outstanding December 31, 2010	4,820	$2.23		
Granted	807	4.37		
Exercised	(530)	1.54		
Forfeited/Expired	(341)	3.01		
Options outstanding December 31, 2011	4,756	$2.61		
Granted	610	$3.01		
Exercised	(391)	1.11		
Forfeited/Expired	(214)	2.80		
Options outstanding December 31, 2012	4,761	$2.77	6.5 years	$1.98
Exercisable at end of year	2,992	$2.75	5.7 years	$1.95

Other information pertaining to the Company's stock option activity for the three years ended December 31, 2012:

	2010	2011	2012
Weighted average grant date fair value of stock options granted (per share)	$1.61	$ 3.11	$ 2.17
Total fair value of options vested (000's)	$ 949	$1,230	$1,497
Total intrinsic value of options exercised (000's)	$ 373	$1,584	$ 414

As of December 31, 2012, the total compensation cost related to non-vested awards not yet recognized was approximately $2.5 million, which will be recognized in 2013 through 2016. For the years ended December 31, 2010, 2011 and 2012, we recognized $1.2 million, $1.5 million and $1.6 million respectively, 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, 2012:

	Options outstanding			Exercisable		
	Number outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable	Weighted average remaining life	Weighted average exercise price
$0.68 – 0.99	743,793	5.68	$0.96	548,293	5.50	$0.95
$1.00 – 1.99	1,130,629	7.27	$1.75	696,677	6.75	$1.68
$2.00 – 2.99	924,225	7.17	$2.26	563,159	7.13	$2.36
$3.00 – 3.99	719,763	7.61	$3.65	276,713	5.41	$3.60
$4.00 – 4.99	1,168,500	5.47	$4.58	833,625	4.38	$4.53
$5.00 – 6.05	74,000	3.15	$6.05	74,000	3.15	$6.05
	4,760,910			2,992,467		

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. As of December 31, 2012, the total compensation cost related to non-vested awards not yet recognized was approximately $1.1 million, which will be recognized in 2013 through 2016. For the years ended December 31, 2010, 2011 and 2012, we recognized $0.4 million, $0.5 million and $0.5 million, respectively, 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, 2012:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2009	548,908	$2.05
Granted	20,000	2.45
Vested/Released	(155,268)	2.22
Forfeited	(13,345)	1.85
Unvested December 31, 2010	400,295	$2.02
Granted	408,676	3.67
Vested/Released	(156,890)	2.24
Forfeited	(22,310)	2.27
Unvested December 31, 2011	629,771	$3.03
Granted	89,860	2.12
Vested/Released	(229,172)	2.57
Forfeited	(8,434)	2.42
Unvested December 31, 2012	482,025	$3.09

Director Stock Awards

Shares Reserved and Awards. The 2005 Directors Plan (as amended) reserves 1.5 million shares of Abraxas common stock, subject to adjustment following certain events. The 2005 Directors Plan provides that each year, at the first regular meeting of the board of directors immediately following Abraxas' annual stockholder's meeting, each non-employee director shall be granted or issued awards of 12,000 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 100,000 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise price shall be no less than 100% of the fair market value on the date of the award while the option terms and vesting schedules are at the discretion of the committee. In addition to the 12,000 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 2010, there were 11,480 shares issued related to this compensation. The number of shares issued was determined based on the stock price on the date of issuance. Between April 2010 and April 2011, directors were compensated for their annual retainer fee of $26,000 in cash, which increased to $27,500 in April 2011 and to $40,000 in April 2012.

At December 31, 2012, the Company had approximately 9.2 million shares reserved for future issuance for conversion of its stock options, warrants, and incentive plans for the Company's directors, employees and consultants.

Warrants

On May 25, 2007, Abraxas entered into a Securities Purchase Agreement with certain accredited investors pursuant to which Abraxas issued warrants to purchase 1,174,938 shares of common stock. The warrants expired on May 25, 2012. There were 877,941 warrants outstanding at expiration.

7. Income Taxes

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

	Years Ended December 31,		
	2010	2011	2012
		(In thousands)	
Deferred tax liabilities:			
Marketable securities	$ 57	$ 36	$ 28
Canada full cost pool	—	377	—
Investment in Blue Eagle	7,107	7,527	—
Hedge contracts	—	345	—
Total deferred tax liabilities	7,164	8,285	28
Deferred tax assets:			
U.S. full cost pool	37,464	29,976	13,837
Canada full cost pool	1,238	—	3,720
Depletion carryforward	4,667	4,842	4,930
U.S. net operating loss carryforward	49,621	52,564	59,362
Canada net operating loss carryforward	301	2,151	4,196
Alternative minimum tax credit	422	422	422
Hedge contracts	1,904	—	2,231
Other	3,447	1,811	1,042
Total deferred tax assets	99,064	91,766	89,740
Valuation allowance for deferred tax assets	(91,900)	(83,481)	(89,712)
Net deferred tax assets	7,164	8,285	28
Net deferred tax	$ —	$ —	$ —

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

	Years ended December 31,		
	2010	2011	2012
		(In thousands)	
Current:			
Federal	$ —	$(77)	$310
State	(79)	—	—
Foreign	—	—	—
	$(79)	$(77)	$310
Deferred:			
Federal	$ —	$ —	$ —
Foreign	—	—	—
	$ —	$ —	$ —

At December 31, 2012, the Company had, subject to the limitation discussed below, $169.6 million of net operating loss carryforwards for U.S. tax purposes, and $15.0 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire in varying amounts through 2032 and the Canadian loss carryforward will expire in 2032, 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 $91.9 million at December 31, 2010, $83.5 million at December 31, 2011 and $89.7 million at December 31, 2012.

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

	Years ended December 31,		
	2010	2011	2012
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	$ (591)	$(4,809)	$ 6,468
(Increase) decrease in deferred tax asset valuation allowance	(412)	5,408	(6,231)
Basis difference in hedge liability	1,890	—	—
Rate differential for non U.S. income	(385)	(46)	(1,533)
State income taxes	—	—	
Accrual of prior year federal taxes (2009)	—	—	(310)
Permanent differences	(409)	(533)	(732)
Increase in asset for partnership distribution	—	—	1,945
Other	(14)	57	83
	$ 79	$ 77	$ (310)

During 2012, the Company reduced deferred tax assets by $2.1 million related the full cost pool assets and the net operating loss carryforward. The deferred tax assets were fully offset by a valuation allowance which was reduced at the same time. There were no deferred income tax expense or benefit due to losses and/or loss carryforwards and valuation allowances which have been recorded against such benefits.

The Company accounts for uncertain tax positions under provisions ASC 740-10. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2012, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2002 through 2012 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly owned subsidiary of Abraxas, have undergone audits of their 2009 Federal income tax returns. The audit of the Federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of a proposed adjustment of $619,000. The Company does not agree with the findings and intends to aggressively appeal the proposed adjustment; however, no assurances can be made that such appeals will be successful. For the year ended December 31, 2012, the Company accrued $310,000 in income tax expense related to the audit of its 2009 Federal tax return. This amount was determined by an analysis of what the amount that is greater than 50% likely to be paid upon final settlement.

8. Commitments and Contingencies

Operating Leases

The Company leases office space in Calgary, Alberta. During 2010, 2011 and 2012, rent expense of $91,528 CN ($88,511 USD) ; $102,453 CN ($121,500 USD) and $112,261 CN ($112,276 USD), respectively, was incurred related to this lease. In July 2011, the Company leased office space in Dickinson, North Dakota. During 2011 and 2012, rent expense of $9,250 and $23,800, respectively was incurred related to this lease. This lease expires on August 31, 2013.

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, 2012, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

9. Earnings per Share

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

	Years ended December 31:		
	2010	2011	2012
	(In thousands, except per share data)		
Numerator:			
Net income (loss)	$ 1,766	$13,743	$(18,791)
Denominator:			
Denominator for basic earnings per share—weighted-average common shares outstanding	75,923	90,151	91,914
Effect of dilutive securities:			
Stock options, restricted shares and warrants	1,301	2,093	—
Dilutive potential common shares:			
Denominator for diluted earnings per share—adjusted weighted-average shares and assumed exercise of options, restricted shares and warrants	77,224	92,244	91,914
Net income (loss) per common share—basic	$ 0.02	$ 0.15	$ (0.20)
Net income (loss) per common share—diluted	$ 0.02	$ 0.15	$ (0.20)

Basic earnings per share, excluding any dilutive effects of stock options, warrants and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities. For the year ended December 31, 2012, 1,348,924 potential shares relating to stock options and unvested restricted shares were excluded from the calculation of diluted income (loss) per share since their inclusion would have been anti-dilutive due to the loss incurred in the period. None of the dilutive shares were excluded for the years ended December 31, 2010 and 2011.

10. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2011 and 2012 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2011				
Net revenue	$ 13,847	$16,656	$ 17,666	$ 16,453
Operating income	$ 2,503	$ 3,438	$ 4,225	$ 1,482
Net (loss) income	$(10,019)	$ 8,937	$ 20,085	$ (5,260)
Net (loss) income per common share—basic	$ (0.12)	$ 0.10	$ 0.22	$ (0.06)
Net (loss) income per common share—diluted	$ (0.12)	$ 0.10	$ 0.21	$ (0.06)
Year Ended December 31, 2012				
Net revenue	$ 16,396	$15,938	$ 17,170	$ 19,069
Operating income (loss)	$ 2,224	$ (23)	$(11,359)	$ (7,190)
Net income (loss) income	$ 817	$10,903	$(18,644)	$(11,867)
Net income (loss) per common share—basic	$ 0.01	$ 0.12	$ (0.20)	$ (0.13)
Net income (loss) per common share—diluted	$ 0.01	$ 0.12	$ (0.20)	$ (0.13)

11. Benefit Plans

The Company has a defined contribution plan (401(k) plan) covering all eligible employees. In 2010, 2011 and 2012, in accordance with the safe harbor provisions of the plan, the Company contributed $177,817, $226,377 and $267,289, respectively, to the plan. The Company adopted the safe harbor provisions for its 401(k) plan which requires us to contribute a fixed match to each participating employee's contribution to the plan. The fixed match is set at the rate of dollar for dollar on the first 1% of eligible pay contributed, then 50 cents on the dollar for each additional percentage point of eligible pay contributed, up to 5%. Employee's eligible pay with respect to calculating the fixed match is limited by IRS regulations. In addition, the Board of Directors, at its sole discretion, may authorize the Company to make additional contributions to each participating employee's plan. The employee contribution limit for 2010 and 2011 was $16,500 for employees under the age of 50 and $22,000 for employees 50 years of age or older. For 2012 the employee contribution limit was $17,000 for employees under the age of 50 and $22,500 for employees 50 years of age or older.

12. 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 our consolidated oil and gas revenue, Two customers accounted for approximately 20% of United States revenue and one customer accounted for 100% of revenue in Canada. In 2011, three customers accounted for approximately 28% of our consolidated oil and gas revenue. Two customers accounted for approximately 26% of United States revenue and one customer accounted for 100% of revenue in Canada. In 2012, four customers accounted for approximately 42% of our consolidated oil and gas revenue. Three customers accounted for approximately 39% 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, 2011 and 2012

	Year Ended December 31, 2010			
	U.S.	Canada	Corporate	Total
	(In thousands)			
Revenues:				
Oil and gas production	$57,990	$ 60	$ —	$ 58,050
Other	—	—	10	10
	57,990	60	10	58,060
Costs and expenses:				
Lease operating	19,459	16	—	19,475
Production taxes	5,910	—	—	5,910
Depreciation, depletion and amortization	15,603	66	543	16,212
Impairment	—	4,787	—	4,787
General and administrative	1,635	688	6,546	8,869
Net interest	—	—	9,098	9,098
Amortization of deferred financing fees	—	—	2,479	2,479
Equity in loss of joint venture	—	—	473	473
Other	—	—	(10,930)	(10,930)
Income (loss) before tax	$15,383	$(5,497)	$ (8,199)	$ 1,687

	Year Ended December 31, 2011			
	U.S.	Canada	Corporate	Total
	(In thousands)			
Revenues:				
Oil and gas production	$63,105	$1,510	$ —	$64,615
Other	—	—	7	7
	63,105	1,510	7	64,622
Costs and expenses:				
Lease operating	20,788	793	—	21,581
Production taxes	5,764	2	—	5,766
Depreciation, depletion and amortization	15,236	709	249	16,194
General and administrative	1,698	654	7,081	9,433
Net interest	448	4	4,439	4,891
Amortization of deferred financing fees	—	—	1,762	1,762
Equity in (income) of joint venture	—	—	(2,187)	(2,187)
Other	—	—	(6,484)	(6,484)
Income (loss) before tax	$19,171	$ (652)	$(4,853)	$13,666

	Year Ended December 31, 2012			
	U.S.	Canada	Corporate	Total
	(In thousands)			
Revenues:				
Oil and gas production	$65,590	2,909	—	68,499
Other	—	—	74	74
	65,590	2,909	74	68,573
Costs and expenses:				
Lease operating	22,578	2,228	—	24,806
Production taxes	6,588	25	—	6,613
Depreciation, depletion and amortization	20,704	2,063	249	23,016
Impairment	—	19,774	—	19,774
General and administrative	1,980	699	8,033	10,712
Net interest	457	17	5,042	5,516
Amortization of deferred financing fees	—	—	937	937
Equity in (income) of joint venture	—	—	(2,207)	(2,207)
Other	—	—	(2,113)	(2,113)
Income (loss) before tax	$13,283	(21,897)	(9,867)	(18,481)

The following table provides the Company's geographic asset data as of December 31, 2011 and December 31, 2012:

Segment Assets:

	December 31, 2011	December 31, 2012
	(In thousands)	
United States	$167,739	$223,253
Canada	19,379	7,053
Corporate	54,032	10,301
	$241,150	$240,607

13. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Our derivative contracts do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period.

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The following table sets forth the summary position of our derivative contracts as of December 31, 2012:

Contract Periods	Oil	
	Daily Volume (Bbl)	Swap Price (per Bbl)
2013	1,341	$86.70
2014	1,100	$92.58
2015	933	$85.00
2016	883	$84.00

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 interest rate swap expired in August 2012.

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

Fair Value of Derivative Instruments as of December 31, 2011

Derivatives not designated as hedging instruments	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives—current	$11,416	Derivatives—current	$10,094
Interest rate derivatives	Derivatives—current	—	Derivatives—current	1,546
Commodity price derivatives	Derivatives—long-term	6,412	Derivatives—long-term	4,307
		$17,828		$15,947

Fair Value of Derivative Instruments as of December 31, 2012

Derivatives not designated as hedging instruments	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives—current	$ 41	Derivatives—current	$3,462
Commodity price derivatives	Derivatives—long-term	594	Derivatives—long-term	3,568
		$635		$7,030

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

14. Financial Instruments

Effective January 1, 2008, the Company adopted ASC 820-10 which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. The implementation of ASC 820-10 did not cause a change in the method of calculating fair value of our assets or liabilities, with the exception of incorporating a measure of the Company's own non-performance risk or that of its counter-parties, as appropriate, which was not material. The primary impact from adoption was additional disclosures.

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

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2011 and 2012, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2011
Assets:				
Investment in common stock	$104	$ —	$ —	$ 104
NYMEX Fixed Price Derivative contracts	—	17,828	—	17,828
Total Assets	$104	$17,828	$ —	$17,932
Liabilities:				
NYMEX Fixed Price Derivative contracts	$ —	$14,401	$ —	$14,401
Interest Rate Swaps	—	—	1,546	1,546
Total Liabilities	$ —	$14,401	$1,546	$15,947

	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, 2012
Assets:				
Investment in common stock	$78	$ —	$—	$ 78
NYMEX Fixed Price Derivative contracts	—	635	—	635
Total Assets	$78	$ 635	$—	$ 713
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$7,030	$—	$7,030
Total Liabilities	$—	$7,030	$—	$7,030

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, 2012 in US dollars. Accordingly, this investment is characterized as Level 1.

The Company's derivative contracts consist of NYMEX-based fixed price commodity swaps and interest rate swaps. The NYMEX-based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, we enter the various inputs into a model and compare our results to the third party for reasonableness.

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. This interest rate swap expired in August 2012 and was not renewed.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3) for the three years ended December 31, 2012 is as follows (in thousands):

	Derivative Assets (Liabilities)—net
Balance December 31, 2010	$(3,348)
Total realized and unrealized losses included in change in net liability	(565)
Settlements during the period	2,367
Balance December 31, 2011	(1,546)
Total realized and unrealized losses included in change in net liability	(214)
Settlements during the period	1,760
Balance December 31, 2012	—

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

15. 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					
	2011			2012		
	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)					
Proved oil and gas properties	$ 490,908	$ 468,218	$22,690	$ 563,317	$ 531,971	$ 31,346
Unproved properties	1,100	—	1,100	2,089	—	2,089
Total	492,008	468,218	23,790	565,406	531,971	33,435
Accumulated depreciation, depletion, amortization and impairment	(341,264)	(335,871)	(5,393)	(383,469)	(356,255)	(27,214)
Net capitalized costs	$ 150,744	$ 132,347	$18,397	$ 181,937	$ 175,716	$ 6,221

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

	Years Ended December 31								
	2010			2011			2012		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Development costs	$31,278	$23,757	$7,521	$46,735	$32,471	$14,264	$56,318	$48,283	$8,035
Exploration costs	3,809	3,809	—	8,410	8,410	—	—	—	—
Property acquisition costs	—	—	—	—	—	—	7,200	7,200	—
Unproved	1,085	—	1,085	1,100	—	1,100	989	—	989
	$36,172	$27,566	$8,606	$56,245	$40,881	$15,364	$64,507	$55,483	$9,024

The results of operations for oil and gas producing activities for the three years ended December 31, 2010, 2011 and 2012 are as follows:

	Years Ended December 31,								
	2010			2011			2012		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Revenues	$ 58,050	$ 57,990	$ 60	$ 64,615	$ 63,105	$1,510	$ 68,499	$ 65,590	$ 2,909
Production costs	(25,790)	(25,774)	(16)	(27,347)	(26,552)	(795)	(31,419)	(29,166)	(2,253)
Depreciation, depletion, and amortization	(15,653)	(15,603)	(50)	(15,595)	(14,914)	(681)	(22,767)	(20,704)	(2,063)
Proved property impairment	(4,787)	—	(4,787)	—	—	—	(19,774)	—	(19,774)
General and administrative	(2,323)	(1,635)	(688)	(2,352)	(1,698)	(654)	(2,679)	(1,980)	(699)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 9,497	$ 14,978	$(5,481)	$ 19,321	$ 19,941	$ (620)	$ (8,140)	$ 13,740	$(21,880)
Depletion rate per barrel of oil equivalent	$ 11.00	$ 10.98	$ 59.97	$ 12.26	$ 11.96	$27.58	$ 15.59	$ 14.74	$ 37.48

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, 2010, 2011, and 2012. The Company's management emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been predominately prepared by independent petroleum reserve engineers. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company's proved reserves are located in the continental United States and Canada.

Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, the average prior 12-month-first-day-of-the-month commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows for the periods presented.

	Total			United States			Canada		
	Oil/ NGL	Gas	Oil Equivalents	Oil/ NGL	Gas	Oil Equivalents	Oil/ NGL	Gas	Oil Equivalents
	(MBbl)	(MMcf)	(MBoe)	(MBbl)	(MMcf)	(MBoe)	(MBbl)	(MMcf)	(MBoe)
	(In thousands)								
Proved developed and undeveloped reserves:									
Balance at December 31, 2009	8,832	96,525	24,919	8,832	96,525	24,919	—	—	—
Revisions of previous estimates	1,067	729	1,189	1,067	729	1,189	—	—	—
Extensions and discoveries	1,329	1,456	1,572	1,252	1,066	1,430	77	390	142
Sales of minerals in place	(925)	(8,318)	(2,311)	(925)	(8,318)	(2,311)	—	—	—
Production	(509)	(5,479)	(1,422)	(508)	(5,479)	(1,421)	(1)	—	(1)
Balance at December 31, 2010	9,794	84,913	23,947	9,718	84,523	23,806	76	390	141
Revisions of previous estimates	2,290	(13,009)	122	2,290	(13,009)	122	—	—	—
Extensions and discoveries	2,703	4,393	3,435	2,326	1,837	2,632	377	2,556	803
Production	(568)	(4,222)	(1,272)	(554)	(4,160)	(1,247)	(14)	(62)	(25)
Balance at December 31, 2011	14,219	72,075	26,232	13,780	69,191	25,313	439	2,884	919
Revisions of previous estimates	1,574	(7,470)	328	1,774	(5,786)	809	(200)	(1,684)	(481)
Extensions and discoveries	5,809	6,983	6,973	5,809	6,983	6,973	—	—	—
Purchases of minerals in place	1	69	13	1	69	13	—	—	—
Sales of minerals in place	(850)	(6,376)	(1,913)	(850)	(6,376)	(1,913)	—	—	—
Production	(797)	(4,097)	(1,481)	(763)	(3,982)	(1,427)	(34)	(115)	(54)
Balance at December 31, 2012	19,956	61,184	30,152	19,751	60,099	29,768	205	1,085	384

	Total			United States			Canada		
	Oil/ NGL	Gas	Oil Equivalents	Oil/ NGL	Gas	Oil Equivalents	Oil/ NGL	Gas	Oil Equivalents
	(MBbl)	(MMcf)	(MBoe)	(MBbl)	(MMcf)	(MBoe)	(MBbl)	(MMcf)	(MBoe)
	(In thousands)								
Proved Developed Reserves:									
December 31, 2010	5,862	42,750	12,987	5,786	42,360	12,846	76	390	141
December 31, 2011	7,761	42,582	14,858	7,433	40,451	14,175	328	2,131	683
December 31, 2012	8,650	41,220	15,520	8,531	40,723	15,318	119	497	202
Proved Undeveloped Reserves:									
December 31, 2010	3,932	42,163	10,959	3,932	42,163	10,959	—	—	—
December 31, 2011	6,460	29,493	11,376	6,348	28,740	11,138	112	753	238
December 31, 2012	11,306	19,964	14,634	11,220	19,376	14,450	86	588	184

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, 2010, 2011 and 2012. The following information has been prepared in accordance with SEC rules and accounting standards based on the 12-month first-day-of-the-month average prices in accordance with provisions of the Financial Accounting Standards Board's Accounting Standards Update No. 2010-03, "Extractive Activities—Oil and Gas (Topic 932)." 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 and net operating losses associated with the properties. Since prices used in the calculation are average prices for 2012, the standardized measure could vary significantly from year to year based on the market conditions that occurred during a given year.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. All reports by DeGolyer and MacNaughton were developed utilizing studies performed DeGolyer and MacNaughton assisted by the Engineering and Operations departments of Abraxas. Reserves are estimated by independent petroleum engineers. The report of DeGolyer and MacNaughton dated February 26, 2013, 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, 2010, 2011 and 2012 were based on studies performed by our independent petroleum engineers assisted by the Engineering and Operations departments of Abraxas. The Engineering department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Engineering is the manager of this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and has 34 years of experience in reserve evaluations. The Vice President of Engineering is a Registered Professional Engineer in the State of Texas. The operations department of Abraxas assisted in the process, and consists of three petroleum engineers with Bachelor degrees in Petroleum Engineering, 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. The table below sets forth the Standardized Measure of our proved oil and gas reserves for the three years ended December 31, 2010, 2011 and 2012:

	Years Ended December 31,								
	2010			2011			2012		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Future cash inflows	$1,020,286	$1,012,829	$ 7,457	$1,471,352	$1,420,013	$ 51,339	$1,784,920	$1,766,515	$18,405
Future production costs	(391,396)	(389,395)	(2,001)	(544,970)	(532,056)	(12,914)	(642,706)	(634,903)	(7,803)
Future development costs	(164,135)	(163,085)	(1,050)	(228,804)	(224,254)	(4,550)	(328,554)	(324,704)	(3,850)
Future income tax expense	—	—	—	(106,839)	(104,279)	(2,560)	(149,625)	(149,625)	—
Future net cash flows	464,755	460,349	4,406	590,739	559,424	31,315	664,035	657,283	6,752
Discount	(267,762)	(266,041)	(1,721)	(321,657)	(310,516)	(11,141)	(385,890)	(383,271)	(2,619)
Standardized Measure of discounted future net cash relating to proved reserves	$ 196,993	$ 194,308	$ 2,685	$ 269,082	$ 248,908	$ 20,174	$ 278,145	$ 274,012	$ 4,133

Form 10-K

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,		
	2010	2011	2012
		(In thousands)	
Standardized Measure, beginning of year	$150,529	$196,993	$269,082
Sales and transfers of oil and gas produced, net of production costs	(32,261)	(37,171)	(37,080)
Net change in prices and development and production costs from prior year	70,311	92,886	60,710
Extensions, discoveries, and improved recovery, less related costs	14,508	47,765	73,236
Sales of minerals in place	(18,868)	—	(20,089)
Purchased of minerals in place	—	—	131
Revisions of previous quantity estimates	9,694	1,329	3,355
Change in timing and other	(11,973)	(23,501)	(88,309)
Change in future income tax expense	—	(28,918)	(9,799)
Accretion of discount	15,053	19,699	26,908
Standardized Measure, end of year	$196,993	$269,082	$278,145

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,		
	2010	2011	2012
Oil (per Bbl)(1)	$79.43	$96.19	$95.14
Gas (per MMbtu)(2)	4.45	4.16	2.86
Oil (per Bbl)(3)	70.72	88.58	88.26
Gas (per MMBtu)(4)	3.91	3.73	2.61
NGL's (per Bbl)(5)	55.60	50.21	36.76

(1) The quoted oil price for the year ended December 31, 2010, 2011 and 2012 is the 12-month average first-day-of-the-month West Texas Intermediate spot price for each month of 2010, 2011 and 2012.

(2) The quoted gas price for the year ended December 31, 2010, 2011 and 2012 is the 12-month average first-day-of-the-month Henry Hub spot price for each month of 2010, 2011 and 2012.

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

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

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

Exhibit Index

10.9 Employment Agreement between Abraxas and Geoffrey R. King (Filed herewith)

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

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

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

31.2 Certification—Chief Financial Officer. (Filed herewith).

32.1 Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).

32.2 Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).

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

CORPORATE INFORMATION

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BDO USA, LLP
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Independent Reservoir Engineers
DeGolyer and MacNaughton
Dallas, Texas

Stock Exchange Listing
The NASDAQ Stock Market
Ticker Symbol: AXAS

Transfer Agent
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Annual Stockholders Meeting
May 14, 2013 at 9:00 a.m. CT
Abraxas Petroleum Corporation
San Antonio, Texas

OFFICERS

Robert L.G. Watson
President / Chief Executive Officer

Geoffrey R. King
Vice President / Chief Financial Officer

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

William H. Wallace
Vice President—Operations

Peter A. Bommer
Vice President—Engineering

Stephen T. Wendel
Vice President—Land and Marketing

G. William Krog, Jr.
Chief Accounting Officer

DIRECTORS

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

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

Franklin A. Burke (Emeritus)
President, Venture Securities Corporation;
President / Chief Executive Officer,
Burke, Lawton, Brewer & Burke
Ambler, Pennsylvania

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

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

W. Dean Karrash[1]
Executive Vice President / Chief Financial Officer,
Burke, Lawton, Brewer & Burke
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Ledyard National Bank
Hanover, New Hampshire

Brian L. Melton[1]
Vice President—Business Development / 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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