



2015 Annual Report
Proxy Statement
Form 10-K

ABRAXAS PETROLEUM CORPORATION

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

Dear Stockholders,

2015 was a challenging year for our industry and Abraxas and, unfortunately, we expect these challenging times for our industry to continue. With that said, we are looking at the current downturn not with fear, but with anticipation, as we view this as an opportunity to make Abraxas even better.

At the time of this writing, we have ceased all drilling and completion activities as we await a more favorable commodity price environment. We are using this downtime to make our existing production and associated operations more efficient. The fruits of these efforts can be seen in the continuous and significant reduction in our per barrel equivalent lease operating expenses in 2015. In addition to managing our lease operating expenses, our management team and senior level employees elected to take significant salary reductions to help counteract the impact of low oil prices on our cash flow. Our focus remains on maintaining our margins by focusing on what we can control, our cost structure. We expect these favorable cost trends to continue into 2016.

With the curtailment of capital expenditures, we are currently generating free cash flow, which we will continue to use to bolster our balance sheet. We also continue to review all non-cash flowing assets in our portfolio. Should these assets garner attractive prices, we plan to divest these assets with potential proceeds to be used to pay down debt. Additionally, we continue to diligently evaluate opportunities to acquire properties in our core areas. Although we have made a number of offers to date without success, we are adhering to our strict policy of not jeopardizing our balance sheet or pursuing a dilutive transaction. We remain confident that the financial stress in our industry will bring forth numerous and more favorably priced opportunities in the near future.

Although 2015 proved to be a challenging year from a commodity price perspective, it was a successful year for Abraxas operationally. In total Abraxas grew production to 5,975 barrels of oil equivalent per day or up 4% over 2014. We started 2015 with four Bakken wells and two Eagle Ford wells drilled and waiting on completion. We completed all of these wells by the summer of 2015. Our Raven Drilling Rig #1 showed increasing efficiencies and drilled a total of nine gross Bakken/Three Forks wells over the course of 2015. Three of these wells on our Ravin Northwest Pad were subsequently completed in November of 2015. The remaining six wells were on our Stenehjem superpad and drilled to total depths of approximately 21,000 feet. Assuming they are completed midyear, we believe Abraxas will show flat or even slight production growth in 2016, all while spending about one third of our anticipated cash flow. After reaching target depth on the six well Stenehjem superpad in late December, 2015, we suspended further drilling operations in North Dakota. Currently, Raven Drilling Rig #1 is undergoing repairs and maintenance which should further increase its efficiency. We will complete this six well inventory and restart Raven Drilling Rig #1 when favorable commodity prices prevail.

Recently, in connection of our belief that worldwide crude oil fundamentals remain challenged, Abraxas elected to layer on and restructure a portion of our oil hedges. We now have 2,500 barrels of oil per day hedged at an average price of approximately \$43 per barrel for the fourth quarter of 2016, 1,908 barrels of oil per day hedged at an average price of approximately \$55 per barrel for 2017 and 1,500 barrels of oil per day hedged at an average price of approximately \$46 per barrel for 2018. These hedges continue to represent significant value to Abraxas in addition to helping to protect our cash flow profile.

Although I remain comfortable with Abraxas' standing, I find the condition of our industry disconcerting. Almost daily, we hear stories of colleagues and friends from our 40 years in this business facing complete financial loss. Our team is proud of what we have accomplished at Abraxas and we are proud to have you as stockholders. Keep the faith. Times will improve and Abraxas will emerge a better company.

Yours very truly,
Robert L. G. Watson
Chairman, President and CEO

ABRAXAS PETROLEUM CORPORATION

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

April 6, 2016

Dear Stockholders:

You are invited to attend the 2016 Annual Meeting of Stockholders of Abraxas Petroleum Corporation to be held on May 10, 2016, at 9:00 a.m., local time, at our corporate office located at 18803 Meisner Drive, San Antonio, Texas 78258. We hope that you will be able to attend the meeting. Matters on which action will be taken at the meeting are explained in detail in the notice and proxy statement following this letter.

The annual report, notice of Annual Meeting, proxy statement and proxy card are enclosed. Proxy cards are being solicited on behalf of our Board of Directors.

Regardless of whether you plan to attend the Annual Meeting, we hope you will read the attached proxy statement carefully and vote your shares by promptly submitting a proxy by signing, dating and returning the enclosed proxy card in the postage-paid envelope provided or by submitting your proxy by telephone or the Internet as soon as possible. Instructions regarding telephone and Internet voting are included on the proxy card or voting instruction form (or, if applicable, your electronic delivery notice). Choosing one of these voting options ensures your representation at the Annual Meeting regardless of whether you attend in person.

If you have any questions or need assistance in voting your shares, please contact our proxy solicitor, Morrow & Co., LLC toll free at (888) 681-0976.

Thank you for your continued support of Abraxas Petroleum Corporation.

Robert L.G. Watson
Chairman of the Board, President,
and Chief Executive Officer

ABRAXAS PETROLEUM CORPORATION

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

**NOTICE OF ANNUAL MEETING OF STOCKHOLDERS
TO BE HELD MAY 10, 2016**

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 10, 2016, at 9:00 a.m., local time, for the following purposes:

- (1) To elect as directors to the Abraxas Board of Directors the three nominees named below for a term of three years:
 - Harold D. Carter
 - Jerry J. Langdon
 - Brian L. Melton
- (2) To ratify the appointment of BDO USA, LLP as Abraxas' independent registered public accounting firm for the year ending December 31, 2016;
- (3) To ratify and correct the Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan;
- (4) To approve, by advisory vote, a resolution on executive compensation; and
- (5) To transact any other business that has been properly brought before the meeting in accordance with the provisions of the Company's Amended and Restated Bylaws.

Your Board recommends that you vote FOR the nominees named in Proposal 1 and FOR Proposals 2, 3 and 4.

We invite you to attend the Annual Meeting in person. Whether or not you expect to attend the Annual Meeting, we urge you to mark, sign, date, and return the enclosed proxy card 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, 2016 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, 2016 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) 681-0976.

By Order of the Board of Directors,

Stephen T. Wendel
SECRETARY

San Antonio, Texas
April 6, 2016

**Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of
Stockholders to be held May 10, 2016**

**This proxy statement and our 2015 Annual Report on Form 10-K are available at
www.abraxaspetroleum.com <http://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) 681-0976

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 2016 Annual Meeting of Stockholders to be held at 9:00 a.m., local time, on May 10, 2016, 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 6, 2016. 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, 2016 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 106,346,001 shares of Abraxas common stock outstanding, which were held by approximately 1,041 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 One, the election of directors, Proposal Three, the ratification and correction of the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Incentive Plan, and Proposal Four, 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 Two, 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 are as follows:

Election of Directors. Each share of our Common Stock is entitled to one vote with respect to the election of directors. The nominees for director who receive the most votes will be elected. Therefore, if you do not vote for a particular nominee or you indicate “withhold authority to vote” for a particular nominee on your proxy card, your abstention will have no effect on the election of directors. To be elected, each director must receive a plurality of the votes cast at the meeting. Non-votes are not considered votes cast “for” or “against” this proposal and will have no effect on the approval to elect directors.

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 of Directors 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, 2016.

Ratification and Correction of the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. Each share of our Common Stock is entitled to one vote with respect to the ratification and correction of the Abraxas Petroleum Corporation 2005 Amended and Restated Employee Long-Term Equity Incentive Plan, which we refer to as the LTIP. 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, 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 Board of Directors recommends a vote “FOR” the ratification and correction of the LTIP.

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 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, 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 resolution on compensation of our named executive officers.

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.proxyvoting.com/axas and following the instructions for Internet voting shown on the enclosed proxy card.
- **Vote by Telephone**, by dialing (800) 730-7360 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 9, 2016.

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 and 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 \$7,500. 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.

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 2016 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 2016 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 2016 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 or call (210) 490-4788, if you are a stockholder of record; or
- notify your broker, if you hold your shares in street name.

PROPOSAL ONE

Election of Directors

Abraxas' Articles of Incorporation divide the Board of Directors into three classes of directors serving staggered three-year terms, with one class to be elected at each annual meeting. At this year's meeting, three Class III directors are to be elected for a term of three years to hold office until the expiration of their term in 2019, or until a successor has been elected and duly qualified. The nominees for Class III director are Harold D. Carter, Jerry J. Langdon and Brian L. Melton. Messrs. Carter, Langdon and Melton are currently directors. 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 2018, the term of the Class II directors expires in 2017 and the term of the Class III directors expires in 2016.

Name and Municipality of Residence	Age	Office	Class
Robert L.G. Watson San Antonio, Texas	65	Chairman of the Board, President and Chief Executive Officer	II
Harold D. Carter Dallas, Texas	77	Director	III
Ralph F. Cox Fort Worth, Texas	83	Director	II
W. Dean Karrash North Wales, Pennsylvania	54	Director	I
Jerry J. Langdon Houston, Texas	64	Director	III
Dennis E. Logue Enfield, New Hampshire	72	Director	II
Brian L. Melton Oklahoma City, Oklahoma	46	Director	III
Paul A. Powell, Jr. Roanoke, Virginia	70	Director	I
Edward P. Russell Stilwell, Kansas	52	Director	I

Director Nominees

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

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 has served on the Board of Directors of Abraxas since May 2013 and currently works as a private investor. Previously, Mr. Langdon was Chief Administrative and Compliance Officer of Energy Transfer Partners, or 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 Reagan and served in that capacity until 1993. For a period of 38 days in 2012 (from May 21, 2012 until June 28, 2012), Mr. Langdon served as Chairman of the Board and Chief Executive Officer of Latitude Solutions, Inc., a company engaged in the development and deployment of water remediation technologies. On November 9, 2012, Latitude Solutions, Inc. filed for bankruptcy protection under the provisions of Chapter 7 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Texas. 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 make him a valuable member of our Board.

Brian L. Melton has served on the Board of Directors of Abraxas since October of 2009. He has served as Vice President of Pipeline Marketing & Business Development for Blueknight Energy Partners (Nasdaq: BKEP), a publicly traded master limited partnership, or MLP, that specializes in providing crude oil and asphalt terminaling, pipeline and transportation services across the U.S., since December 2013. Prior to joining Blueknight, Mr. Melton served as Vice-President of Business Development / Corporate Strategy for Crestwood Equity Partners, L.P. (NYSE: CEQP), Crestwood Midstream Energy Partners, L.P. (NYSE: CMLP), and Inergy, L.P. (NYSE: NRGY) from September 2008 until December 2013. Crestwood and Inergy are publicly-traded MLPs that specialize 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, Marcellus / Utica, Barnett, Fayetteville, Haynesville and Niobrara U.S. shale regions. Prior to joining Inergy in 2008, 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 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.

Directors with Terms Expiring in 2017 and 2018

Robert L.G. Watson, has served as Chairman of the Board, President, Chief Executive Officer and a director of Abraxas since 1977. Prior to forming Abraxas, Mr. Watson held petroleum engineering positions with Tesoro Petroleum Corporation and DeGolyer and MacNaughton. Mr. Watson serves on the Advisory Board of the Bobby Lyle School of Engineering at Southern Methodist University and the Development Board of the University of Texas at San Antonio. 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 were 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 is the 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 thirty 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 (formerly 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 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. Mr. Logue also serves on the board of Hypertherm, a privately-owned company specializing in plasma cutting tools and technology. 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. 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.

Edward P. Russell, a director of Abraxas since October 2009, has served as a Managing Director of Tortoise Capital Advisors, 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 currently serves on the board of Arc Logistics GP LLC, which is the general partner of Arc Logistics Partners LP. 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.

Director Emeritus

Franklin A. Burke, a director emeritus of Abraxas since 2012 and a director of Abraxas from 1992-2012, has previously served as President and Chief Executive Officer of Burke, Lawton, Brewer & Burke, a securities brokerage firm, from 1964 through 2014, as President of Venture Securities Corporation, since 1971, and as President, Director of Research and Portfolio Management of BLB&B Advisors, LLC, from 2006 through 2014. Mr. Burke also previously served 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 was 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 Master's 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.

Mr. Burke serves at the pleasure of the Board and may be terminated as Director Emeritus at any time upon consent of a majority of the Board of Directors. Mr. Burke has 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 Mr. Burke's consent, at any meetings at which he is in attendance, hold an executive session, at which Mr. Burke may not be present. Except for purposes of indemnification, Mr. Burke is not deemed to be a "director" 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 on pages 6 through 8 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 have strong backgrounds in both the oil and gas industry and the financial / banking community.

Meeting Attendance

During the fiscal year ended December 31, 2015, the Board of Directors held four meetings, the Audit Committee held four meetings, the Compensation Committee held two meetings and the Nominating and Corporate Governance Committee held one meeting. During 2015, 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 his service to Abraxas for his 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’ 2015 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 2015, the Audit Committee consisted of Messrs. Melton (Chairman), Karrash, Langdon and Powell. 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 36, more fully describes the activities and responsibilities of the Audit Committee. Geoffrey R. King, our Chief Financial Officer, William G. Krog Jr., our Chief Accounting Officer, and representatives from BDO USA, LLP, the Company’s independent registered public accounting firm, along with all four members of the Company’s audit committee attended 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, to administer its stock option plans, and to annually review and approve all compensation decisions relating to Abraxas’ executive officers. The Compensation Discussion & Analysis, which begins on page 16, more fully describes the activities and responsibilities of the Compensation Committee. The Compensation Committee submits its decisions regarding executive compensation to the independent members of the Board for approval. The agenda for meetings of the Compensation Committee is determined by its Chairman and the meetings are regularly attended by Mr. Watson. At each meeting, the Compensation Committee also meets in executive session. Mr. Cox reports the committee’s recommendations on executive compensation to the Board. The Company’s personnel support the Compensation Committee in its duties and, along with Mr. Watson, may be delegated authority to fulfill certain administrative duties regarding the Company’s compensation programs. The Compensation Committee has authority under its charter to retain, approve fees for and terminate advisors, consultants and agents as it deems necessary to assist in the fulfillment of its responsibilities. In 2014 and 2015, the Compensation Committee engaged Longnecker and Associates, which we refer to as “L&A” or the “Compensation Consultant”, as its independent compensation consultant. 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 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. 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 the Board's 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 2015. No member of the Compensation Committee was at any time during 2015, 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 2015.

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 2016 Abraxas Annual Meeting" beginning on page 43 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, 2016, the number and percentage of outstanding shares of common stock of Abraxas indicated in the following table. Abraxas' Board has adopted stock ownership guidelines. Please read "Executive Compensation – Stock Ownership Guidelines." 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. None of the shares listed below have been pledged as security.

<u>Name of Beneficial Owner</u>	<u>Number of Shares⁽¹⁾</u>	<u>Percentage (%)</u>
Robert L.G. Watson	2,119,097 ⁽²⁾	2.0%
Geoffrey R. King	432,524 ⁽³⁾	*
Lee T. Billingsley	688,719 ⁽⁴⁾	*
Peter A. Bommer	506,193 ⁽⁵⁾	*
G. William Krog, Jr.	255,040 ⁽⁶⁾	*
William H. Wallace	596,474 ⁽⁷⁾	*
Stephen T. Wendel	715,427 ⁽⁸⁾	*
Franklin A. Burke	5,757,934 ⁽⁹⁾	5.4%
Harold D. Carter	328,614 ⁽¹⁰⁾	*
Ralph F. Cox	598,985 ⁽¹¹⁾	*
W. Dean Karrash	93,998 ⁽¹²⁾	*
Jerry J. Langdon	57,648 ⁽¹³⁾	*
Dennis E. Logue	270,313 ⁽¹⁴⁾	*
Brian L. Melton	187,781 ⁽¹⁵⁾	*
Paul A. Powell, Jr.	325,776 ⁽¹⁶⁾	*
Edward P. Russell	172,800 ⁽¹⁷⁾	*
BlackRock Inc.	6,196,968 ⁽¹⁸⁾	5.8%
Biglari Capital Corp.	5,685,170 ⁽¹⁹⁾	5.3%
All Officers and Directors as a Group (16 persons)	13,107,323	12.3%

* Less than 1%

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

(2) Includes 723,374 shares issuable upon exercise of vested options granted pursuant to the LTIP, 27,392 restricted shares subject to vesting and 53,387 shares in a retirement account.

(3) Includes 238,250 shares issuable upon exercise of vested options granted pursuant to the LTIP, 138,185 restricted shares subject to vesting and 13,589 shares in a retirement account.

(4) Includes 309,030 shares issuable upon exercise of vested options granted pursuant to the LTIP, 98,362 restricted shares subject to vesting and 48,790 shares in a retirement account.

(5) Includes 205,025 shares issuable upon exercise of vested options granted pursuant to the LTIP, 202,274 restricted shares subject to vesting and 30,706 shares in a retirement account.

(6) Includes 123,304 shares issuable upon exercise of vested options granted pursuant to the LTIP, 71,610 restricted shares subject to vesting and 22,492 shares in a retirement account.

(7) Includes 311,407 shares issuable upon exercise of vested options granted pursuant to the LTIP, 98,362 restricted shares subject to vesting and 28,257 shares in a retirement account.

(8) Includes 293,317 shares issuable upon exercise of vested options granted pursuant to the LTIP, 98,090 restricted shares subject to vesting and 115,688 shares in a retirement account.

(9) Includes 82,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan, 302,395 shares in a retirement account, 2,946,062 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, 48,512 shares in various trust and guardianship accounts, of which Mr. Burke is a trustee or guardian, 56,722 shares in the Pleasantville Church Foundation, of which Mr. Burke is a director, and 1,762,436 shares managed by BLB&B Advisors, LLC, of which Mr. Burke is a partial owner. Mr. Burke does not have any voting rights with regard to the shares managed by BLB&B Advisors, LLC.

(10) Includes 121,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan, 7,577 shares in a family trust and 42,598 shares in a retirement account.

(11) Includes 181,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(12) Includes 61,000 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(13) Includes 49,000 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(14) Includes 181,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(15) Includes 156,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(16) Includes 176,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan and 27,277 shares in various entities managed by Mr. Powell.

- (17) Includes 156,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.
- (18) Pursuant to information in its amended Schedule 13G dated January 20, 2016, BlackRock Inc. is the parent corporation of the following subsidiaries which own shares of our common stock; BlackRock Advisors, LLC, BlackRock Asset Management Canada Limited, BlackRock Fund Advisors, BlackRock Institutional Trust Company, N.A. and BlackRock Investment Management, LLC. BlackRock Inc. has sole dispositive power over 6,196,968 shares and sole voting power over 6,055,301 shares. The address of BlackRock Inc. is 55 East 52nd Street, New York, NY 10022.
- (19) Pursuant to information in its Schedule 13G dated January 21, 2016, Biglari Capital Corp. (“BCC”) is the general partner of the The Lion Fund L.P. which owns shares of our common stock. Sardar Biglari is the Chairman and Chief Executive Officer of BCC and has investment discretion over the securities owned by The Lion Fund. BCC shares dispositive power over 5,685,170 shares and shares voting power over 5,685,170 shares. The address of BCC is 17802 IH 10 West, Suite 400, San Antonio, Texas 78257.

Equity Compensation Plan Information

The following table gives aggregate information regarding grants under all of Abraxas’ equity compensation plans through December 31, 2015.

<u>Plan Category</u>	<u>Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights</u>	<u>Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights</u>	<u>Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans</u>
Equity compensation plans approved by security holders	6,717,729	\$2.90	2,145,239
Equity compensation plans not approved by security holders	90,000	\$2.06	—

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 2015, 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	65	Chairman of the Board, President and Chief Executive Officer
Geoffrey R. King San Antonio, Texas	35	Vice President – Chief Financial Officer
Lee T. Billingsley San Antonio, Texas	63	Vice President – Exploration
Peter A. Bommer San Antonio, Texas	59	Vice President – Engineering
William H. Wallace Blanco, Texas	58	Vice President – Operations
Stephen T. Wendel San Antonio, Texas	66	Vice President – Land & Marketing and Secretary
G. William Krog, Jr. San Antonio, Texas	62	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 7 for more information.

Geoffrey R. King has served as Vice President – Chief Financial Officer since 2012. Prior to joining Abraxas, Mr. King worked at Van Eck Associates from 2007-2012 as a Senior Energy Analyst with a focus on natural resource equities and commodities. Prior to that he served as an investment banker 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 a Bachelor of Arts 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 to 2007 term. Dr. Billingsley holds three degrees in Geology, a Bachelor of Science and a Doctorate from Texas A&M University and a 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 in 2015 was a group of exploration and production companies identified by L&A.

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, whom we refer to as the named executive officers or NEOs. 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. In December 2014, the Compensation Committee engaged L&A to assist in providing a comprehensive assessment of our executive compensation programs. The Compensation Committee retained the sole authority to select, retain, terminate, and approve fees and other retention terms of the relationship with L&A.

During 2015, the Compensation Consultant performed the following services for the Committee:

- Conducted an evaluation of the total compensation for each of the NEOs;
- Presented information related to current trends and regulatory developments affecting executive compensation programs in our market; and
- Assisted with the analysis and selection of peer group companies for compensation purposes and for comparative total shareholder return purposes.

The Committee periodically approves and adopts, or makes recommendations to the Board regarding 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 the Abraxas Petroleum Corporation Bonus Plan, as amended, which is referred to as the Bonus Plan, and long-term equity based awards granted pursuant to the LTIP, 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 also 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. During 2014 and 2015, we utilized a list of peer companies provided by L&A to analyze our salary structure. L&A identified potential peer candidates based on 1) companies of similar size, 2) other similar companies in the oil and gas exploration industry, and 3) similar operations in comparable geographies. L&A then analyzed each company based on:

- Market capitalization;
- Revenue;
- Assets;
- Enterprise value; and
- Operational similarities.

Using these criteria, L&A has developed the following list of comparable companies: Approach Resources, Inc. (AREX), Callon Petroleum Company (CPE), Clayton Williams Energy, Inc. (CWEI), Comstock Resources, Inc. (CRK), Contango Oil & Gas Company (MCF), Emerald Oil (EOX), Evolution Petroleum Corp. (EPM), Gastar Exploration Inc. (GST), Magnum Hunter Resources Corp. (MHR), Northern Oil and Gas, Inc (NOG), Penn Virginia Corporation (PVA), Swift Energy Co. (SFY), Triangle Petroleum Corporation (TPLM) and Warren Resources Inc. (WRES).

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 2015 are set forth below in the Summary Compensation Table. For 2015, base salaries, paid as cash compensation, were \$1,454,330 with Mr. Watson receiving \$429,330. We believe that the base salaries paid achieved our objectives.

Annual Bonuses. Abraxas' Bonus Plan was initially 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 initially chose, and continue to utilize, 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 risk credit for non-proven reserves, and adjustments for other assets and liabilities. 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 terms of Bonus Plan in effect for 2015, NAV was calculated at 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 Developed Producing Reserves
+	PV-20 Proved Developed Non-Producing Reserves
+	PV-20 Proved Un-developed Reserves
+	PV-30 Probable Reserves
+	Property & Equipment
+	Other Assets
±	Net Working Capital
–	Debt
=	Net Asset Value ("NAV")
÷	Shares Outstanding
=	NAV per share

The proved and probable reserves were 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, 2014 and 2015:

(in thousands)	December 31,	
	2014	2015
PV-10	\$ 637,443	\$197,251
Present value of future income taxes discounted at 10%	(124,886)	—
Standardized measure of discounted future net cash flows	<u>\$ 512,557</u>	<u>\$197,251</u>

The annual bonuses for 2015 were calculated by the percentage increase in the 2015 year-end NAV per share over the 2014 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. To account for risk, Proved Developed Producing Reserves are discounted 10%; Proved Developed Non-Producing Reserves are discounted 20%; Proved Undeveloped Reserves are discounted 20%; Probable Undeveloped Reserves are discounted 30%. 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 by our independent petroleum engineering firm 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 2015, the calculated NAV per share was \$3.51 (utilizing commodity prices as of December 31, 2014 and the development costs included in our reserve report prepared by DeGolyer and MacNaughton) and the calculated NAV per share at the end of 2015 (utilizing commodity prices as of December 31, 2014 and the development costs included in our reserve report prepared by DeGolyer and MacNaughton) was \$5.18, a 47.7% increase equating to a 70.0% bonus.

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 (which would be issued under the LTIP) 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.

Given the currently depressed nature of the oil and gas industry, as well as Abraxas' 2015 stock price and operational performance, the Compensation Committee deferred its decision on paying 2015 bonuses. At this time the Compensation Committee does not expect that 2015 bonuses will be paid unless industry conditions materially improve.

The following table summarizes the bonuses earned and actually paid to our NEOs for 2015:

<u>Name</u>	<u>Base Salary⁽¹⁾</u>	<u>Bonus Award Achieved (Percentage of Salary)⁽²⁾</u>	<u>Maximum Award (Percentage of Salary)</u>	<u>Annual Bonus Earned Under the Annual Bonus Plan</u>	<u>Annual Bonus Paid Under the Annual Bonus Plan</u>
Robert L.G. Watson	\$460,000	70%	70%	\$322,000	\$0
Geoffrey R. King	275,000	70%	70%	192,500	0
Lee T. Billingsley	250,000	70%	70%	175,000	0
Peter A. Bommer	250,000	70%	70%	175,000	0
William H. Wallace	250,000	70%	70%	175,000	0

(1) Base annual salaries in effect for 2015 for Messrs. Watson, King, Bommer and Wallace and Dr. Billingsley. After giving effect to the election to cut salaries by 20%, our named executive officers had the following base salaries:

<u>Name</u>	<u>Base Salary (\$)</u>
Robert L.G. Watson	368,000
Geoffrey R. King	220,000
Lee T. Billingsley	200,000
Peter A. Bommer	200,000
William H. Wallace	200,000

(2) 1% for the first 10%, then 2% for each percent increase over the first 10%.

Long-Term Equity Incentives. Our executive officers are eligible to receive long-term equity incentives under the LTIP.

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, subject to final Board approval, as to such awards. For awards made to Mr. Watson, the Compensation Committee subjectively evaluates Mr. Watson's performance and, in its sole authority, subject to final Board approval, 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 the 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.

LTIP. The LTIP, which was approved by our stockholders at the 2006 annual meeting and amended by our stockholders at the 2008 annual meeting, at a special meeting held on October 5, 2009, at the annual meeting in 2012 and at the annual meeting in 2015, 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.

As of December 31, 2015, a total of 10,600,000 shares of Abraxas common stock were reserved under the LTIP, 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 2015 was \$18,000 for employees under the age of 50 and \$24,000 for employees 50 years of age or older. The Board of Directors has also suggested a cap on the amount (or percentage) of Abraxas common stock that each employee should own in their individual 401(k) account to encourage diversification. The maximum suggested percentage has been set at 20% and each employee is encouraged to reduce his or her ownership of Abraxas common stock in his or her 401(k) account in the event such employee is over the suggested limit.

2016 Compensation Decisions

Base Salaries. Base salaries for 2016 decreased 20% from the starting 2015 base salaries for our named executive officers.

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. 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. Our bonus plan was approved by our stockholders on May 6, 2014.

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 Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“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, 2015 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.

<u>Name and Principal Position</u>	<u>Year</u>	<u>Salary (\$)⁽¹⁾</u>	<u>Bonus (\$)⁽²⁾</u>	<u>Stock Awards (\$)⁽³⁾</u>	<u>Option Awards (\$)⁽⁴⁾</u>	<u>Non-Equity Incentive Plan Compensation (\$)⁽⁵⁾</u>	<u>All Other Compensation (\$)⁽⁶⁾</u>	<u>Total (\$)⁽⁷⁾</u>
Robert L.G. Watson President, Chief Executive Officer and Chairman of the Board	2015	429,330	—	—	690,000	—	9,275	1,128,605
	2014	450,000	17,692	63,000	102,884	322,000	9,100	964,676
	2013	415,000	132,494	8,313	65,156	177,660	8,925	807,548
Geoffrey R. King Vice President—Chief Financial Officer	2015	275,000	—	—	575,000	—	9,275	859,275
	2014	266,250	10,577	410,750	61,507	192,500	9,100	950,684
	2013	237,500	75,711	1,541	37,232	101,520	8,925	462,429
Lee T. Billingsley Vice President—Exploration	2015	250,000	—	—	460,000	—	9,275	719,275
	2014	246,250	9,615	350,250	55,915	175,000	9,100	846,130
	2013	232,750	74,133	3,781	36,456	99,405	8,925	455,450
Peter A. Bommer Vice President—Engineering	2015	250,000	—	—	460,000	—	9,275	719,275
	2014	246,250	9,615	630,000	55,915	175,000	9,100	1,125,880
	2013	230,000	74,133	2,557	36,456	99,405	8,925	451,476
William H. Wallace Vice President—Operations	2015	250,000	—	—	460,000	—	21,275	731,275
	2014	246,250	9,615	350,250	55,915	175,000	21,100	858,130
	2013	232,750	74,133	3,781	36,456	99,405	20,925	467,450

- (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 \$17,692, \$10,577, \$9,615, \$9,615 and \$9,615 awarded to Mr. Watson, Mr. King, Dr. Billingsley, Mr. Bommer and Mr. Wallace, respectively, in 2014, and a one-time discretionary bonus awarded in 2013. No holiday bonuses were paid in 2015.
- (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, 2015 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, 2015 filed with the Securities and Exchange Commission for a discussion of all assumptions made in the calculation of this amount.
- (5) The amounts included in this column for 2013 and 2014 include cash bonuses earned and paid under the annual bonus plan.
- (6) The amounts in this column represent contributions by Abraxas to the named executive officer's 401(k) plan account for 2013, 2014 and 2015 as well as a \$12,000 vehicle allowance for Mr. Wallace in 2013, 2014 and 2015.
- (7) The dollar value in this column for each named executive officer represents the sum of all compensation reflected in the previous columns.

GRANTS OF PLAN-BASED AWARDS

The following table provides information with regard to grants of non-equity incentive compensation and all other stock and option awards to our named executive officers in 2015.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards ⁽¹⁾			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⁾
		Threshold (\$)	Target (\$)	Maximum (\$)				
Robert L.G. Watson	12/31/2015		0	322,000				
	03/03/2015					300,000	3.16	690,000
Geoffrey R. King	12/31/2015		0	192,500				
	03/03/2015					250,000	3.16	575,000
Lee T. Billingsley	12/31/2015		0	175,000				
	03/03/2015					200,000	3.16	460,000
Peter A. Bommer	12/31/2015		0	175,000				
	03/03/2015					200,000	3.16	460,000
William H. Wallace	12/31/2015		0	175,000				
	03/03/2015					200,000	3.16	460,000

(1) Reflects awards payable under our annual bonus plan. The annual bonus plan does not provide for a threshold level as the bonuses under the plan can range from 0 to the maximum, which equals 70% of the named executive officer's base salary. Please see the discussion under "Compensation Discussion and Analysis – Elements of Executive Compensation – Annual Bonuses" for more information.

(2) The amounts in this column reflect the aggregate grant date fair value of stock awards and options granted in 2015 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, 2015 filed with the Securities and Exchange Commission for a discussion of all assumptions made in the calculation of this amount.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

The following table provides information concerning outstanding equity awards at December 31, 2015 for our named executive officers. We do not have an equity incentive compensation plan; therefore, these columns have been omitted from the following table.

Name	OPTION AWARDS				STOCK AWARDS	
	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	41,624	—	3.60	08/28/2017		
	125,000	—	0.99	03/17/2019		
	267,750	—	1.75	10/05/2019		
	90,000	—	2.09	03/16/2020		
	60,000	—	4.72	03/15/2021		
	15,000	5,000	3.74	03/08/2022		
	21,000	21,000	2.39	05/14/2023		
	11,500	34,500	3.15	03/11/2024		
	—	300,000	3.16	03/03/2025		
					27,392	29,036
Geoffrey R. King	150,000	50,000	1.99	09/04/2022		
	12,000	12,000	2.39	05/14/2023		
	6,875	20,625	3.15	03/11/2024		
	—	250,000	3.16	03/03/2025		
					138,185	146,476
Lee T. Billingsley	16,543	—	3.60	08/28/2017		
	50,000	—	0.99	03/17/2019		
	66,937	—	1.75	10/05/2019		
	60,000	—	2.09	03/16/2020		
	30,000	—	4.72	03/15/2021		
	8,475	2,825	3.74	03/08/2022		
	11,750	11,750	2.39	05/14/2023		
	6,250	18,750	3.15	03/11/2024		
	—	200,000	3.16	03/03/2025		
					98,362	104,264
Peter A. Bommer	5,000	—	3.61	09/05/2017		
	7,500	—	0.99	03/17/2019		
	31,875	—	1.75	10/05/2019		
	35,900	—	2.09	03/16/2020		
	15,000	—	4.72	03/15/2021		
	25,000	—	3.55	08/09/2021		
	7,875	2,625	3.74	03/08/2022		
	11,750	11,750	2.39	05/14/2023		
	6,250	18,750	3.15	03/11/2024		
	—	200,000	3.16	03/03/2025		
					202,274	214,410
William H. Wallace	18,920	—	3.60	08/28/2017		
	50,000	—	0.99	03/17/2019		
	66,937	—	1.75	10/05/2019		
	60,000	—	2.09	03/16/2020		
	30,000	—	4.72	03/15/2021		
	8,475	2,825	3.74	03/08/2022		
	11,750	11,750	2.39	05/14/2023		
	6,250	18,750	3.15	03/11/2024		
	—	200,000	3.16	03/03/2025		
					98,362	104,264

(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, 2015 of \$1.06 per share multiplied by the number of shares of stock that had not vested as of December 31, 2015.

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, 2015.

Name	OPTION AWARDS		STOCK AWARDS	
	Number of Shares Acquired on Exercise	Value Realized on Exercise (\$)	Number of Shares Acquired on Vesting	Value Realized on Vesting (\$)
Robert L.G. Watson	—	—	3,696 ⁽¹⁾	6,468
Geoffrey R. King	—	—	12,500 ⁽²⁾	20,625
Lee T. Billingsley	—	—	1,681 ⁽³⁾	2,942
Peter A. Bommer	—	—	7,387 ⁽⁴⁾	12,927
William H. Wallace	—	—	1,681 ⁽⁵⁾	2,942

- (1) These 3,696 stock awards vested on August 9, 2015 and the closing price of Abraxas' common stock on the last trading date before these shares vested (August 7, 2015) was \$1.75.
- (2) These 12,500 stock awards vested on September 4, 2015 and the closing price of Abraxas' common stock on that date was \$1.65.
- (3) These 1,681 stock awards vested on August 9, 2015 and the closing price of Abraxas' common stock on the last trading date before these shares vested (August 7, 2015) was \$1.75.
- (4) 1,137 of these stock awards vested on August 9, 2015 and the closing price of Abraxas' common stock on the last trading date before these shares vested (August 7, 2015) was \$1.75 and 6,250 of these stock awards vested on August 9, 2015 and the closing price of Abraxas' common stock on the last trading date before these shares vested (August 7, 2015) was \$1.75.
- (5) These 1,681 stock awards vested on August 9, 2015 and the closing price of Abraxas' common stock on the last trading date before these shares vested (August 7, 2015) was \$1.75.

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, 2015, 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, 2015, the market value of Abraxas common stock was \$1.06 per share. As an example, Mr. Watson, our chief executive officer, is required to own 2,169,811 shares of Abraxas common stock to meet the stock ownership guidelines at this price. As of December 31, 2015, no officers and one director 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, 2016, 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, 2016, 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 an officer or any extension thereof, such 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 agreement, 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, 2015, our named officers held 1,392,900 unvested options, none of which were "in-the-money". Additionally, our named executive officers held 564,575 shares of restricted stock, all of 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, 2015.

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	460,000	1,375,400	—	—	460,000
	Option acceleration		8,750		8,750	8,750
	Restricted stock acceleration		29,036		29,036	29,036
	Total	460,000	1,413,186		37,786	497,786
Geoffrey R. King	Severance pay	—	825,000	—	—	825,000
	Option acceleration		—		—	—
	Restricted stock acceleration		146,476		146,476	146,476
	Total		971,476		146,476	971,476
Lee T. Billingsley	Severance pay	—	750,000	—	—	750,000
	Option acceleration		3,500		3,500	3,500
	Restricted stock acceleration		104,264		104,264	104,264
	Total		857,764		107,764	857,764
Peter A. Bommer	Severance pay	—	750,000	—		750,000
	Option acceleration		525		525	525
	Restricted stock acceleration		214,410		214,410	214,410
	Total		964,935		214,935	964,935
William H. Wallace	Severance pay	—	750,000	—	—	750,000
	Option acceleration		3,500		3,500	3,500
	Restricted stock acceleration		104,264		104,264	104,264
	Total		857,764		107,764	857,764

(1) These amounts reflect a lump sum payment equal to the officer's annual base salary in effect for 2015.

(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 in effect for 2015. The amounts on the option acceleration row reflect 182,500 "in-the-money" unvested options for the named officers at an average potential value of \$0.07 per share (the difference between the fair market value on December 31, 2015 and the exercise price of the options). Our named executive officers held 466,213 shares of restricted stock valued at the fair market value as of December 31, 2015.

(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 in effect for 2015. and would be paid over the extension period. The amounts on the option acceleration row reflect 182,500 "in-the-money" unvested options for the named officers at an average

potential value of \$0.07 per share (the difference between the fair market value on December 31, 2015 and the exercise price of the options). Our named officers held 466,213 shares of restricted stock valued at the fair market value as of December 31, 2015.

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 2015, the annual retainer fee paid to each director was \$40,000 to be paid in four quarterly cash payments, in addition to reimbursement for travel expenses to attend the quarterly meetings.

During 2015, 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 \$0.99 to \$5.38 per share. Each year at the first regular board meeting following the annual meeting, Abraxas awards each director 25,000 options, in accordance with the terms of the Amended and Restated 2005 Non-Employee Directors Long-Term Equity Incentive Plan, or Directors Plan. The Directors Plan reserves 1,900,000 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 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, 2015 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

<u>Name</u>	<u>Fees Earned or Paid in Cash (\$)⁽¹⁾</u>	<u>Option Awards (\$)⁽²⁾</u>	<u>Total (\$)⁽³⁾</u>
Harold D. Carter	47,500	70,750	118,250
Ralph F. Cox	53,900	70,750	124,650
W. Dean Karrash	50,800	70,750	121,550
Jerry J. Langdon	50,700	70,750	121,450
Dennis E. Logue	49,000	70,750	119,750
Brian L. Melton	59,600	70,750	130,350
Paul A. Powell, Jr.	50,880	70,750	121,550
Edward P. Russell	46,400	70,750	117,150

(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 2015 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, 2015 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.

The following table provides information concerning outstanding equity awards at December 31, 2015 for our directors:

Outstanding Equity Awards at Fiscal Year End Table

<u>Name</u>	OPTION AWARDS		
	Number of Securities Underlying Unexercised Options (Exercisable)	Number of Securities Underlying Unexercised Options (Unexercisable)⁽¹⁾	Option Exercise Price (\$)
Harold D. Carter	10,000		2.75
	10,000		4.51
	10,000		4.32
	10,000		4.50
	10,000		2.36
	10,500		4.13
	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66
Ralph F. Cox	10,000		2.75
	10,000		4.51
	10,000		4.32
	10,000		4.50
	50,000		0.99
	10,000		1.06
	10,000		2.36
	10,500		4.13
	12,000		2.90
	12,000		2.39
W. Dean Karrash	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66
Jerry J. Langdon	12,000		2.39
	12,000		5.38
	25,000		3.66
Dennis E. Logue	10,000		2.75
	10,000		4.51
	10,000		4.32
	10,000		4.50
	50,000		0.99
	10,000		1.06
	10,000		2.36
	10,500		4.13
	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66
Brian L. Melton	75,000		1.64
	10,000		2.36
	10,500		4.13
	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66

Name	OPTION AWARDS		
	Number of Securities Underlying Unexercised Options (Exercisable)	Number of Securities Underlying Unexercised Options (Unexercisable) ⁽¹⁾	Option Exercise Price (\$)
Paul A. Powell, Jr.	10,000		2.75
	45,000		4.59
	10,000		4.51
	10,000		4.32
	10,000		4.50
	10,000		1.06
	10,000		2.36
	10,500		4.13
	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66
Edward P. Russell	75,000		1.64
	10,000		2.36
	10,500		4.13
	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66

(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.

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 2015

There were no related party transactions during 2015.

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, 2016. 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, 2015. 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, 2016.

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 Public Company Accounting Oversight Board ("PCAOB") Auditing Standards 16.
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, 2015, and for filing with the Securities and Exchange Commission.

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

Brian L. Melton, Chairman
W. Dean Karrash
Jerry J. Langdon
Paul A. Powell, Jr.

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, 2015 and December 31, 2014 and the reviews of the condensed consolidated financial statements included in Abraxas' quarterly reports on Form 10-Q for the years ended December 31, 2015 and December 31, 2014, were \$448,000 and \$484,300, 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, 2015 and December 31, 2014, 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, 2015 and December 31, 2014, were \$179,229 and \$187,210, 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, 2015 and December 31, 2014, 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 registered public accounting firm is required to periodically report to the Audit Committee regarding the extent of services provided by the independent registered public accounting firm 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

RATIFICATION AND CORRECTION OF LTIP

General

On September 13, 2005, subject to stockholder approval, the Board adopted the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan, or LTIP, which was approved by our stockholders at the 2006 annual meeting and amended by our stockholders at the 2008 annual meeting.

On June 29, 2009, the Board amended the LTIP, subject to stockholder approval, to increase the number of shares of common stock reserved for issuance under the LTIP to 5,200,000 shares, which was approved on October 5, 2009.

On March 9, 2012, the Board amended the LTIP, subject to stockholder approval, to increase the number of shares of common stock reserved for issuance under the LTIP to 9,200,000 shares, which was approved on May 4, 2012.

On March 3, 2015, the Board amended and restated the LTIP, subject to stockholder approval, to increase the number of shares of common stock reserved for issuance under the LTIP by 1,400,000 shares, which was approved on May 5, 2015. Due to a clerical mistake in the proxy statement for our annual meeting in 2015, the number of shares reserved for issuance under the LTIP was incorrectly stated as 6,600,000 shares, which was less than the 9,200,000 shares previously approved for issuance by the stockholders in 2012. The Board had intended that a total of 10,600,000 shares be reserved for issuance under the LTIP when it approved the increase in 2015. The clerical error only pertains to the total number of shares reserved for issuance under the LTIP. The share amounts listed in the Equity Compensation Plan Information table on page 14 of the 2015 proxy statement were correct and do not need to be updated. Also, please note, the share amounts in the Equity Compensation Plan Information table on page 14 of this proxy statement reflect the 1,400,000 additional shares that were approved last year.

Upon discovering this mistake, it was determined that we should seek the affirmative vote of the stockholders to ratify that a total of 10,600,000 shares are reserved for issuance under the LTIP and to correct the LTIP as it appeared in our proxy statement for the 2015 annual meeting to reflect that a total of 10,600,000 shares are reserved for issuance under the LTIP. *We are not seeking approval for the reservation of additional shares under the LTIP but rather the ratification of the number of shares previously approved by the stockholders in 2012 and 2015 and the correction of the LTIP as it appeared in our proxy statement for the 2015 annual meeting.*

Purpose of the LTIP

The Abraxas Petroleum Board believes that the purpose of the LTIP is to employ and retain qualified and competent personnel and promote the growth and success of Abraxas Petroleum by aligning the long-term interests of Abraxas Petroleum's key employees with those of Abraxas Petroleum's stockholders by providing an opportunity to acquire an interest in Abraxas Petroleum and by providing both rewards for exceptional performance and long-term incentives for future contributions to the success of Abraxas Petroleum. Abraxas Petroleum believes that this purpose will be furthered through the granting of awards, as authorized under the LTIP, so that such key employees will be encouraged and enabled to acquire a substantial personal interest in the continued success of Abraxas Petroleum. Abraxas Petroleum believes the additional shares to be reserved pursuant to the amendment to the LTIP are necessary for Abraxas Petroleum to continue its policy of emphasizing equity compensation and to remain competitive with industry equity grant practices. In lieu of granting long-term incentives under the LTIP, the Board would consider other alternatives to compensate employees.

The 10,600,000 shares reserved for issuance under the LTIP contribute a potential dilution of approximately 8.9%. This potential dilution was calculated by adding (i) the total number of shares available for issuance under the LTIP (10,600,000), (ii) the total number of shares available for issuance under the Directors Plan, and (iii) all unvested shares and unexercised stock options previously awarded and outstanding under the Company's prior equity incentive plans; divided by the total number of shares of outstanding common stock of the Company. Based on information received from the Compensation Committee's independent consultant, L&A, we believe a potential dilution of 8.9% approximates the median dilution of other companies in our peer group. The Company anticipates that the number of shares reserved for issuance under the LTIP will be sufficient to meet the needs of our long-term incentive program for at least two years.

Vote required

Approval of the ratification and correction of the LTIP requires the affirmative vote of the holders of a majority of the shares of Abraxas Petroleum common stock present or represented by proxy and entitled to vote at the annual meeting.

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.

Summary of the LTIP

The following summary of the LTIP is qualified in its entirety by the full text of the LTIP as set forth in Annex A to this proxy statement.

Administration and Eligibility. The LTIP is administered by the Compensation Committee of the Board and authorizes the Board to grant non-qualified stock options, incentive stock options or issue shares of restricted stock to those persons who are employees of Abraxas Petroleum. As of March 10, 2016, Abraxas Petroleum had 99 full-time employees, all of whom are eligible to participate in the LTIP.

Shares Reserved and Awards. The LTIP reserves 10,600,000 shares of Abraxas Petroleum common stock, subject to adjustment following certain events, as discussed below. The maximum annual award for any one employee is 500,000 shares of Abraxas Petroleum common stock. If options, as opposed to restricted stock, are awarded, the exercise share 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 Petroleum. Under this circumstance, the exercise share 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.

Option Exercise. An option is exercised when proper notice of exercise has been given to Abraxas Petroleum, or the brokerage firm or firms approved by Abraxas Petroleum, if any, to facilitate exercises and sales under the LTIP and full cash payment for the shares with respect to which the option is exercised has been received by Abraxas Petroleum or the brokerage firm or firms, as applicable.

Stockholder Rights. Except as otherwise provided in the LTIP, until the issuance of the share certificates evidencing the award shares, no right to vote or receive dividends or any other rights as a stockholder shall exist with respect to the award shares.

Transferability of Awards. An award may not be sold, pledged, assigned, hypothecated, transferred, or disposed of in exchange for consideration, except that an award may be transferred by will or by the laws of descent or distribution and may be exercised, during the lifetime of the employee, only by the employee, unless the Compensation Committee permits further transferability, on a general or specific basis, in which case the Compensation Committee may impose conditions and limitations on any permitted transferability.

Termination of Awards. Unless otherwise provided in the applicable award agreement, vested options granted under the LTIP will expire and cease to be exercisable as follows:

- three (3) months after the date of the termination of the employee, other than in circumstances covered by the following three circumstances;
- immediately upon termination of the employee for misconduct;
- twelve (12) months after the date of the termination of the employee if such termination was by reason of disability; and
- twelve (12) months after the date of the death of the employee.

U.S. Federal Tax Consequences

The following discussion summarizes the material federal income tax consequences of participation in the LTIP. This discussion is general in nature and does not address issues related to the tax circumstances of any particular employee. The discussion is based on federal income tax laws in effect on the date hereof and is, therefore, subject to possible future changes in law. This discussion does not address state, local and foreign tax consequences.

Stock Options. In general, the grant of an option will not be a taxable event to the recipient and it will not result in a deduction to Abraxas Petroleum. The tax consequences associated with the exercise of an option and the subsequent

disposition of shares of common stock acquired on the exercise of such option depend on whether the option is a nonqualified stock option or an incentive stock option.

Upon the exercise of a nonqualified stock option, the participant will recognize ordinary taxable income equal to the excess of the fair market value of the shares of common stock received upon exercise over the exercise price. Abraxas Petroleum will generally be able to claim a deduction in an equivalent amount. Any gain or loss upon a subsequent sale or exchange of the shares of common stock will be capital gain or loss, long-term or short-term, depending on the holding period for the shares of common stock.

Generally, a participant will not recognize ordinary taxable income at the time of exercise of an incentive stock option and no deduction will be available to Abraxas Petroleum, provided the option is exercised while the participant is an employee or within three months following termination of employment (longer, in the case of disability or death). If an incentive stock option granted under the LTIP is exercised after these periods, the exercise will be treated for federal income tax purposes as the exercise of a nonqualified stock option. Also, an incentive stock option granted under the LTIP will be treated as a nonqualified stock option to the extent it (together with other incentive stock options granted to the participant by Abraxas Petroleum) first becomes exercisable in any calendar year for shares of common stock having a fair market value, determined as of the date of grant, in excess of \$100,000.

If shares of common stock acquired upon exercise of an incentive stock option are sold or exchanged more than one year after the date of exercise and more than two years after the date of grant of the option, the participant will not recognize ordinary income in connection with such sale or exchange, and any gain or loss will be long-term capital gain or loss. If shares of common stock acquired upon exercise of an incentive stock option are disposed of prior to the expiration of these one-year or two-year holding periods (a "Disqualifying Disposition"), the participant will recognize ordinary income at the time of disposition, and Abraxas Petroleum will generally be entitled to a deduction, in an amount equal to the excess of the fair market value of the shares of common stock at the date of exercise over the exercise price. Any additional gain following the date of exercise will be treated as capital gain, long-term or short-term, depending on how long the shares of common stock have been held. Where shares of common stock are sold or exchanged in a Disqualifying Disposition (other than certain related party transactions) for an amount less than their fair market value at the date of exercise, any ordinary income recognized in connection with the Disqualifying Disposition will be limited to the amount of gain, if any, recognized in the sale or exchange, and any loss will be a long-term or short-term capital loss, depending on how long the shares of common stock have been held.

If an option is exercised through the use of shares of common stock previously owned by the participant, such exercise generally will not be considered a taxable disposition of the previously owned shares and, thus, no gain or loss will be recognized with respect to such previously owned shares upon such exercise. The amount of any built-in gain on the previously owned shares generally will not be recognized until the new shares acquired on the option exercise are disposed of in a sale or other taxable transaction.

Although the exercise of an incentive stock option as described above would not produce ordinary taxable income to the participant, it would result in an increase in the participant's alternative minimum taxable income and may result in an alternative minimum tax liability.

Restricted Shares. A participant who receives restricted shares will generally recognize ordinary income at the time that they "vest", *i.e.*, when they are not subject to a substantial risk of forfeiture. The amount of ordinary income so recognized will generally be the fair market value of the common stock at the time the shares vest, less the amount, if any, paid for the shares. This amount is generally deductible for federal income tax purposes by Abraxas Petroleum. Dividends paid with respect to common stock that is nonvested will be ordinary compensation income to the participant (and generally deductible by Abraxas Petroleum). Any gain or loss upon a subsequent sale or exchange of the shares of common stock, measured by the difference between the sale price and the fair market value on the date the shares vest, will be capital gain or loss, long-term or short-term, depending on the holding period for the shares of common stock. The holding period for this purpose will begin on the date following the date the shares vest.

In lieu of the treatment described above, a participant may elect to recognize income under Section 83(b) of the Internal Revenue Code in the year of grant of such restricted shares. In such event, the participant will recognize income in the amount of the fair market value of the restricted shares at the time of grant (determined without regard to any restrictions other than restrictions which by their terms will never lapse), less the amount, if any, paid for the shares and Abraxas Petroleum will generally be entitled to a corresponding deduction. Dividends paid with respect to shares as to which a proper

Section 83(b) election has been made will not be deductible to Abraxas Petroleum. If a Section 83(b) election is made and the restricted shares are subsequently forfeited, the participant will not be entitled to any offsetting tax deduction, and will recognize a loss equal to the excess (if any) of the amount paid for such shares (if any) and the amount realized upon such forfeiture (if any).

Amendments. The Board or the Compensation Committee may amend or terminate the LTIP from time to time in such respects as the Board may deem advisable (including, but not limited to, amendments which the Board deems appropriate to enhance Abraxas Petroleum's ability to claim deductions related to stock option exercises); provided, that to the extent an amendment to the LTIP increases the maximum number of shares available under the plan, changes the class of individuals eligible to receive awards under the plan, or requires stockholder approval under the rules of the NASDAQ, such other exchange upon which Abraxas Petroleum common stock is either quoted or traded, or the SEC, stockholder approval shall be required for any such amendment of the LTIP. Subject to the foregoing, it is specifically intended that the Board or Compensation Committee may amend the LTIP without stockholder approval to comply with legal, regulatory and listing requirements and to avoid unanticipated consequences deemed by the Committee to be inconsistent with the purpose of the LTIP or any award agreement.

Adjustments. If the outstanding shares of Abraxas Petroleum's common stock shall be changed into or exchanged for a different number or kind of shares of stock or other securities or property of Abraxas Petroleum or of another corporation, or if the number of such shares of common stock shall be increased by a stock dividend or stock split, there shall be substituted for or added to each share of common stock reserved for the purposes of the LTIP, whether or not such shares are at the time subject to outstanding awards, the number and kind of shares of stock or other securities or property into which each outstanding share of common stock shall be so changed or for which it shall be so exchanged, or to which each such share shall be entitled, as the case may be. Outstanding awards shall also be considered to be appropriately amended as to price and other terms as may be necessary or appropriate to reflect the foregoing events. If there shall be any other change in the number or kind of the outstanding shares of Abraxas Petroleum's common stock, or of any stock or other securities or property into which such common stock shall have been changed, or for which it has been exchanged, and if the Compensation Committee shall in its sole discretion determine that such change equitably requires an adjustment in the number or kind or price of the shares then reserved for the purposes of the LTIP, or in any award previously granted or which may be granted under the LTIP, then such adjustment shall be made by the Compensation Committee and shall be effective and binding for all purposes of the LTIP.

In addition, the Compensation Committee shall have the power, in the event of any merger or consolidation involving Abraxas Petroleum to amend all outstanding awards to permit the exercise thereof in whole or in part at any time, or from time to time, prior to the effective date of any such merger or consolidation and to terminate each such award as of such effective date.

Effectiveness. The LTIP is effective until May 5, 2025 or until terminated under the terms of the plan or extended by an amendment approved by Abraxas stockholders.

Votes Required. Assuming the presence of a quorum, the affirmative vote of the holders of a majority of the shares of common stock present in person or by proxy and entitled to vote on this item at the annual meeting is necessary to ratify and correct the LTIP. The enclosed form of proxy provides a means for stockholders to vote for the ratification and correction of the LTIP, 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 and correction of the LTIP. Under applicable Nevada law, in determining whether this item has received the requisite number of affirmative votes, abstentions and broker non-votes will not be counted and will have no effect.

The Board recommends that you vote "FOR" the ratification and correction of the LTIP.

PROPOSAL FOUR

ADVISORY VOTE ON EXECUTIVE COMPENSATION

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

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

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

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

RESOLVED: That the stockholders approve, on an advisory basis, the compensation of Abraxas' 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 2017 ABRAXAS ANNUAL MEETING

Abraxas intends to hold its next annual meeting during the second quarter of 2017, according to its normal schedule. In order to be included in the proxy material for the 2017 Annual Meeting, Abraxas must receive eligible proposals from stockholders intended to be presented at the annual meeting on or before December 7, 2016, 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 2017 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 9, 2017 and the close of business on March 11, 2017. 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 (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, the notice must set forth (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 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 2017 Annual Meeting is more than 30 days from May 10, 2017 (the anniversary of the 2016 Annual Meeting), the dates for submission of proposals to be included in the proxy materials and for business to be properly brought before the 2017 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, 2015. 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 6, 2016

ABRAXAS PETROLEUM CORPORATION
AMENDED AND RESTATED
2005 EMPLOYEE LONG-TERM EQUITY INCENTIVE PLAN
(As Amended March 11, 2008, June 29, 2009, March 9, 2012 and March 3, 2015)

ABRAXAS PETROLEUM CORPORATION
Amended and Restated
2005 Employee Long-Term Equity Incentive Plan

PART I
PURPOSE, ADMINISTRATION AND RESERVATION OF SHARES

SECTION 1. Purpose of this Plan. The purposes of this Plan are to (a) employ and retain qualified and competent personnel and (b) promote the growth and success of the Company's and its Subsidiaries' business by (i) aligning the long-term interests of the Company's key employees with those of the Company's stockholders by providing an opportunity to acquire an interest in the Company and (ii) providing rewards for exceptional performance and long-term incentives for future contributions to the success of the Company and its Subsidiaries.

This Plan permits the grant of Non-Qualified Stock Options, Incentive Stock Options or Restricted Stock, at the discretion of the Committee and as reflected in the terms of the Award Agreement. Each Award will be subject to conditions specified in this Plan.

SECTION 2. Definitions. As used herein, the following definitions shall apply:

(a) "Award" means any award or benefit granted under this Plan, including Options and Restricted Stock.

(b) "Award Agreement" means a written or electronic agreement between the Company and the Participant setting forth the terms of the Award.

(c) "Beneficial Ownership" has the meaning set forth in Rule 13d-3 promulgated under the Exchange Act.

(d) "Board" means the Company's Board of Directors.

(e) "Change of Control" means the first day that any one or more of the following conditions has been satisfied:

(i) the sale, transfer, or assignment to, or other acquisition by any other entity or entities (other than a Subsidiary), of all or substantially all of the Company's assets and business in one or a series of related transactions;

(ii) a third person, including a "group" as determined in accordance with Section 13(d) or 14(d) of the Exchange Act, obtains the Beneficial Ownership of Common Stock having thirty percent (30%) or more of the then total number of votes that may be cast for the election of members of the Board; or

(iii) during any 12-consecutive month period, the individuals who, at the beginning of such period, constitute the Board ("Incumbent Directors") cease for any reason other than death to constitute at least a majority of the members of the Board; provided, however, that except as set forth in this Section 2(e)(iii), an individual who becomes a member of the Board subsequent to the beginning of the 12-month period, shall be deemed to have satisfied such 12-month requirement and shall be deemed an Incumbent Director if such Director was elected by or on the recommendation of, or with the approval of, at least two-thirds of the Directors who then qualified as Incumbent Directors either actually (because they were Directors at the beginning of such period) or by operation of the provisions of this Section; if any such individual initially assumes office as a result of or in connection with either an actual or threatened solicitation with respect to the election of Directors (as such terms are used in Rule 14a-12(c) of Regulation 14A promulgated under the Exchange Act) or other actual or threatened solicitations of proxies or consents by or on behalf of a person other than the Board, then such individual shall not be considered an Incumbent Director; or

(iv) a merger, consolidation, reorganization or other business combination (a "Transaction"), as a result of which the shareholders of the Company immediately prior to such Transaction own directly or indirectly immediately following such Transaction less than 50% of the combined voting power of the outstanding voting securities of the entity resulting from such Transaction.

(f) "Change in Control Value" has the meaning set forth in Section 5(b).

(g) "Code" means the Internal Revenue Code of 1986, as amended.

(h) "Committee" means the Compensation Committee appointed by the Board, which shall be comprised of two or more outside Directors (within the meaning of the term "outside directors" as used in section 162(m) of the Code, and applicable

interpretive authority under the Code, and within the meaning of “Non-Employee Director” under SEC Rule 16b-3 promulgated under the Exchange Act and who meet any other qualifications required by the applicable stock exchange on which the Common Stock is traded).

(i) “Common Stock” means the common stock of the Company, par value \$.01 per share.

(j) “Company” means Abraxas Petroleum Corporation, a Nevada corporation and any successor thereto.

(k) “Director” means a member of the Board.

(l) “Effective Date” means the date on which the Company’s stockholders have approved this Plan in accordance with applicable NASDAQ rules, or the rules of such other exchange upon which the Company’s Common Stock is then either quoted or traded.

(m) “Exchange Act” means the Securities Exchange Act of 1934, as amended.

(n) “Fair Market Value” means the closing price per share of the Common Stock on the NASDAQ as to the date specified (or the previous trading day if the date specified is a day on which no trading occurred), or if the NASDAQ shall cease to be the principal exchange or quotation system upon which the shares of Common Stock are listed or quoted, then such exchange or quotation system upon which the Company elects to list or quote its shares of Common Stock.

(o) “Incentive Stock Option” means any Option intended to qualify as an incentive stock option within the meaning of Section 422 of the Code.

(p) “Incumbent Director” has the meaning set forth in Section 2(e)(iii).

(q) “Misconduct” means the termination of employment for “cause” as defined in Participant’s employment agreement or in the absence of such an agreement or such a definition, “Misconduct” will mean a determination by the Committee that Participant (i) has engaged in personal dishonesty, willful violation of any law, rule, or regulation (other than minor traffic violations or similar offenses), or breach of fiduciary duty involving personal profit, (ii) is unable to satisfactorily perform or has failed to satisfactorily perform Participant’s duties and responsibilities for the Company or any affiliate, (iii) has been convicted of, or plead nolo contendere to, any felony or a crime involving moral turpitude, (iv) has engaged in negligence or willful misconduct in the performance of his duties including, but not limited to, willfully refusing without proper legal reason to perform Participant’s duties and responsibilities, (v) has materially breached any corporate policy or code of conduct established by the Company or any affiliate as such policies or codes may be adopted from time to time, (vi) has violated the terms of any confidentiality, nondisclosure, intellectual property, nonsolicitation, noncompetition, proprietary information and inventions, or any other agreement between Participant and the Company related to Participant’s employment, or (vii) has engaged in conduct that is likely to have a deleterious effect on the Company or any affiliate or their legitimate business interests including, but not limited to, their goodwill and public image.

(r) “NASDAQ” shall mean the NASDAQ Stock Market.

(s) “Non-Qualified Stock Option” means an Option that does not qualify or is not intended to qualify as an Incentive Stock Option.

(t) “Option” means a Non-Qualified Stock Option or an Incentive Stock Option granted pursuant to Section 8 of this Plan.

(u) “Optionee” means a Participant who has been granted an Option.

(v) “Participant” means any employee of the Company or any of its Subsidiaries that has been granted an Award.

(w) “Plan” means this Abraxas Petroleum Corporation 2005 Amended and Restated Employee Long-Term Equity Incentive Plan, including any amendments thereto.

(x) “Reprice” or “Repricing” shall mean the adjustment or amendment of the exercise price of Options previously awarded whether through amendment, cancellation, replacement of grants or any other means.

(y) “Restricted Stock” means a grant of Shares pursuant to Section 9 of this Plan.

(z) “SEC” means the Securities and Exchange Commission.

(aa) “Share” means one share of Common Stock, as adjusted in accordance with Section 5 of this Plan.

(bb) “Subsidiary” means a “subsidiary corporation,” whether now or hereafter existing, as defined in Section 424(f) of the Code, a limited liability company, partnership or other entity in which the Company controls fifty percent (50%) or more of the voting power or equity interests, or an entity with respect to which the Company possesses the power, directly or indirectly, to direct or cause the direction of the management and policies of that entity, whether through the Company’s ownership of voting securities, by contract or otherwise.

(cc) “Transaction” has the meaning set forth in Section 2(e)(iv).

SECTION 3. Administration of this Plan.

(a) *Authority.* This Plan shall be administered by the Committee. The Committee has full and exclusive power to administer this Plan on behalf of the Board, subject to such terms and conditions as the Committee may prescribe. Notwithstanding anything herein to the contrary, the Committee’s power to administer this Plan, and actions the Committee takes under this Plan, shall be limited by the provisions set forth in the Committee’s charter, as such charter may be amended from time to time, and the further limitation that certain actions may be subject to review and approval by the full Board and/or stockholders.

(b) *Powers of the Committee.* Subject to the other provisions of this Plan, the Committee has the authority, in its discretion:

(i) to determine the Participants to whom Awards, if any, will be granted hereunder;

(ii) to grant Awards to Participants and to determine the terms and conditions of such Awards, including the determination of the Fair Market Value of the Shares in accordance with Section 2(n), the number of Shares to be represented by each Award and the vesting schedule, the exercise price, the timing of such Awards, and to modify or amend each Award, with the consent of the Participant when required;

(iii) to construe and interpret this Plan and the Awards granted hereunder;

(iv) to prescribe, amend, and rescind rules and regulations relating to this Plan, including the forms of Award Agreements, and manner of acceptance of an Award, such as correcting a defect or supplying any omission, or reconciling any inconsistency so that this Plan or any Award Agreement complies with applicable law, rules, regulations and listing requirements and to avoid unanticipated consequences deemed by the Committee to be inconsistent with the purposes of this Plan or any Award Agreement;

(v) subject to compliance with Section 409A of the Code, to accelerate or defer (with the consent of the Participant) the exercise or vested date of any Award;

(vi) to authorize any person to execute on behalf of the Company any instrument required to effectuate the grant of an Award previously granted by the Committee; and

(vii) to make all other determinations deemed necessary or advisable for the administration of this Plan;

provided, that, no consent of a Participant is necessary under clauses (i) or (v) if a modification, amendment, acceleration, or deferral, in the reasonable judgment of the Committee, confers a benefit on the Participant or is made pursuant to an adjustment in accordance with Section 5.

(c) *Effect of Committee’s Decision.* All decisions, determinations, and interpretations of the Committee shall be final and binding on all Participants, the Company (including its Subsidiaries), any stockholder and all other persons.

(d) *Delegation.* To the extent permitted by the Committee’s charter, as such charter may be amended from time to time, the Committee may delegate its authority and duties under this Plan to one or more persons other than its members to carry out its policies and directives, including the authority to grant Awards, subject to the limitations and guidelines set by the Committee, except that (i) the authority to grant or administer Awards with respect to persons who are subject to Section 16 of the Exchange Act, or to persons who are “covered employees” (within the meaning of Treasury Regulation,

Section 1.162-27(c)(2)), shall not be delegated by the Committee; and (ii) any such delegation shall satisfy any other applicable requirements of Rule 16b-3 of the Exchange Act, or any successor provision. Any action by any such delegate(s) within the scope of such delegation shall be deemed for all purposes to have been taken by the Committee. Any person to whom such authority is granted shall continue to be eligible to receive Awards under this Plan, provided that such Awards are granted directly by the Committee without delegation.

(e) *Compliance with Section 409A.* The parties intend that this Plan and Awards be, at all relevant times, in compliance with (or exempt from) Code Section 409A and all other applicable laws, and this Plan shall be so interpreted and administered. In addition to the general amendment rights of the Company with respect to the Plan, the Company specifically retains the unilateral right (but not the obligation) to make, prospectively or retroactively, any amendment to this Plan or any related document as it deems necessary or desirable to more fully address issues in connection with compliance with (or exemption from) Code Section 409A of and other laws. In no event, however, shall this section or any other provisions of this Plan be construed to require the Company to provide any gross-up for the tax consequences of any provisions of, or payments under, this Plan. The Company and its affiliates shall have no responsibility for tax or legal consequences to any Participant (or beneficiary) resulting from the terms or operation of this Plan.

SECTION 4. Shares Subject to this Plan.

(a) *Reservation of Shares.* The shares of Common Stock reserved under this Plan shall be 10,600,000 shares of Common Stock. If an Award expires, is forfeited or becomes unexercisable for any reason without having been exercised in full, the undelivered Shares which were subject thereto shall, unless this Plan has been terminated, become available for future Awards under this Plan. The Shares may be authorized but unissued or reacquired shares of Common Stock. The Company, during the term of this Plan, will at all times reserve and keep available such number of Shares as shall be sufficient to satisfy the requirements of this Plan.

(b) *Time of Granting Awards.* The date of grant of an Award shall, for all purposes, be the date on which the Company completes the corporate action relating to the grant of such Award and all conditions to the grant have been satisfied, provided that conditions to the exercise of an Award shall not defer the date of grant. Notice of a grant shall be given to each Participant to whom an Award is so granted within a reasonable time after the determination has been made.

(c) *Securities Law Compliance.* Shares shall not be issued pursuant to the exercise of an Award unless the exercise of such Award and the issuance and delivery of such Shares pursuant thereto shall comply with all relevant provisions of law, including without limitation, the Securities Act of 1933, as amended, the Exchange Act, the rules and regulations promulgated under either of such Acts, and the requirements of any stock exchange or quotation system upon which the Shares may then be listed or quoted, and shall be further subject to the approval of counsel for the Company with respect to such compliance.

(d) *Substitutions and Assumptions.* The Board or the Committee has the right to substitute or assume Awards in connection with mergers, reorganizations, separations, or other transactions to which Section 424(a) of the Code applies, provided such substitutions and assumptions are permitted by and in compliance with Sections 409A and 424 of the Code and the regulations promulgated thereunder. The number of Shares reserved pursuant to Section 4(a) may be increased by the corresponding number of Awards assumed and, in the case of a substitution, by the net increase in the number of Shares subject to Awards before and after the substitution.

SECTION 5. Adjustments to Shares Subject to this Plan.

(a) *Adjustments.* If the outstanding shares of Common Stock shall be changed into or exchanged for a different number or kind of shares of stock or other securities or property of the Company or of another corporation (whether by reason of merger, consolidation, recapitalization, reclassification, split up, combination of shares or otherwise), or if the number of such shares of Common Stock shall be increased by a stock dividend or stock split, there shall be substituted for or added to each share of Common Stock theretofore reserved for the purposes of this Plan, whether or not such shares are at the time subject to outstanding Awards, the number and kind of shares of stock or other securities or property into which each outstanding share of Common Stock shall be so changed or for which it shall be so exchanged, or to which each such share shall be entitled, as the case may be. Outstanding Awards shall also be considered to be appropriately amended as to price and other terms as may be necessary or appropriate to reflect the foregoing events. No adjustment pursuant to this Section 5 shall be deemed a Repricing of an Option or any other Award. If there shall be any other change in the number or kind of the outstanding shares of Common Stock, or of any stock or other securities or property into which such Common Stock has

been changed, or for which it has been exchanged, and if the Committee shall in its sole discretion determine that such change equitably requires an adjustment in the number or kind or price of the shares then reserved for the purposes of this Plan, or in any Award theretofore granted or which may be granted under this Plan, then such adjustment shall be made by the Committee and shall be effective and binding for all purposes of the Plan. In making any such substitution or adjustment pursuant to this Section 5, fractional shares may be ignored.

(b) *Amendments.* The Committee has the power, in the event of any Transaction, to (1) amend all outstanding Options to permit the exercise thereof in whole or in part at any time, or from time to time, prior to the effective date of any such merger or consolidation or (2) to terminate each such Option as of such effective date and pay each holder of such Award an amount of cash per share equal to the excess, if any, of the Change in Control Value (as hereinafter defined) of the shares subject to such Option over the exercise price under such Options for such shares. For purposes of this subsection (b), the "Change in Control Value" shall be the per share price paid to stockholders of the Company in the Transaction, provided that in the event that the consideration offered to stockholders of the Company consists of anything other than cash, the Committee will determine, in its sole and absolute discretion, the fair cash equivalent portion of the consideration offered that is other than cash.

(c) *No Other Adjustment.* Except as expressly provided herein, no issuance by the Company of shares of any class, or securities convertible into shares of any class, shall affect, and no adjustment by reason thereof shall be made with respect to, the number or price of shares subject to an Award.

(d) *Limitations under Code Section 409A.* Notwithstanding as otherwise provided in this Section 5, no adjustment or amendment shall be taken under this Section 5 that:

(i) with respect to any Awards that are not subject to Code Section 409A as of the date of such action, would cause such Award to be subject to the requirements of Code Section 409A without satisfying such requirements; or

(ii) with respect to Awards subject to Code Section 409A, would constitute (i) a change in the time and form of payment under such Award, unless consented to by the Participant and otherwise satisfies the requirements of Treasury Regulation §1.409A-2(b), (ii) an acceleration of payment under the Award in prohibition of Code Section 409A(a)(3) and the regulations thereunder, taking into consideration the exceptions provided under Treasury Regulation §1.409A-3(j)(4) for certain accelerations, or (iii) a violation of Code Section 409A not otherwise referenced herein that would trigger adverse tax consequences for the Participant.

PART II

TERMS APPLICABLE TO ALL AWARDS

SECTION 6. General Eligibility and Annual Maximum Award; Procedure for Exercise of Awards; Rights as a Stockholder.

(a) *General Eligibility.* Awards may be granted only to Participants.

(b) *Maximum Annual Participant Award.* The aggregate number of Shares with respect to which an Award or Awards may be granted to any one Participant in any one taxable year of the Company shall not exceed 500,000 shares of Common Stock (subject to adjustment as set forth in Section 5(a)).

(c) *Procedure.* An Award shall be exercised when written or electronic notice of exercise has been given to the Company, or the brokerage firm or firms approved by the Company to facilitate exercises and sales under this Plan, in accordance with the terms of the Award by the person entitled to exercise the Award and full payment for the Shares with respect to which the Award is exercised has been received by the Company or the brokerage firm or firms, as applicable. The notification to the brokerage firm shall be made in accordance with procedures of such brokerage firm approved by the Company. The Company shall issue (or cause to be issued) such share certificate promptly upon exercise of and full payment for the Award. No adjustment will be made for a dividend or other right for which the record date is prior to the date the share certificate is issued, except as provided in Section 5 of this Plan.

(d) *Method of Payment.* The consideration to be paid for any Shares to be issued upon exercise or other required settlement of an Award must be paid by cash, check or wire transfer of immediately available funds.

(e) *Stockholder Rights*. Except as otherwise provided in this Plan, until the issuance (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company) of the share certificate evidencing such Shares, no right to vote or receive dividends or any other rights as a stockholder shall exist with respect to the Shares subject to the Award, notwithstanding the exercise of the Award.

(f) *Non-Transferability of Awards*. An Award may not be sold, pledged, assigned, hypothecated, transferred, or disposed of in exchange for consideration, except that an Award may be transferred by will or by the laws of descent or distribution and may be exercised, during the lifetime of the Participant, only by the Participant; unless the Committee permits further transferability, on a general or specific basis, in which case the Committee may impose conditions and limitations on any permitted transferability.

SECTION 7. Effect of Change of Control. Notwithstanding any other provision in this Plan to the contrary, the following provisions shall apply unless otherwise provided in the most recently executed agreement between the Participant and the Company, or specifically prohibited under applicable laws, including, without limitation, Section 409A of the Code, or by the rules and regulations of any applicable governmental agencies or national securities exchanges or quotation systems.

(a) *Acceleration*. Awards of a Participant shall be Accelerated (as defined in Section 7(b)) upon the occurrence of a Change of Control.

(b) *Definition*. For purposes of this Section 7, Awards of a Participant being “Accelerated” means, with respect to such Participant:

- (i) any and all Options shall become fully vested and immediately exercisable, and shall remain exercisable throughout their entire term; and
- (ii) any restriction periods and restrictions imposed on Restricted Stock shall lapse.

PART III

SPECIFIC TERMS APPLICABLE TO OPTIONS AND STOCK AWARDS

SECTION 8. Grant, Terms and Conditions of Options

(a) *Designation*. Each Option shall be designated in an Award Agreement as either an Incentive Stock Option or a Non-Qualified Stock Option. However, notwithstanding such designations, to the extent that the aggregate Fair Market Value of the Shares with respect to which Options designated as Incentive Stock Options are exercisable for the first time by any Participant during any calendar year (under all plans of the Company) exceeds \$100,000, such excess Options shall be treated as Non-Qualified Stock Options. Options shall be taken into account in the order in which they were granted.

(b) *Term of Options*. The term of each Option shall be established by the Committee in its sole and absolute discretion at the date of grant. However, the term of each Incentive Stock Option shall be no more than 10 years from the date of grant, and, in the case of an Incentive Stock Option granted to a Participant who, at the time the Option is granted, owns Shares representing more than 10% of the voting power of all classes of stock of the Company or any Subsidiary, the term of the Option shall be no more than 5 years from the date of grant.

(c) *Vesting*. Options granted pursuant to this Section 8 shall vest pursuant to the periods, terms and conditions determined by the Committee in its sole discretion. The Committee in its sole and absolute discretion may provide that an Option will be vested or exercisable upon (1) the attainment of one or more performance goals or targets established by the Committee; (2) the Optionee’s continued employment as an Employee with the Company for a specified period of time; (3) the occurrence of any event or the satisfaction of any other condition specified by the Committee in its sole and absolute discretion; or (4) a combination of any of the foregoing. Each Option may, in the sole and absolute discretion of the Committee, have different provisions with respect to vesting and/or exercise of the Option. To the extent Options vest and become exercisable in increments, such Options shall cease vesting as of the termination of such Optionee’s employment for any reason other than death, in which case such Options shall immediately vest in full.

(d) *Exercise Prices.*

(i) The per Share exercise price under an Incentive Stock Option shall be: (A) if granted to a Participant who, at the time of the grant of such Incentive Stock Option, owns shares representing more than 10% of the voting power of all classes of stock of the Company or any Subsidiary, the per Share exercise price shall be no less than 110% of the Fair market Value per Share of the Common Stock on the date the Option is granted, or (B) if granted to any other Participant, the per Share exercise price shall be no less than 100% of the Fair Market Value per Share of the Common Stock on the date the Option is granted.

(ii) The per Share exercise price under a Non-Qualified Stock Option shall be no less than 100% of the Fair Market Value per Share of the Common Stock on the date the Option is granted.

(iii) In no event shall the Board or the Committee be permitted to Reprice an Option after the date of grant without stockholder approval.

(e) *Exercise.* Any Option granted hereunder shall be exercisable at such times and under such conditions as determined by the Committee at the time of grant, as provided in the applicable Award Agreement, and as are permissible under the terms of this Plan. An Option may not be exercised for a fraction of a Share.

(f) *Expiration of Options upon Termination of Employment.* Unless otherwise provided in the applicable Award Agreement as determined by the Committee at the time of grant, in the event Optionee's employment with the Company is terminated, Options granted under this Plan, shall expire and cease to be exercisable as follows:

(i) three (3) months after the date of the termination of Optionee's employment, other than in circumstances covered by (ii), (iii) or (iv) below;

(ii) immediately upon termination of Optionee's employment for Misconduct;

(iii) twelve (12) months after the date of the termination of a Optionee's employment if such termination was by reason of disability (within the meaning of Section 22(e)(3) of the Code); and

(iv) twelve (12) months after the date of the death of a Participant.

(v) Notwithstanding the foregoing in this subsection (f), the Committee has the authority to extend the exercise period of any outstanding Option in circumstances in which it deems such action to be appropriate; provided that in no event shall the termination date be extended beyond the earlier to occur of (x) the expiration date set forth in the Award Agreement and (y) the tenth anniversary of the date that the Award was granted. To the extent that the extension of the expiration date results in an Option no longer qualifying as an Incentive Stock Option, such extension shall not be effective unless Optionee approves the extension and waives any and all claims against the Committee and the Company for any losses resulting from the disqualification of the Incentive Stock Option.

SECTION 9. Grant, Terms and Conditions of Stock Awards.

(a) *Designation.* Restricted Stock may be granted either alone, in addition to, or in tandem with other Awards granted under this Plan. After the Committee determines that it will offer Restricted Stock, it will advise the Participant in writing or electronically, by means of an Award Agreement, of the terms, conditions and restrictions, including vesting, if any, related to the offer, including the number of Shares that the Participant shall be entitled to receive or purchase, the price to be paid, if any, and, if applicable, the time within which the Participant must accept the offer. The offer shall be accepted by execution of an Award Agreement or as otherwise directed by the Committee. The term of each award of Restricted Stock shall be at the discretion of the Committee.

(b) *Vesting.* The Committee shall determine the time or times within which an Award of shares of Restricted Stock may be subject to forfeiture, the vesting schedule and the rights to acceleration thereof, and all other terms and conditions of the Award. The Committee may provide that vesting of such Award will occur upon (1) the attainment of one or more performance goals or targets established by the Committee, which are based on (i) percentage increases in net asset value, (ii) earnings before or after interest, taxes, depreciation, and/or amortization, (iii) general administrative expenses, and (iv) finding costs; (2) the Optionee's continued employment or service with the Company for a specified period of time; (3) the occurrence of any event or the satisfaction of any other condition specified by the Committee in its sole and absolute discretion; or (4) a combination of any of the foregoing. Subject to the applicable provisions of the Award Agreement and this Section 9, upon termination of a Participant's employment for any reason, all Restricted Stock subject to the Award Agreement may vest or be forfeited in accordance with the terms and conditions established by the Committee as specified in the Award Agreement. Each Restricted Stock Award may, in the sole and absolute discretion of the Committee, have different forfeiture and vesting provisions.

PART IV
TERM OF PLAN AND STOCKHOLDER APPROVAL

SECTION 10. Term of Plan. This Plan shall become effective as of the Effective Date and shall continue in effect until the tenth anniversary of the Effective Date or until terminated under Section 11 of this Plan or extended by an amendment approved by the stockholders of the Company pursuant to Section 12.

SECTION 11. Amendment and Termination of this Plan.

(a) *Amendment and Termination.* Subject to compliance with Section 409A of the Code, the Board or the Committee may amend or terminate this Plan from time to time in such respects as the Board may deem advisable (including, but not limited to, amendments which the Board deems appropriate to enhance the Company's ability to claim deductions related to stock option exercises); provided, that to the extent an amendment to this Plan (1) increases the maximum number of shares available under the Plan, (2) changes the class of individuals eligible to receive Awards under the Plan, or (3) requires stockholder approval under the rules of the NASDAQ, such other exchange upon which the Company's Common Stock is either quoted or traded, or the SEC, stockholder approval shall be required for any such amendment of this Plan. Subject to the foregoing, it is specifically intended that the Board or Committee may amend this Plan without stockholder approval to comply with legal, regulatory and listing requirements and to avoid unanticipated consequences deemed by the Committee to be inconsistent with the purpose of this Plan or any Award Agreement.

(b) *Effect of Amendment or Termination.* Any amendment or termination of this Plan shall not impair the rights of Participants under previously-granted Awards and such Awards shall remain in full force and effect as if this Plan had not been so amended or terminated, unless mutually agreed otherwise between the Participant and the Committee, which agreement must be in writing and signed by the Participant and the Company.

SECTION 12. Stockholder Approval. The effectiveness of this Plan is subject to approval by the stockholders of the Company in accordance with applicable NASDAQ rules, or the rules of such other exchange upon which the Company's Common Stock is either quoted or traded at the time the Plan or any amendment becomes effective.

PART V
MISCELLANEOUS

SECTION 13. Unfunded Plan. The adoption of this Plan and any setting aside of amounts by the Company with which to discharge its obligations hereunder shall not be deemed to create a trust. The benefits provided under this Plan shall be a general, unsecured obligation of the Company payable solely from the general assets of the Company, and neither a Participant nor the Participant's beneficiaries or estate has any interest in any assets of the Company by virtue of this Plan. Nothing in this Section 13 shall be construed to prevent the Company from implementing or setting aside funds in a grantor trust subject to the claims of the Company's creditors. Legal and equitable title to any funds set aside, other than any grantor trust subject to the claims of the Company's creditors, shall remain in the Company and any funds so set aside shall remain subject to the general creditors of the Company, present and future. Any liability of the Company to any Participant with respect to an Award shall be based solely upon contractual obligations created by this Plan and the Award Agreements.

SECTION 14. Representations and Legends.

(a) The Committee may require each person purchasing shares pursuant to an Award under this Plan to represent to and agree with the Company in writing that the purchaser is acquiring the shares without a view to distribution thereof. In addition to any legend required by this Plan, the certificate for such shares may include any legend which the Committee deems appropriate to reflect a restriction on transfer.

(b) All certificates for shares of Common Stock delivered under this Plan shall be subject to such stock transfer orders and other restrictions as the Committee may deem advisable under the rules, regulations and other requirements of the SEC, any stock exchange upon which the Common Stock is listed, applicable federal or state securities laws, and any applicable corporate law, and the Committee may cause the legend or legends to be put on any such certificates to make appropriate reference to such restriction.

SECTION 15. Assignment of Benefits. No Award or other benefits payable under this Plan shall, except as otherwise provided under this Plan or as specifically provided by law, be subject in any manner to anticipation, alienation, attachment,

sale, transfer, assignment, pledge, encumbrance or charge. Any attempt to anticipate, alienate, attach, sell, transfer, assign, pledge, encumber or charge, any such benefit shall be void, and any such benefit shall not in any manner be subject to the debts, contracts, liabilities, engagements or torts of any person who shall be entitled to such benefit, nor shall such benefit be subject to attachment or legal process for or against that person.

SECTION 16. Governing Laws. This Plan and actions taken in connection herewith shall be governed, construed and enforced in accordance with the laws of the State of Nevada.

SECTION 17. Application of Funds. The proceeds received by the Company from the sale of shares of Common Stock pursuant to Awards granted under this Plan will be used for general corporate purposes.

SECTION 18. Right of Discharge. Nothing in this Plan or in any Award or Award Agreement shall confer upon any Participant or any other individual the right to continue in the employment or service of the Company or any of its Subsidiaries, or affect any right the Company or any of its Subsidiaries may have to terminate the employment or service of any such Participant or any other individual at any time for any reason.

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, 2015

☐ 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:

Common Stock, par value \$.01 per share

Name of each exchange on which registered:

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, 2015, 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 \$295,066,931 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 10, 2016, there were 106,346,001 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2016 Annual Meeting of Stockholders to be held on May 10, 2016.	Part III

ABRAXAS PETROLEUM CORPORATION
FORM 10-K
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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 “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 prices we receive for our production and the effectiveness of our hedging activities;
- the availability of capital including under our credit facility;
- our success in development, exploitation and exploration activities;
- 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 ability to procure services and equipment for our drilling and completion activities;
- 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.

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:

“Developed oil and gas reserves*” Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

“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 developed reserves*” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“Proved reserves*” Reserves 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 undeveloped reserves” or “PUDs*” Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

“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.”

“Undeveloped oil and gas reserves*” Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see: http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.210&r=PART#se17.3.210_14_610

Part I

Information contained in this report represents the consolidated 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. On October 31, 2014, we closed on the sale of our interest in Canadian Abraxas Petroleum, ULC (“Canadian Abraxas”), an indirect wholly-owned Canadian subsidiary of Abraxas Petroleum Corporation. As a result of the disposal of Canadian Abraxas, the results of operations of Canadian Abraxas are reflected in our Financial Statements and in this report as “Discontinued Operations” and our remaining operations are referred to in our Financial Statements and in this report as “Continuing Operations” or “Continued Operations.” Unless otherwise noted, all disclosures are for Continuing Operations.

Item 1. Business

General

We are an independent energy company primarily engaged in the acquisition, exploration, development and production of oil and gas. At December 31, 2015, our estimated net proved reserves were 43.2 MMBoe, of which 39.8% were classified as proved developed, 71% were oil and NGL and 95% of which (on a PV-10 basis) were operated by us. Our daily net production for the year ended December 31, 2015 was 5,975 Boepd, of which 77% was oil or liquids. Abraxas Petroleum Corporation was incorporated in Nevada in 1990. Our address is 18803 Meisner Drive, San Antonio, Texas 78258 and our phone number is (210) 490-4788.

Our oil and gas assets are located in three operating regions, the Rocky Mountain, Permian Basin and onshore Gulf Coast. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2015:

	Gross Producing Wells	Average Working Interest	Total Net Acres	Estimated Net Proved Reserves		Net Production	
				(MBoe)	% Oil/NGL	(MBoe)	% Oil/NGL
Rocky Mountain	788	11.79%	44,013	29,476	83.9%	1,324.4	85.6%
Permian Basin	240	64.22%	28,370	10,106	40.3%	293.6	44.7%
Onshore Gulf Coast	78	82.71%	14,141	3,608	52.5%	562.8	73.5%
Total United States	1,106	28.17%	86,524	43,190	71.0%	2,180.8	77.0%

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 Uinta Basins of Wyoming and Utah. In this region, our wells produce oil and gas from various reservoirs, primarily the Turner, Bakken, Three Forks and Red River formations. Well depths range from 7,000 feet down to 14,000 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, 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, the Eagle Ford shale in Atascosa and McMullen 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. In the Eagle Ford, our wells produce from the Eagle Ford shale from 8,000 to 11,000 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.

2016 Outlook

Market prices for oil, gas and NGL are inherently volatile. Accordingly, we cannot predict with certainty the future prices for the commodities we produce and sell. Current market fundamentals indicate prices for oil, gas and NGL will

continue to be depressed for much of 2016. Although changes in OPEC production strategies, geopolitical risks or other factors could impact current forecasts, we anticipate weak commodity prices throughout 2016. Depressed prices for oil and gas will likely have a material adverse effect on our results of operations and liquidity. Our primary sources of liquidity are cash flow from operations and borrowings under our credit facility. Cash flow from operations is sensitive to many variables, the most volatile of which is the price of the oil, gas and NGL we produce and sell. Our consolidated cash flow from operations decreased in 2015 as a result of the significant decrease in commodity prices. Availability under our credit facility is currently subject to a borrowing base of \$165.0 million. The borrowing base is subject to scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations. 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. The lenders under our credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Given the ongoing decline in commodity prices for oil, gas and NGL, it is likely that reductions in our borrowing base could arise in 2016.

In 2015, as a result of the sharp decline in commodity prices, we incurred an impairment to our proved properties of \$128.6 million. We expect to record additional impairments of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month average oil and gas prices through March 1, 2016 of \$46.04 per Bbl of oil and \$2.48 per Mcf of gas being held constant for the trailing 12-month period, we estimate that we will record a ceiling test write down on our existing assets of approximately \$30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of \$72.7 million for the remainder of the year ending December 31, 2016. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While we will continue to operate and develop our portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs to be within our cash flow from operations. As a result, we are significantly reducing our capital budget in response to lower commodity prices. We are also committed to reducing our G&A and field-level operating costs commensurate with our reduced, but focused, activity level. Effective February 1, 2016, the named executive officers of Abraxas took a voluntary salary reduction of 20% and other employees, depending on salary thresholds, took voluntary cuts of 10%—20%. It is anticipated that these reductions will reduce G&A cost by approximately \$0.8 million during 2016.

Strategy

Our business strategy is to focus our capital and resources on our core operated basins, maintain financial flexibility and profitably and to 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), which primarily produce oil and liquids, and the Permian Basin and Powder River Basin, which primarily produce gas. Given the disparity which has existed during the past several years and which continues currently between oil and gas prices, the economics of drilling oil wells is far superior to drilling gas wells. Thus, substantially all of our 2016 estimated capital expenditures will be in completing wells which have already been drilled in the Bakken, Three Forks. As part of our efforts to focus our property portfolio, we are continually marketing assets we have deemed non-core. These include assets with a low working interest that are non-operated and/or 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. At December 31, 2015 we had approximately \$31.0 million of availability under our credit facility and for the year ended December 31, 2015, we generated approximately \$7.0 million of cash flow from operations. Availability under our credit facility is subject to a borrowing base which is determined semi-annually by our lenders. The next borrowing base redetermination is scheduled to be effective on April 1, 2016. We seek to reduce the volatility of our cash flow from operations by hedging a portion of our production. We plan on deploying our available capital in a cost-effective manner. We seek to operate a high percentage of our properties which allows us to better control costs. At December 31, 2015, we operated properties comprising 95% of our proved developed reserves on a PV-10 basis. We intend to maintain our liquidity and the strength of our balance sheet during 2016 by adjusting our capital budget and seeking to reduce G&A and other expenses.

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 2015. 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. Cost savings achieved through efficiencies of using 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.

2016 Budget and Drilling Activities

Our capital expenditure budget for 2016 is approximately \$40.0 million. This budget assumes an improvement in commodity prices by the summer of 2016, and re-starting the Raven Rig #1. However, if commodity prices stay at current levels or decline further and we elect to keep the Raven Rig #1 idled, our capital expenditures could be approximately \$17.5 million which we intend to fund primarily with cash flows from operations. Substantially all of the \$17.5 million would be spent on completing previously drilled wells in the Bakken/Three Forks in the Rocky Mountain region. These wells are classified as PDNP at December 31, 2015. The 2016 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources including under our credit facility, 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. Refer to “Risk Factors—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” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies” for more information relating to the effects that decreases in oil and gas prices have 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 and three way collars. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—General—Commodity Prices and Hedging Arrangements” and Note 11 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, 2015, one purchaser of production accounted for approximately 54% of our oil and gas sales. During the year ended December 31, 2014, two purchasers of production accounted for approximately 62% 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. Furthermore, the largest purchasers of our oil and gas have changed from year to year from 2013 to 2015.

Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our properties are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental and other laws relating to the petroleum industry, and by changes in such laws and by periodically changing administrative regulations.

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

Development and Production

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

- the location of wells;
- the method of drilling and casing wells;
- the flaring of gas;
- 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 states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some states allow forced pooling or unitization of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratable 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 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 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 tribal and 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 certain cases. 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 Gas in the United States

Historically, the transportation and sale for resale of 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 gas could be sold. Deregulation of wellhead 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 gas effective January 1, 1993. While sales by producers of gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

Since 1985, FERC has endeavored to make gas transportation more accessible to 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 gas pipeline industry and to create a regulatory framework that will put gas sellers into more direct contractual relations with gas buyers by, among other things, unbundling the sale of 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 gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of 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 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 gas producers, they are intended to foster increased competition within all phases of the 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 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 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 gas marketplace.

The 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 gas producers, gatherers and marketers.

Generally, intrastate gas transportation is subject to regulation by state regulatory agencies, although FERC does regulate the rates, terms, and conditions of service provided by intrastate pipelines that transport gas subject to FERC's NGA jurisdiction pursuant to Section 311 of the NGPA. The basis for state regulation of intrastate gas transportation and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate gas transportation in any states in which we operate and ship 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.

Gas Gathering in the United States

Section 1(b) of the NGA exempts 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 from 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 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 regulations, 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.

All of our oil is sold on lease, at which time custody transfers, either by truck or pipeline. We are not able to determine how much of our oil production is ultimately shipped to market centers using rail transportation facilities owned and operated by third parties. The U.S. Department of Transportation's ("U.S. DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") establishes safety regulations relating to transportation of oil by rail transportation. In addition, third party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the U.S. DOT, the Federal Railroad Administration ("FRA") of the DOT, OSHA, as well as other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and seek to regulate movement of hazardous materials in ways not preempted by federal law.

In response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. Recently, in response to train derailments occurring in 2013, U.S. regulators have been implementing or considering new rules to address the safety risks of transporting oil by rail. On January 23, 2014, the National Transportation Safety Board ("NTSB") issued a series of recommendations to the FRA and PHMSA to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) developing an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) auditing shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the DOT issued an emergency order requiring all persons, prior to offering oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of oil be handled as a Packing Group I or II hazardous material.

We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or handling of shipments of oil by rail transportation could increase our costs of doing business and limit our ability to transport and sell our oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows. At this time, it is not possible to estimate the potential impact on our business if new federal or state rail transportation regulations are enacted.

Environmental Matters

Oil and gas operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, treatment, storage and disposal of materials and the 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;
- impose design and construction requirements on facilities in conjunction with oil and gas operations, including the construction of pollution control devices;

- require protective measures to prevent drilling fluids from coming into contact with ground water;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, and gas processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and 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;
- require disclosure of chemicals injected into wells in conjunction with hydraulic fracturing operations;
- restrict injection of liquids into subsurface strata that may contaminate groundwater;
- restrict the availability of water necessary for hydraulic fracturing operations;
- impose substantial penalties for violations of environmental rules or pollution resulting from our operations; and
- curtail production in association with exceeding gas flaring limits.

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

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

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

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as CERCLA, and comparable state statutes impose strict joint, and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include among others, the current and former owners or operators of a disposal site or sites where a release occurred and companies that arranged for the transportation or 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, and analogous state laws, contain numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. 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 and 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. Analogous state laws further impose requirements associated with the management of solid wastes. 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. We believe that our operations comply in all material respects with the requirements of RCRA and its state counterparts.

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 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. EPA and the U.S. Army Corps of Engineers have adopted a rule that arguably expands the scope of "waters of the United States" that are regulated under the CWA. This rule could impact our operations by subjecting new waters to regulation; however, enforcement of the rule has been stayed while it is undergoing legal challenge in the federal courts. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of 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 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. 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. In addition, subsurface injection of water or other produced fluids from drilling or hydraulic fracturing processes have come under increased public and governmental scrutiny. Some jurisdictions, Texas for example, have adopted new rules for injection wells aimed at reducing the potential for earthquakes associated with injection activities. We currently own and operate various underground injection wells. Failure to comply with 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 and has proposed rules that are still under review, including regulations which impose new restrictions on emissions of methane, volatile organic compounds and hazardous air pollutants.

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

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 of 2015 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. In May 2015 the EPA released its draft report, assessment of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. This report has been under public and EPA review and has not yet been finalized. Also, in March 2015, the U.S. Department of the Interior, Bureau of Land Management (“BLM”) released final regulations, in 2015, concerning hydraulic fracturing on federal and tribal lands, including chemical disclosure. These rules are currently under judicial challenge. 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. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact water available for hydraulic fracturing. 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. Additional information concerning hydraulic fracturing is included under Item 1A. related to risk factors.

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, gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. In December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020. It is possible that the Paris Agreement and subsequent domestic and international regulations will have adverse effects on the market for oil, gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, oil, gas and other fossil fuel products. We are unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions that may arise from the Paris Agreement, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect our operations, financial condition and results of operations. In addition, 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 U.S. 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 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 gas exploration and production industry and the pipeline industry. Moreover, in January 2015, the Obama Administration announced that it would directly regulate methane emissions from the oil and gas industry as part of its climate strategy. Although the announcement gave no details on the upcoming regulations, it warned that the oil and gas sector will need to reduce its methane emissions by 40 to 50 percent from 2012 emission levels by 2025. Subsequently, on September 18, 2015, the EPA proposed three rules and issued a notice of availability of a draft Control Techniques Document relating to air emissions from the oil and gas industry. Further, on November 27, 2015, the EPA requested information related to hazardous air pollutant emissions from oil and gas operations. Additional rules from the EPA, BLM, and Department of Energy are expected under the EPA's methane plan. The EPA's finding, the greenhouse gas reporting rule, the methane plan and the other 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. Finally, some states, either individually or through multi-state regional initiatives, 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. Additional information concerning climate change is included under Item 1A. related to risk factors.

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 species which, if listed, could include habitat in areas where we operate or plan to operate. Further, some of the species could become subject to voluntary rangeland conservation plans that could affect our operations. Such listing of additional species, or the discovery of previously unidentified endangered or threatened species, or the adoption of conservation plans, 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, we cannot assure you that such materials and resources will be available to us in the future.

Employees

As of March 10, 2016, we had 99 full-time employees. We retain independent geological, land, marketing 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

A continued substantial or extended decline in oil and/or gas prices would have a material and adverse effect on us.

Our financial results and the value of our properties are highly dependent on the general supply and demand for oil, gas and NGL, which impact the prices we ultimately realize on our sales of these commodities. Since the second half of 2014, there has been a significant decline in oil, gas and NGL prices, which adversely affected our 2015 operating results and contributed to a reduction in our anticipated future capital expenditures. In addition, this decline in commodity prices has adversely impacted our estimated proved reserves and resulted in a proved property impairment of \$128.6 million to our oil and gas properties during 2015.

We expect to record an additional impairment of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month unweighted average oil and gas prices through March 1, 2016 of \$2.48 per Mcf of gas and \$46.04 per Bbl of oil being held constant for trailing 12-month period, we estimate that, we will record a ceiling test write down on our existing assets of approximately \$30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of \$72.7 million for the remainder of the year ending December 31, 2016. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

A sustained weakness or further deterioration in commodity prices could materially and adversely impact our business by resulting in, or exacerbating, the following effects:

- reducing the amount of oil, gas and NGL that we can produce economically;
- reducing the borrowing base of our credit facility;
- limiting our financial flexibility, liquidity and access to sources of capital, such as equity and debt;
- reducing our revenues, operating cash flows and profitability;
- causing us to further decrease our capital expenditures or maintain reduced capital spending for an extended period, resulting in lower future production of oil, gas and NGL; and
- reducing the carrying value of our properties, resulting in additional noncash write-downs.

Market prices and our realized prices have been volatile and are likely to continue to be volatile in the future due to numerous factors beyond our control. These factors include:

- the level of demand;
- domestic and global supplies of oil, NGL and gas;
- the price and quantity of imported and exported oil, NGL and gas;
- the actions of other oil exporting nations
- weather conditions and changes in weather patterns
- the availability, proximity and capacity of appropriate transportation facilities, gathering, processing and compression facilities, storage facilities and refining facilities;
- worldwide economic and political conditions, including political instability or armed conflict in oil and gas producing regions, competition for markets and political initiatives disfavoring fossil fuels;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the nature and extent of governmental regulation, including environmental regulation, regulation of derivatives transactions and hedging activities, tax laws and regulations and laws and regulations with respect to the import and export of oil, gas and related commodities;

- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others, and;
- the effect of worldwide energy conservation measures.

Our cash flows, the results of operations and the borrowing base under our credit facility depend to a great extent on the prevailing prices for oil and gas. Prolonged or substantial declines in oil and/or gas prices would materially and adversely affect our liquidity, the amount of cash flows we have available for our capital expenditures and other operating expenses, our ability to access the credit and capital markets and our results of operations.

Any significant reduction in the borrowing base under our credit facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our credit facility or any other obligation if required as a result of a borrowing base redetermination

Availability under our credit facility is currently subject to a borrowing base of \$165.0 million. The borrowing base is subject to scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations. 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. The lenders under our credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Given the ongoing decline in commodity prices for oil, gas and NGL, it is likely that reductions in our borrowing base could arise from a number of factors, including:

- a reduction in reserve estimates;
- lower commodity prices or production;
- inability to drill or unfavorable drilling results;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

As of March 15, 2016, we had \$134.0 million of borrowings outstanding under our credit facility. Any significant reduction in our borrowing base as a result of borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our credit facility were to exceed the borrowing base as a result of redetermination, we would be required to repay the excess amount or pledge additional assets. We may not have sufficient funds to make such repayment and we do not have any substantial unpledged assets. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Lower oil and/or gas prices may also reduce the amount of oil and/or gas that we can produce economically.

Sustained substantial declines in oil and/or gas prices may render uneconomic a significant portion of our exploration, development and exploitation projects, which may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a prolonged or substantial decline in oil and/or gas prices such as we have experienced since mid-2014 has caused, and would likely in the future cause, a material and adverse effect on our future business, financial condition, results of operations, liquidity and ability to finance capital expenditures. Additionally, if we experience or continue to experience significant sustained decreases in oil and gas prices such that the expected future cash flows from our oil and gas properties falls below the net book value of our properties, we may be required to write down the value of our oil and gas properties. Any such asset impairments could materially and adversely affect our results of operations and, in turn, the trading price of our common stock.

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

At December 31, 2015, we had a total of \$134.0 million of indebtedness under our credit facility and total indebtedness of \$140.7 million (including the current portion). Our indebtedness could have important consequences to us, including:

- affecting 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 or at all;
- 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 effect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of our credit facility, including borrowings in excess of the borrowing base or 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 further 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.

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, 2014, the net capitalized costs of our oil and gas properties did not exceed the present value of our estimated proved reserves. For 2015, the net capitalized of our oil and gas properties exceeded the present value of our proved reserves, resulting in recognition of impairments in the third and fourth quarters totaling \$128.6 million. If commodity prices remain at depressed levels or decrease further, we would likely be required to write down the carrying value of our reserves during 2016 which would also reduce our net income. Based on the 12-month average oil and gas prices through March 1, 2016 of \$46.04 per Bbl of oil and \$2.48 per Mcf of gas being held constant for the trailing 12-month period we estimate that we will record a ceiling test write down on our existing assets of approximately \$30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of \$72.7 million for the remainder of the year ending December 31, 2016.

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, location to market, 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. In addition, we have a contract related to certain gas and NGL in the Rocky Mountain Region, that if certain margins of gas and NGL prices are not met by the purchaser, we receive no sales proceeds.

During 2015, differentials averaged \$(7.61) per Bbl of oil and \$(0.69) per Mcf of gas. Approximately 68% of our oil and NGL production during 2015 was from the Rocky Mountain region. Historically, this region has experienced wider differentials than our Permian Basin and Gulf Coast properties. If the percentage of our production from the Rocky Mountain region continues to increase, we expect that the effect of our price differentials on our revenues 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 and three way collars on approximately 62% of the oil production of our

estimated net proved developed producing reserves (as of December 31, 2015) through December 31, 2016 and 29% for 2017. 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. 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, 2015, we recognized a realized gain on oil and gas derivative contracts of \$9.5 million and an unrealized gain of \$9.8 million. The realized gain resulted in an increase in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility.

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.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development and exploratory drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. For example, the Company's proved reserves as of December 31, 2015 include proved undeveloped reserves and proved developed reserves that are behind pipe of 16,586 MBbls of oil, 4,903 MBbls of NGLs and 48,254 MMcf of gas. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. There can be no assurance that the Company will drill these locations or that the Company will be able to produce oil or gas reserves from these locations or any other potential drilling locations. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately result in the realization of proved reserves or meet the Company's expectations for

success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

A significant portion of the Company's total estimated proved reserves at December 31, 2015 were undeveloped, and those proved reserves may not ultimately be developed.

At December 31, 2015, approximately 60 percent of the Company's total estimated proved reserves on a BOE basis (19% on a PV-10 basis) were undeveloped. Recovery of undeveloped proved reserves requires significant capital expenditures and successful drilling. The Company's reserve data assumes that the Company can and will make these expenditures and conduct these operations successfully, which assumptions may not prove correct. If the Company chooses not to spend the capital to develop these proved undeveloped reserves, or if the Company is not otherwise able to successfully develop these proved undeveloped reserves, the Company will be required to write-off these proved reserves. In addition, under the SEC's rules, because proved undeveloped reserves may be booked only if they relate to wells planned to be drilled within five years of the date of booking, the Company may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. As with all oil and gas leases, the Company's leases require the Company to drill wells that are commercially productive and to maintain the production in paying quantities, and if the Company is unsuccessful in drilling such wells and maintaining such production, the Company could lose its rights under such leases. The Company's future production levels and, therefore, its future cash flow and income are highly dependent on successfully developing its proved undeveloped leasehold acreage.

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 could 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 and/or trigger certain repayment obligations. 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 flows from operations or our borrowing base decreases, 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 would 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/or to drill new wells on our remaining properties. If we cannot replace the properties sold with production from our remaining properties, our cash flows 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, 2015, our average annual estimated decline rate for our net proved developed producing reserves is 33%; 26%; 15%; 11% and 10% in 2017, 2018, 2019, 2020 and 2021, respectively, 10% in the next five years, and approximately 12% 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 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) at December 31, 2015 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Even if we are successful in our development efforts, it could take several years for a significant portion of these undeveloped reserves to generate positive cash flow.

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

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. 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 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) as of December 31, 2015 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 and completion 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. Risks that we face include landing our well bore in the desired drilling zone, staying in the desired drilling zone, running casing the entire length of the well bore and being able to run tools and recover equipment the entire length of the well bore during completion. 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 95% 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 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:

- prevailing and anticipated prices for oil and gas;
- the availability and costs of drilling and service equipment and crews;

- economic and industry conditions at the time of drilling;
- 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 and to access drilling locations;
- continuous drilling obligations; and
- lease expirations.

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 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 and the Powder River Basins, 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 pressures or 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, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, shoreline contamination, underground migration and surface spills or mishandling of chemical additives;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- leaks of gas, oil, condensate, NGL and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, 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. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure, usually down tubing or 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 and state 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 related to chemicals used in hydraulic fracturing, and the U.S. Department of the Interior, Bureau of Land Management (“BLM”) released final rules in March 2015 governing hydraulic fracturing on federal and tribal lands, including requiring chemical disclosure. BLM’s rules are currently under judicial challenge. 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 permitting guidance and an interpretive memorandum addressing the performance of such activities. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing, and planning among federal agencies and offices regarding “unconventional natural-gas production,” including hydraulic fracturing. In May 2014, the EPA announced its intent to initiate rulemaking regulations under the Toxic Substances Control Act to obtain data on chemical substances and mixtures used in hydraulic fracturing. 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. Moreover, the BLM has adopted final rules that impose more stringent technical requirements and the disclosure of chemicals used in hydraulic fracturing operations on public and Native American lands. These rules are currently under judicial challenge. 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/or 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 disclosure 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. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact water available for hydraulic fracturing. 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. In June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not lead to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA’s Science Advisory Board provided its comments on the draft study, indicating its concern that the EPA’s conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Moreover, on April 7, 2015, the

EPA proposed pre-treatment standards addressing the discharge of wastewater pollutants from hydraulic fracturing operations to publicly owned treatment works. The EPA is also conducting a study of private wastewater treatment facilities that accept oil and gas extraction wastewater. 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.

We face various risks associated with the trend toward increased anti-development activity.

As new technologies have been applied to our industry, we have seen significant growth in oil and gas supply in recent years, particularly in the US. With this expansion of oil and gas development activity, opposition toward oil and gas drilling and development activity has been growing both in the U.S. and globally. Companies in the oil and gas industry, such as us, can be the target of opposition to development from certain stakeholder groups. These anti-development efforts could be focused on:

- limiting oil and gas development;
- reducing access to federal and state owned lands;
- delaying or canceling certain projects such as offshore drilling, shale development, and pipeline construction;
- limiting or banning the use of hydraulic fracturing;
- denying air-quality permits for drilling; and
- advocating for increased regulations on shale drilling and hydraulic fracturing.

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- limited access or damage to or destruction of our property;
- legal challenges or lawsuits;
- increased regulation of our business;
- damaging publicity and reputational harm;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Our need to incur costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations. In addition, the use of social media channels can be used to cause rapid, widespread reputational harm.

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

The marketability of our production depends in part upon processing, storage 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 federal and state, regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If our access to these transportation and storage options dramatically changes, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act establishes federal oversight and regulation of over-the-counter, or OTC, derivatives and requires the Commodity Futures Trading Commission, or CFTC, and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, on November 5, 2013 the CFTC approved a proposed rule imposing position limits for certain futures and option contracts in various commodities (including gas) and for swaps that are their economic equivalents. Certain specified types of hedging transactions are exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, the CFTC has issued a proposed rule regarding the capital that a swap dealer, or major swap participant, is required to post with respect to its swap business, but has not yet issued a final rule. On January 6, 2016, the CFTC issued a final rule on margin requirements for uncleared swap transactions, which includes an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions. In addition, the CFTC has issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on our ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may require us to comply with position limits and with certain clearing and trade-execution requirements in connection with our financial derivative activities. The Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared derivative contracts with us, which could increase the cost to us of entering into such derivative contracts. When a final rule on capital requirements is issued, the Dodd-Frank Act may require our current swap counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase our costs of future financial derivative transactions. The Dodd-Frank Act may also require our current counterparties to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of commercial end-users to have access to derivative contracts to hedge or mitigate their exposure to volatility in oil, gas and NGL prices. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated derivative contracts, and reduce the availability of derivatives to protect us against commercial risks we encounter.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carry forwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2015, we had a net operating loss ("NOL") carryforward for federal income tax purposes of \$192.9 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOL we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term

tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more “5% shareholders” (as defined in the Code) at any time during a rolling three-year period. In addition, under the Code, NOL can generally be carried forward to offset future taxable income for a period of 20 years. Our ability to use our NOL during this period will be dependent on our ability to generate taxable income, and the NOL could expire before we generate sufficient taxable income.

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 significant cyber attacks, we may suffer such losses in the future. We did have a cyber attack in 2010 relating to electronic bank transfers, although the monetary loss was very minimal, additional procedures were implemented to safeguard against future cyber attacks. 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.

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. 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 in accordance with SEC requirements 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, 2015 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, 2015. The average realized sales prices as of such date used for purposes of such estimates were \$2.36 per Mcf of gas and \$41.25 per Bbl of oil. The December 31, 2015 estimates also assume that we will make future capital expenditures of approximately \$338.3 million in the aggregate primarily from 2016 through 2021, which are necessary to develop and realize the value of proved reserves on our properties. We cannot assure you that we will have sufficient capital in the future to make these capital expenditures. In addition, approximately 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) as of December 31, 2015 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, 2015 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2015 and costs in effect on December 31, 2015, 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 and salt water 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 and local 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, the disposal of wastes 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 at times restricted the rates of flow from oil and gas wells below actual production capacity. U.S. federal, state and local 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 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 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 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 December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020. It is possible that the Paris Agreement and subsequent domestic and international regulations will have adverse effects on the market for oil, gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, oil, gas and other fossil fuel products. In the United States, at the state level, several 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 legislative level, various climate change legislative measures have been considered by the U.S. Congress, but 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 are unlikely to become law in the near future due to opposition in the U.S. House of Representatives. We are unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect our operations, financial condition and results of operations.

As a result of the U.S. 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 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 gas exploration and production industry and the pipeline industry. Further, on September 18, 2015, the EPA proposed three rules and issued a notice of availability of a draft Control Techniques Document relating to air emissions (including GHG emissions) from the oil and gas industry. These rules are expected to be finalized in 2016. 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.

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.

EPA's new ground-level ozone standards may result in more stringent regulation of air emissions from, and adverse economic impacts on, our operations.

In October 2015, the U.S. Environmental Protection Agency (EPA) issued a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards designed to provide protection of public health and welfare, respectively. The final rule became effective in December 2015. Certain areas of the country in compliance with the ground-level ozone NAAQS standard may be reclassified as non-attainment and such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement more stringent regulations necessary to come into compliance with the new NAAQS, which could apply to our operations. Compliance with these final rules could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

Proposed legislation and regulation under consideration regarding rail transportation could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

We presently sell all of our oil production at the lease, either by truck or pipeline, where custody transfers to the purchaser, accordingly it is unknown to us how much of the oil production is ultimately shipped by rail. In response to recent train derailments occurring in the United States, U.S. regulators are implementing or considering new rules to address the safety risks of transporting oil by rail. On January 23, 2014, the NTSB issued a series of recommendations to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) developing an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) auditing shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the DOT issued an emergency order requiring all persons, prior to offering oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of oil be handled as a Packing Group I or II hazardous material. The introduction of these or other regulations that result in new requirements addressing the type, design, specifications or construction of rail cars used to transport oil could result in severe transportation capacity constraints during the period in which new rail cars are retrofitted or constructed to meet new specifications.

We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or rail transportation of oil could increase our costs of doing business and limit our ability to transport and sell our oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

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, 2015, we had 106,346,001 shares of common stock outstanding of which 9,639,046 shares were held by affiliates and, in addition, 6,807,729 shares of common stock were subject to outstanding options granted under stock option plans (of which 4,305,228 shares were vested at December 31, 2015).

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

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

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

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the oil and gas industry;
- sales of common stock or other actions by our stockholders;
- additions or departures of key management personnel;
- commencement of or involvement in litigation;
- speculation in the press or investment community regarding our business;
- an inability to maintain the listing of our common stock on a national securities exchange;
- market conditions; and
- analysts' estimates and other events in the oil and gas industry.

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

Subject to the rules of The NASDAQ Stock Market, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock.

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 and bylaws 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.

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, 2015.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage ⁽¹⁾		Total Net Acres ⁽²⁾
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	
Rocky Mountain	36,855	22,108	32,957	21,590	2,758	316	44,014
Permian Basin	17,766	14,967	10,226	8,130	12,008	5,273	28,370
Onshore Gulf Coast	8,166	7,654	5,827	5,608	2,975	879	14,141
Total	62,787	44,729	49,010	35,328	17,741	6,468	86,525

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

(2) Includes 1,217 net acres in the Permian Basin region that are included in both developed and fee mineral acres.

The flowing table sets forth Abraxas' net undeveloped acreage subject to expire by year:

	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>
Rocky Mountain	280	—	647	—
Permian Basin	822	79	—	—
Onshore Gulf Coast	672	3,078	149	—

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2015:

	Productive Wells			
	Oil		Gas	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Rocky Mountain	376.0	81.7	412.0	11.2
Permian Basin	189.0	126.5	51.0	27.6
Onshore Gulf Coast	50.5	39.1	27.5	25.4
Total	<u>615.5</u>	<u>247.3</u>	<u>490.5</u>	<u>64.2</u>

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, 2015, 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 DeGolyer 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, 2015 included a total of 335 properties and our internal report included 343 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 4, 2016, 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, 2015 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 37 years of experience in reserve evaluations. The operations department of Abraxas assisted in the process. 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, 2015, commodity prices over the prior 12-month period and year end costs were used in estimating future net cash flows.

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2015. All of our reserves are located in the United States.

**Summary of Oil, NGL and Gas Reserves
As of December 31, 2015**

<u>Reserve Category</u>	<u>Oil (MBbls)</u>	<u>NGL (MBbls)</u>	<u>Gas (MMcf)</u>	<u>Oil Equivalents (MBoe)</u>
Proved				
Developed	10,022	1,957	31,298	17,194
Undeveloped	14,109	4,599	43,729	25,996
Total Proved	<u>24,131</u>	<u>6,556</u>	<u>75,027</u>	<u>43,190</u>

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2013, 2014, and 2015, 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, 2015. 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, 2015 report. The average realized sales prices used for purposes of such estimates were \$41.25 per Bbl of oil and \$2.36 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately \$338.3 million in the aggregate primarily in the years 2016 through 2021, 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 are 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, 2015, the Company’s net capitalized

costs of oil and gas properties exceeded the present value of our estimated proved reserves, resulting in a proved property impairment of \$128.6 million. If commodity prices remain at depressed levels or decrease further, we could be required to further write down the carrying value of our reserves during 2016 which would also reduce our net income.

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 2015 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. There are no PUDs as of December 31, 2015, included in this report that are not planned to be developed within five years.

	<u>MMBoe</u>
PUDs at December 31, 2014	24,459
Revisions of prior estimates	(8,582)
Extensions, discoveries, and other additions	15,333
Conversion to developed	(5,214)
Sales	—
PUDs at December 31, 2015	<u>25,996</u>

We spent approximately \$57.9 million converting 15 proved undeveloped reserves cases to proved developed reserves in 2015. These 15 wells represent 2.6 MMBOE of reserves. The Company also added approximately 600 MBOE in net proved undeveloped reserves as the result of upward revisions in the Bakken PUD projections based on existing well performance.

We also added 28 new proved undeveloped Bakken locations on the Company’s prospect acreage in McKenzie County, North Dakota, accounting for approximately 6.5 MMBOE of net reserves, 20 of which are in the Three Forks (second bench) locations which were proved during 2015 by local development results. There were also 8 downspaced locations added on the Yellowstone Unit by virtue of the fact that operatorship of that unit passed to Abraxas during 2015 thereby allowing the implementation of the Company’s standard Bakken spacing plan.

We also gained proved undeveloped reserves of approximately 1.4 MMBOE net, due to the change in classification of 21 probable and possible undeveloped Bakken cases into the proved category. These locations achieved proved status by virtue of offsetting development activity during 2015. An equivalent volume of reserves was removed from the probable and possible undeveloped category as a result of this change in classification.

We also added 6 new Montoya proved undeveloped locations on the Company’s prospect acreage in Ward County, Texas. These locations were added based on the performance of existing Montoya producers on the subject leasehold. Net reserves of approximately 6.5 MMBOE are attributable to these new locations.

We dropped 38 South Texas Eagle Ford proved undeveloped cases from our reserve report due to lack of economic viability at the lower commodity prices. These cases represented approximately 7.8 MMBOE of net reserves.

For the period ending December 31, 2015, proved producing reserves decreased by approximately 6.6 MMBOE, net, due primarily to shortened economic lives resulting from lower product price forecasts.

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, 2014 and 2015:

	December 31,	
	2014	2015
	(In thousands)	
PV-10	\$ 637,443	\$197,251
Present value of future income taxes discounted at 10%	(124,886)	—
Standardized measure of discounted future net cash flows	<u>\$ 512,557</u>	<u>\$197,251</u>

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 NGLs and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three years ended December 31 by our major operating regions:

	2013	2014	2015
Oil production (Bbls)			
Rocky Mountain	501,657	816,323	1,000,425
Permian Basin	100,846	86,614	76,391
Onshore Gulf Coast	224,625	491,142	363,404
Mid-Continent ⁽¹⁾	2,197	—	—
Total	<u>829,325</u>	<u>1,394,079</u>	<u>1,440,220</u>
Gas production (Mcf)			
Rocky Mountain	940,969	1,057,759	1,146,953
Permian Basin	1,288,198	1,003,018	973,840
Onshore Gulf Coast	1,029,346	856,928	894,039
Mid-Continent ⁽¹⁾	84,384	—	—
Total	<u>3,342,897</u>	<u>2,917,705</u>	<u>3,014,832</u>
NGL production (Bbls)			
Rocky Mountain	50,421	95,384	132,846
Permian Basin	88,254	79,321	54,877
Onshore Gulf Coast	7,871	32,592	50,392
Mid-Continent ⁽¹⁾	178	—	—
Total	<u>146,724</u>	<u>207,297</u>	<u>238,115</u>
Total production (MBoe)⁽²⁾	<u>1,533</u>	<u>2,088</u>	<u>2,181</u>
Average sales price per Bbl of oil⁽³⁾			
Rocky Mountain	\$ 87.80	\$ 78.59	\$ 39.23
Permian Basin	\$ 91.72	\$ 84.38	\$ 44.69
Onshore Gulf Coast	\$ 101.59	\$ 88.44	\$ 45.71
Mid-Continent ⁽⁴⁾	\$ 90.53	\$ —	\$ —
Composite	\$ 92.02	\$ 82.42	\$ 41.15
Average sales price per Mcf of gas⁽³⁾			
Rocky Mountain	\$ 3.33	\$ 4.41	\$ 1.46
Permian Basin	\$ 3.47	\$ 4.29	\$ 2.24
Onshore Gulf Coast	\$ 2.99	\$ 3.73	\$ 2.24
Mid-Continent ⁽¹⁾	\$ 2.87	\$ —	\$ —
Composite	\$ 3.27	\$ 4.17	\$ 1.94

	2013	2014	2015
Average sales price per Bbl of NGL			
Rocky Mountain	\$40.59	\$36.41	\$ 5.49
Permian Basin	\$32.12	\$31.10	\$13.03
Onshore Gulf Coast	\$18.96	\$21.41	\$ 8.60
Mid-Continent ⁽¹⁾	\$30.09	\$ —	\$ —
Composite	\$34.32	\$32.02	\$ 7.89
Average sales price per Boe⁽³⁾	\$60.18	\$64.04	\$30.72
Average cost of production per Boe produced⁽⁴⁾			
Rocky Mountain	\$13.11	\$ 7.36	\$ 6.43
Permian Basin	\$14.50	\$15.15	\$15.76
Onshore Gulf Coast	\$ 8.34	\$ 9.30	\$12.71
Mid-Continent ⁽¹⁾	\$15.65	\$ —	\$ —
Composite	\$12.71	\$ 9.22	\$ 9.31

(1) All of our Mid-Continent properties were sold in 2013.

(2) 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.

(3) Before the impact of hedging activities.

(4) Production costs include controllable direct lease operating costs but exclude ad valorem taxes, production taxes and non-recurring lease operating costs.

Within the above major operating regions, the Rocky Mountain and Onshore Gulf Coast regions represented more than 15% of our proved reserves as of December 31, 2015. The following is a summary, by product sold, for each primary field in these regions for the three years ended December 31, 2015:

	2013	2014	2015
Rocky Mountain Region			
Oil production (Bbls)			
Bakken/Three Forks	296,451	660,447	862,458
Gas production (Mcf)			
Bakken/Three Forks	351,248	570,792	687,200
NGL production (Bbls)			
Bakken/Three Forks	31,229	77,120	116,392
Average sales price per Bbl of oil⁽¹⁾			
Bakken/Three Forks	\$ 88.35	\$ 78.01	\$ 39.15
Average sales price per Mcf of gas⁽¹⁾			
Bakken/Three Forks	\$ 2.87	\$ 4.60	\$ 1.07
Average sales price per Bbl of NGL⁽¹⁾			
Bakken/Three Forks	\$ 37.34	\$ 34.86	\$ 3.78
Average cost of production per Boe produced⁽²⁾			
Bakken/Three Forks	\$ 10.03	\$ 6.88	\$ 4.05
Onshore Gulf Coast Region			
Oil production (Bbls)			
Eagle Ford	154,910	431,892	305,797
Gas production (Mcf)			
Eagle Ford	45,560	229,385	325,942
NGL production (Bbls)			
Eagle Ford	7,530	32,592	50,392
Average sales price per Bbl of oil⁽¹⁾			
Eagle Ford	\$ 102.17	\$ 88.30	\$ 45.87
Average sales price per Mcf of gas⁽¹⁾			
Eagle Ford	\$ 3.11	\$ 3.69	\$ 2.44
Average sales price per Bbl of NGL			
Eagle Ford	\$ 18.48	\$ 21.42	\$ 8.60
Average cost of production per Boe produced⁽²⁾			
Eagle Ford	\$ 6.40	\$ 7.98	\$ 12.33

(1) Before the impact of hedging activities.

(2) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

Drilling Activities

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

	2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Rocky Mountain	—	—	—	—	—	—
Permian Basin	—	—	—	—	—	—
Onshore Gulf Coast	—	—	—	—	—	—
Total	—	—	—	—	—	—
Dry wells						
Permian Basin	2.0	2.0	—	—	—	—
Total	2.0	2.0	—	—	—	—
Development						
Productive						
Rocky Mountain	31.0	3.1	10.0	6.4	21.0	6.8
Permian Basin	1.0	1.0	—	—	—	—
Onshore Gulf Coast	11.0	3.9	10.0	10.0	4.0	4.0
Total	43.0	8.0	20.0	16.4	25.0	10.8

In addition to the above drilling activity, as of December 31, 2015 we had 6.0 gross (4.7 net) operated wells and 1.0 gross (0.37 net) non-operated well that were drilled and uncompleted, that are not represented in the above table.

Present Activities

As of March 10, 2016, we had six gross (4.7 net) operated wells and 1.0 gross (0.37 net) non-operated well that are drilled and waiting for completion later in 2016.

In the following discussion, production rates do not include the impact of NGL production and shrinkage from processing including the flaring of gas. The following provides an overview of our present activities:

Williston Basin

At Abraxas' North Fork prospect, in McKenzie County, North Dakota, the Sten-Rav 1H and Ravin 8H producing from the Three Forks, averaged 900 boepd (678 barrels of oil per day, 1,332 mcf of natural gas per day) over the wells' peak 30 days of production. The Stenehjem 5H producing from the Middle Bakken, averaged 809 boepd (604 barrels of oil per day, 1,232 mcf of natural gas per day) over the well's peak 30 days of production. Each well was constrained on a smaller than normal choke to minimize flaring. Abraxas owns a working interest of approximately 76% in the Ravin Northwest wells.

On the Stenehjem Super Pad, Abraxas successfully drilled and cased the Stenehjem 10H-15H. These six wells are scheduled for completion in the third quarter of 2016. Abraxas owns a working interest of approximately 78% in the Stenehjem 10H-15H. Offsetting these six wells, Abraxas recently agreed to participate in a unit line well drilled by another operator where Abraxas holds a 36% working interest. All seven wells are now drilled and are waiting on completion. Abraxas has idled Raven Rig #1 until commodity prices improve.

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 4.25%, and is payable in monthly installments of principal and interest of \$34,354. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The note matures in July 2023. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2015, \$4.1

million was outstanding on the note. We lease office space in Dickinson, North Dakota for a monthly rental of \$2,320 through October 2016. The lease expires on October 31, 2016. We lease office space in Lusk, Wyoming for a monthly rental of \$750. The lease expires on December 31, 2016. We also lease office space in Denver, Colorado for a monthly rental of \$959. The lease expires on December 31, 2016.

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, 582 acres of land in McKenzie County, North Dakota and 12,178 acres of land in Pecos County, Texas.

We own 32 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 three houses in 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, 2015, 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.

<u>Period</u>	<u>High</u>	<u>Low</u>
2014		
First Quarter	\$4.15	\$2.99
Second Quarter	6.41	3.82
Third Quarter	6.45	4.81
Fourth Quarter	5.30	2.33
2015		
First Quarter	\$3.56	\$2.60
Second Quarter	3.98	2.82
Third Quarter	2.95	1.20
Fourth Quarter	1.95	0.84
2016 First Quarter (Through March 10, 2016)	\$1.31	\$0.65

Holders

As of March 10, 2016, we had 106,346,001 shares of common stock outstanding and approximately 1,041 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.

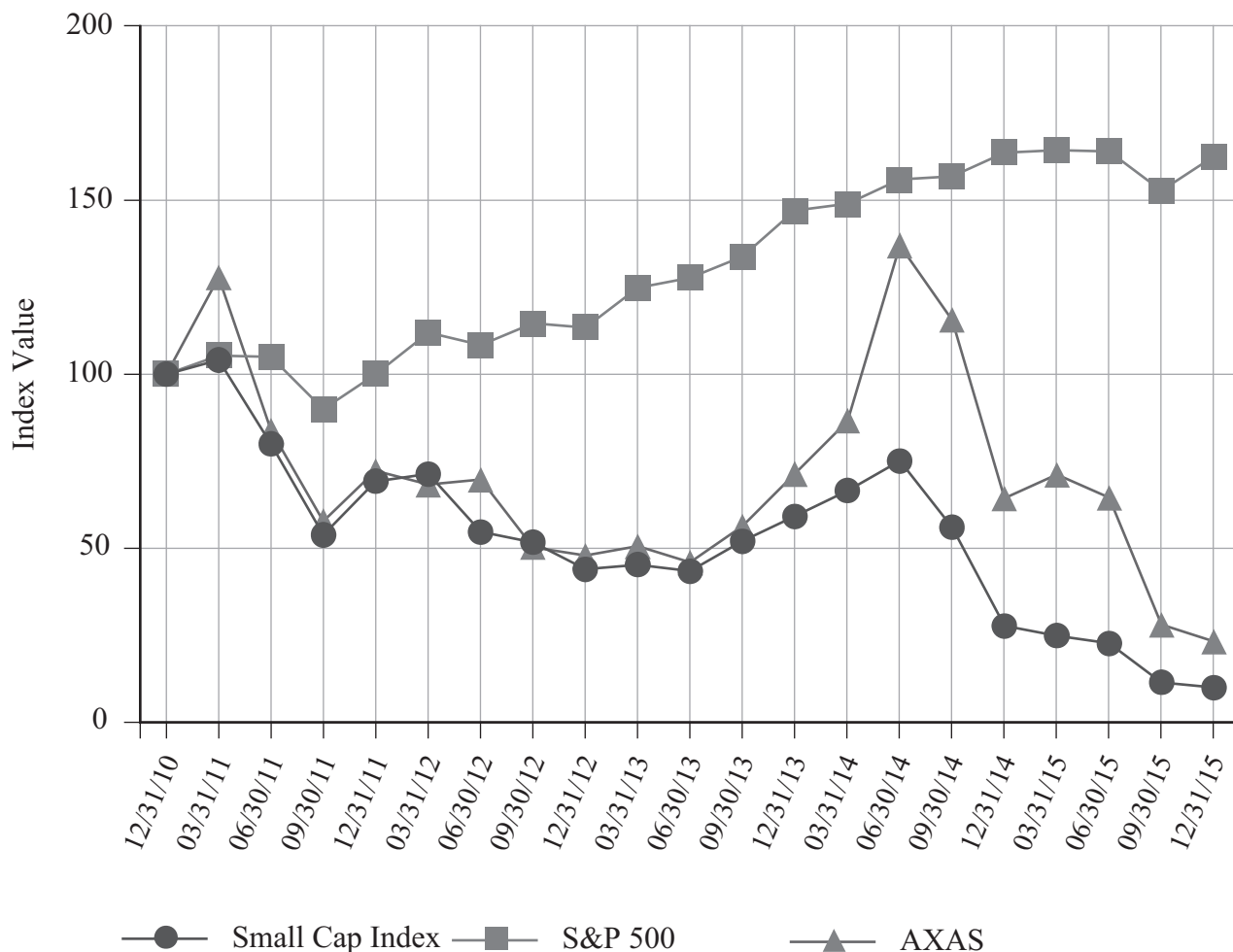
Performance Graph

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 index of comparable companies based on 1) companies of similar size, 2) other similar companies in the oil and gas exploration industry, and 3) similar operations in comparable geographies compiled in 2015 by Longnecker & Associates ("L&A"). L&A then analyzed each company based on:

- Market capitalization;
- Revenue;
- Assets;
- Enterprise value; and
- Operational similarities.

Using these criteria, the following list of comparable companies: Approach Resources, Inc. (AREX), Callon Petroleum Company (CPE), Clayton Williams Energy, Inc. (CWEI), Comstock Resources, Inc. (CRK), Contango Oil & Gas Company (MCF), Emerald Oil (EOX), Evolution Petroleum Corp. (EPM), Gastar Exploration Inc. (GST), Magnum Hunter Resources Corp. (MHR), Northern Oil and Gas, Inc (NOG), Penn Virginia Corporation (PVA), Swift Energy Co. (SFY), Triangle Petroleum Corporation (TPLM) and Warren Resources Inc. (WRES).

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, 2010, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2011, 2012, 2013, 2014 and 2015.



	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
Small Cap Index	\$100.00	\$ 69.26	\$ 43.97	\$ 59.15	\$ 27.68	\$ 9.96
S&P 500	\$100.00	\$100.00	\$113.40	\$146.97	\$163.71	\$162.52
AXAS	\$100.00	\$ 72.21	\$ 47.92	\$ 71.36	\$ 64.33	\$ 23.19

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, 2011 through 2015. 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,				
	2011	2012	2013	2014	2015
	(In thousands, except per share data)				
Total revenue—continuing operations	\$ 63,105	\$ 65,664	\$ 92,324	\$133,776	\$ 67,030
Net income (loss)	\$ 13,743	\$ (18,791)	\$ 38,647	\$ 63,269	\$ (127,110)
Net income (loss) from continuing operations	\$ 14,395	\$ 3,106	\$ 46,841 ⁽²⁾	\$ 61,951	\$ (127,090) ⁽⁵⁾
Net (loss) income from discontinued operations	\$ (652)	\$ (21,897) ⁽¹⁾	\$ (8,194) ⁽³⁾	\$ 1,318 ⁽⁴⁾	\$ (20)
Net income (loss) per common share—diluted—continuing operations	\$ 0.15	\$ 0.04	\$ 0.50	\$ 0.61	\$ (1.21)
Weighted average shares outstanding—diluted	92,244	91,914	93,538	101,468	104,605
Total assets	\$241,150	\$240,607	\$223,650	\$374,899	\$ 267,872
Long-term debt, excluding current maturities	\$126,258	\$124,101	\$ 41,790	\$ 76,554	\$ 138,402
Total stockholders’ equity	\$ 62,651	\$ 46,700	\$ 86,906	\$207,495	\$ 84,465

(1) Includes proved property impairment of \$19.8 million related to discontinued operations.

(2) Includes a gain on the sale of properties of \$33.4 million.

(3) Includes proved property impairment of \$6.0 million related to discontinued operations.

(4) Includes a gain of \$1.9 million on the sale of our Canadian subsidiary.

(5) Includes proved property impairment of \$128.6 million.

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

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion excludes the results of our Canadian subsidiary which was sold on October 31, 2014. The results of these foreign operations are included as discontinued operations in the accompanying Consolidated Financial Statements and Notes thereto.

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. 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 acreage acquisitions in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

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

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

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

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL, and gas prices in the future. The market price of oil and condensate, NGL and gas in 2016 will impact the amount of cash generated from operating activities, which will in turn impact our financial position. As of March 10, 2016, the NYMEX oil and gas price was \$37.84 per Bbl of oil and \$1.79 per Mcf of gas, respectively, representing declines of 22% and 31%, respectively, from the average NYMEX prices in 2015.

During 2015, the NYMEX future price for oil averaged \$48.76 per barrel as compared to \$92.91 per barrel in 2014. During 2015 the NYMEX future spot price for gas averaged \$2.63 per MMBtu compared to \$4.26 per MMBtu in 2014. Prices closed on December 31, 2015 at \$37.04 per Bbl of oil and \$2.34 per MMBtu of gas. If commodity prices remain at these levels or continue to 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 oil and gas prices remain depressed or continue to decline, our revenues, profitability and cash flow from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income. Finally, low commodity prices will likely cause a reduction of the borrowing base under our credit facility. The borrowing base under our credit facility is next scheduled to be redetermined on April 1, 2016.

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;
- quality of the hydrocarbons; and
- gathering, processing and transportation costs.

The following table sets forth our average differentials for the years ended December 31, 2013, 2014 and 2015:

	Oil			Gas		
	2013	2014	2015	2013	2014	2015
Average realized price ⁽¹⁾	\$92.02	\$ 82.42	\$41.15	\$ 3.27	\$ 4.17	\$ 1.94
Average NYMEX price	\$98.06	\$ 92.91	\$48.76	\$ 3.73	\$ 4.26	\$ 2.63
Differential	<u>\$ (6.04)</u>	<u>\$ (10.49)</u>	<u>\$ (7.61)</u>	<u>\$ (0.46)</u>	<u>\$ (0.09)</u>	<u>\$ (0.69)</u>

(1) Average realized prices are before the impact of hedging activities.

The Company's derivative contracts consist of NYMEX-based fixed price swaps and three-way collar contracts. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Three-way collar contracts combine a long put, a short put and a short call. Under a collar, we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put). The use of the long put combined with a short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limits our exposure to future settlement payments while also restricting our downward risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle our contracts for the market price plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.

Our hedging arrangements equate to approximately 62% of the estimated oil production from our net proved developed producing reserves (as of December 31, 2015) through December 31, 2016, and 29% in 2017. By removing a 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 2013, we incurred a net loss of \$2.5 million, consisting of a loss of \$5.0 million related to closed contracts and a gain of \$2.5 million related to open contracts. In 2014, we incurred a gain of \$25.2 million, consisting of a gain of \$0.3 million on closed contracts and a gain of \$24.9 million related to open contracts. In 2015 we incurred a gain of \$19.3 million, consisting of a gain of \$9.5 million on closed contracts and a gain of \$9.8 million related to open contracts. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at December 31, 2015:

Fixed Price Swaps:

<u>Contract Periods</u>	<u>Oil—WTI</u>	
	<u>Daily Volume (Bbl)</u>	<u>Swap Price (per Bbl)</u>
2016	948	\$84.10
2017	608	\$78.55

Collar contracts combined with short puts (three way collars):

	<u>Daily Volume (Bbl)</u>	<u>Floor (Long Put)</u>	<u>Ceiling (Short Call)</u>	<u>Short Put</u>
2016	1,000	\$60.00	\$71.00	\$45.00

At December 31, 2015, the aggregate fair market value of our commodity derivative contracts was an asset of approximately \$27.4 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, 2015, our average annual estimated decline rate for our net proved developed producing reserves is 33%; 26%; 15%; 11% and 10% in 2017, 2018, 2019, 2020 and 2021, respectively, 10% in the next five years, and approximately 12% 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 2015 of \$69.4 million related to our exploration and development activities. We have a capital expenditure budget for 2016 of approximately \$40.0 million. This budget assumes an improvement in commodity prices by the summer of 2016, and re-starting the Raven Rig #1. However, if commodity prices stay at current levels or decline further and we elect to keep the Raven Rig #1 idled, our capital expenditures could be approximately \$17.5 million which we intend to fund primarily with cash flows from operations. Substantially all of the \$17.5 million would be spent on completing previously drilled wells in the Bakken/Three Forks in the Rocky Mountain region, which were classified as PDNP as of December 31, 2015. The 2016 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 including under our credit facility, 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, 2013, 2014 and 2015:

	Year Ended December 31,		
	2013	2014	2015
Total production (MBoe)	1,533	2,088	2,181
Average daily production (Boepd)	4,201	5,720	5,975
% Oil/ NGL	64%	77%	77%

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, 2015, we had approximately \$31.0 million of availability under our credit facility and \$3.5 million in cash. The availability under our credit facility is subject to a borrowing base determined by our lenders. This borrowing base is subject to semi-annual redeterminations. The next redetermination becomes effective on April 1, 2016.

Borrowings and Interest. At December 31, 2015, we had a total of \$134.0 million outstanding under our credit facility and total indebtedness of \$140.7 million (including the current portion). 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.

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, 2015, we operated properties accounting for approximately 95% 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, 2015, we drilled or participated in 145 gross (55.8 net) wells of which 97% 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 60% of our estimated proved reserves on a BOE basis (19% on a PV-10 basis) at December 31, 2015 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.

2016 Outlook

Market prices for oil, gas and NGL are inherently volatile. Accordingly, we cannot predict with certainty the future prices for the commodities we produce and sell. Current market fundamentals indicate prices for oil, gas and NGL will continue to be depressed for much of 2016. Although changes in OPEC production strategies, geopolitical risks or other factors could impact current forecasts, we anticipate weak commodity prices throughout 2016. Depressed prices for oil and gas will likely have a material adverse effect on our results of operations and liquidity. Our primary sources of liquidity are cash flow from operations and borrowings under our credit facility. Cash flow from operations is sensitive to many variables, the most volatile of which is the price of the oil, gas and NGL we produce and sell. Our consolidated cash flow from operations decreased in 2015 as a result of the significant decrease in commodity prices. Availability under our credit facility is currently subject to a borrowing base of \$165.0 million. The borrowing base is subject to scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations. 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. The lenders under our credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Given the ongoing decline in commodity prices for oil, gas and NGL, it is likely that reductions in our borrowing base could arise in 2016.

In 2015, as a result of the sharp decline in commodity prices, we incurred an impairment to our proved properties of \$128.6 million. We expect to record additional impairments of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month unweighted average oil and gas prices through March 1, 2016 of \$46.04 per Bbl of oil and \$2.48 per Mcf of gas being held constant for the trailing 12-month period we estimate that we will record a ceiling test write down on our existing assets of approximately \$30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of \$72.7 million for the remainder of the year ending December 31, 2016. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGL for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While we will continue to operate and develop our portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs to be within our cash flow from operations. As a result, we are significantly reducing our capital budget in response to lower commodity prices. We are also committed to reducing our G&A and field-level operating costs commensurate with our reduced, but focused, activity level. Effective February 1, 2016, the named executive officers of Abraxas took a voluntary salary reduction of 20% and other employees, depending on salary thresholds, took voluntary cuts of 10%—20%. It is anticipated that these reductions will reduce G&A cost by approximately \$0.8 million during 2016.

Results of Operations

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

	Year Ended December 31,		
	(In thousands, except per unit data) 2013	2014	2015
Operating revenue ⁽¹⁾ :			
Oil sales	\$76,311	\$114,898	\$ 59,270
Gas sales	10,921	12,166	5,854
NGL sales	5,036	6,637	1,878
Total operating revenues	<u>\$92,268</u>	<u>\$133,701</u>	<u>\$ 67,002</u>
Operating income (loss)	\$23,097	\$ 39,922	\$(141,805)
Oil sales (MBbls)	829	1,394	1,440
Gas sales (MMcf)	3,343	2,918	3,015
NGL sales (MBbls)	147	207	238
Oil equivalents (MBoe)	1,533	2,088	2,181
Average oil sales price (per Bbl) ⁽¹⁾	\$ 92.02	\$ 82.42	\$ 41.15
Average gas sales price (per Mcf) ⁽¹⁾	\$ 3.27	\$ 4.17	\$ 1.94
Average NGL sales price (per Bbl)	\$ 34.32	\$ 32.02	\$ 7.89
Average oil equivalent sales price (Boe)	\$ 60.18	\$ 64.04	\$ 30.72

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

Comparison of Year Ended December 31, 2015 to Year Ended December 31, 2014

Operating Revenue. During the year ended December 31, 2015, operating revenue decreased to \$67.0 million from \$133.7 million in 2014. The decrease in revenue was primarily due to a significant decline in commodity prices in 2015. Lower commodity prices had a negative impact on revenue of \$69.0 million in 2015. During 2015 we experienced a decline in the average realized oil price of approximately 50% from 2014 levels. Average realized gas prices declined by approximately 53% and average realized NGL prices declined approximately 75% from 2014 levels. Higher sales volumes of all products added \$2.3 million to revenue in 2015 as compared to 2014.

Oil sales volumes increased to 1,440 MBbls for the year ended December 31, 2015 from 1,394 MBbls for the same period of 2014. The increase in oil sales volumes was due to new production brought on line in 2015. New wells brought onto production in 2015 contributed 298 MBbls to production for the year ended December 31, 2015, offset by natural field declines and property sales. Gas sales volumes increased to 3,015 MMcf for the year ended December 31, 2015 from 2,918 MMcf for the year ended December 31, 2014. The increase in gas production was due to new wells being brought on line,

offset by natural field declines. New wells brought onto production during 2015 contributed 299 MMcf to production for the year ended December 31, 2015. NGL sales increased to 238 MBbls for the year ended December 31, 2015 from 207 MBbls for the same period of 2014. The increase in NGL sales was primarily due to increased gas production from fields in West Texas, Wyoming and North Dakota that have a higher NGL content than our historical gas production.

Lease Operating Expenses (“LOE”). LOE for the year ended December 31, 2015 decreased to \$23.1 million from \$25.9 million in 2014. The decrease in LOE was primarily due to lower cost of services, and less non-recurring LOE in 2015 compared to 2014. Additionally, due to the significant decline in commodity prices, marginal wells have been temporarily shut in to control costs. LOE per Boe for the year ended December 31, 2015 was \$10.58 compared to \$12.39 for the same period of 2014. The decrease in LOE per Boe was attributable to higher sales volumes in 2015 as well as lower costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2015 decreased to \$6.7 million from \$11.5 million in 2014. The decrease was primarily due to significantly lower realized prices in 2015 as compared to 2014 which was partially offset by increased production in 2015 as compared to 2014. Production and ad valorem taxes as a percentage of oil and gas revenue increased to 10% in 2015 from 9% in 2014. The increase is due primarily to a higher production in the Rocky Mountain region that has a higher tax rate.

General and Administrative (“G&A”) Expense. G&A expense, excluding stock-based compensation, decreased to \$7.9 million for the year ended December 31, 2015 from \$10.7 million in 2014. G&A expense per Boe was \$3.61 for the year ended December 31, 2015 compared to \$5.11 for the same period of 2014. The decrease in G&A was primarily due to performance bonuses in 2014 that did not occur in 2015. Additionally, as a result of the current price environment, emphasis has been placed on reducing cost.

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, 2015 increased to \$3.9 million from \$2.7 million in 2014. The increase was due to the grant of a greater number of options in 2015 as compared to 2014.

Depreciation, Depletion, and Amortization (“DD&A”) Expenses. DD&A expense decreased to \$38.7 million for the year ended December 31, 2015 from \$43.1 million in 2014. DD&A decreased primarily due to decreased future development costs included in the 2015 reserve reports. DD&A per Boe for 2015 was \$17.76 compared to \$20.66 in 2014. The decrease in DD&A per BOE was due to lower future development cost in 2015 as compared to 2014.

Interest Expense. Interest expense increased to \$3.9 million in 2015 from \$2.6 million for 2014. The increase was primarily due to higher levels of debt during 2015 as compared to 2014.

Income Taxes. An income tax benefit was recognized in 2015 as the result of an overpayment of state income taxes in 2014 that was refunded in 2015, as well as a benefit of a capital loss carryback which resulted in a refund of prior year federal taxes of \$242,000

Loss (Gain) on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and 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 Accounting Standards Codification 815, Derivatives and Hedging “ASC 815”; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of fixed price swaps and three way collar contracts in 2015 and fixed price swaps in 2014. The net estimated value of our commodity derivative contracts was an asset of approximately \$27.4 million as of December 31, 2015. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year ended December 31, 2015, we recognized a gain on our derivative contracts of approximately \$19.3 million, consisting of a gain of \$9.5 million on closed contracts and a gain of \$9.8 million on the mark to market valuation of open contracts. For the year-ended December 31, 2014, we incurred a gain of \$25.2 million, consisting of a gain of \$0.3 million on closed contracts and a gain of \$24.9 million related to open contracts.

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, 2014 the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2015, the net capitalized cost of our oil and gas properties exceeded the present value of our estimated proved reserves, resulting in the recognition of an impairment of \$128.6 million in 2015. 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 2015 which were \$50.12 per Bbl for oil and \$2.63 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

We expect to record an additional impairment of our oil and gas properties during 2016 as a result of declining oil and gas prices. Based on the 12-month unweighted average oil and gas prices through March 1, 2016 of \$46.04 per Bbl of oil and \$ 2.48 per Mcf of gas being held constant for the trailing 12-month period we estimate that we will record a ceiling test write down on our existing assets of approximately \$30.1 million at March 31, 2016 and if such prices do not change during the remainder of 2016 an additional write down of \$72.7 million for the remainder of the year ending December 31, 2016.

However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, gas and NGLs for the remainder of 2016, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

Comparison of Year Ended December 31, 2014 to Year Ended December 31, 2013

Operating Revenue. During the year ended December 31, 2014, operating revenue increased to \$133.7 million from \$92.3 million in 2013. The increase in revenue was primarily due to a 68% increase in oil sales volumes in 2014 as compared to 2013, offset by lower realized prices for oil and NGL prices. Gas sales volumes were down by approximately 13%; however the decrease in gas volumes was offset by higher realized gas prices. We also had a significant increase in NGL sales volumes in 2014 as compared to 2013, which was partially offset by lower realized NGL prices. Increased sales volumes of oil and NGL contributed \$54.0 million to operating revenue. Lower gas sales volumes had a negative impact on operating revenue of \$1.4 million. Higher realized prices for gas contributed \$2.6 million to operating revenue, while lower oil and NGL prices had a negative impact on revenue of \$13.9 million in 2014.

Oil sales volumes increased to 1,394 MBbls for the year ended December 31, 2014 from 829 MBbls for the same period of 2013. The increase in oil sales volumes was due to new production brought on line in 2014. New wells brought onto production in 2014 contributed 722 MBbls to production for the year ended December 31, 2014, offset by natural field declines and property sales. Gas sales volumes decreased to 2,918 MMcf for the year ended December 31, 2014 from 3,343 MMcf for the year ended December 31, 2013. The decrease in gas production was due to natural field declines; the timing of new wells being brought on line, property sales, as well as our emphasis on drilling oil wells as opposed to gas wells. New wells brought onto production during 2014 contributed 594 MMcf to production for the year ended December 31, 2014. Due to continued weakness in gas prices, our focus during 2014 was primarily on oil and NGL projects. NGL sales increased to 207 MBbls for the year ended December 31, 2014 from 147 MBbls for the same period of 2013. The increase in NGL sales was primarily due to increased gas production from fields in West Texas, Wyoming and North Dakota that have a higher NGL content than our historical gas production.

Lease Operating Expenses. LOE for the year ended December 31, 2014 increased to \$25.9 million from \$23.2 million in 2013. The increase in LOE was primarily due to increased cost of services, and significant non-recurring LOE. The increase was partially offset by sales of producing properties in 2013, which had higher operating costs. LOE per Boe for the year ended December 31, 2014 was \$12.39 compared to \$15.13 for the same period of 2013. The decrease in LOE per Boe was attributable to higher sales volumes in 2014, partially offset by higher costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2014 increased to \$11.5 million from \$8.4 million in 2013. The increase was primarily due to increased production in 2014 as compared to 2013. Production and ad valorem taxes as a percentage of oil and gas revenue remained constant at approximately 9% for the years ended December 31, 2014 and 2013.

General and Administrative Expense. G&A expense, excluding stock-based compensation, increased to \$10.7 million for the year ended December 31, 2014 from \$9.9 million in 2013. G&A expense per Boe was \$5.11 for the year ended December 31, 2014 compared to \$6.45 for the same period of 2013. The increase in G&A was primarily due to additional personnel and salary increases.

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, 2014 increased to \$2.7 million from \$2.1 million in 2013. The increase was due to the grant of a greater amount of shares of restricted stock in 2014 as compared to 2013.

Depreciation, Depletion, and Amortization Expenses. DD&A expense increased to \$43.1 million for the year ended December 31, 2014 from \$25.6 million in 2013. DD&A increased primarily due to higher production volumes and increased future development costs included in the 2014 year end reserve report. DD&A per Boe for 2014 was \$20.66 compared to \$16.69 in 2013. The increase in DD&A per BOE was due to higher future development cost offset by higher sales volumes in 2014 as compared to 2013.

Interest Expense. Interest expense decreased to \$2.6 million in 2014 from \$4.6 million for 2013. The decrease was primarily due to lower levels of debt during 2014 as compared to 2013.

Income Taxes. An income tax expense of \$0.7 million was recognized in 2013, which resulted in an overpayment of 2013 federal taxes. A credit of \$0.3 million was recognized in 2014 as a result of this overpayment. In 2013 approximately \$81,000 was recognized as a result of an audit of our 2009 federal income tax return. We incurred federal income tax of \$0.5 million and various state income taxes of approximately \$68,000 for the year ended December 31, 2013, primarily as a result of the gains realized on property sales during the year.

Loss (Gain) on Derivative Contracts. Gains or losses are determined by actual derivative settlements during the period and 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 in 2013 and 2014 consisted of fixed price swaps. The net estimated value of our commodity derivative contracts was an asset of approximately \$23.2 million as of December 31, 2014. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year ended December 31, 2014, we realized a gain on our derivative contracts of \$25.2 million, consisting of a gain of \$0.3 million on our closed contracts and a gain of \$24.9 million related to open contracts. For the year-ended December 31, 2013, we incurred a loss of \$2.5 million, consisting of a loss of \$5.0 million and a gain of \$2.5 million related to our open contracts.

Ceiling Limitation Write-Down. As of December 31, 2014 and 2013, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. 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 2014 which were \$95.28 per Bbl for oil and \$4.35 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

Gain on Sale of Oil and Gas Properties. The divestiture of our oil and gas properties in the Eagle Ford shale during the fourth quarter of 2013 resulted in a \$33.4 million gain due to its magnitude. Under Securities and Exchange Commission Regulation S-X, full cost accounting companies generally credit the full cost pool for proceeds from the sale of oil and gas properties. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. Due to the magnitude of this sale, there was a significant alteration of this relationship resulting in gain recognition. The basis of the properties sold was determined based on the relative fair value of the assets sold and assets retained.

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.

Operating Cash Flow. Our operating cash flow is sensitive to many variables, the most volatile of which is the prices of the oil, gas and NGL we produce and sell. Our consolidated cash flow from operations decreased in 2015 as a result of the significant decrease in commodity prices. In spite of this decline, we expect cash flow from operations to continue to be a primary source of liquidity as we adjust our capital program in response to lower commodity prices.

Commodity Prices. Prices are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors, which are difficult to predict, create volatility in prices and are beyond our control. We expect lower prices to continue throughout 2016. We have entered into fixed price commodity swaps and three-way collars on approximately 62% of our estimated oil production from our net proved developed producing reserves (as of December 31, 2015) through December 31, 2016 and 29% for 2017.

The key terms of our derivative financial instruments as of December 31, 2015 are presented in Note 11 in “Item 8. Financial Statements and Supplementary Data” of this report.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price decreases can lead to a decrease in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also decrease, causing a positive impact on our cash flow as the prices paid for services and equipment decline.

Working Capital (Deficit). At December 31, 2015, our current liabilities of \$35.1 million exceeded our current assets of \$32.7 million resulting in a working capital deficit of \$2.4 million. This compares to a working capital deficit of \$42.9 million at December 31, 2014. Current assets at December 31, 2015 primarily consisted of cash of \$3.5 million, accounts receivable of \$9.5 million and the current portion of our derivative asset of \$18.9 million. Current liabilities at December 31, 2015 primarily consisted of trade payables of \$24.8 million, revenues due third parties of \$7.2 million, current maturities of long-term debt of \$2.3 million and accrued expenses of \$0.7 million. The working capital deficit is expected to be funded by cash flow from operations and borrowings under our credit facility.

Capital Expenditures. Capital expenditures in 2013, 2014 and 2015 were \$92.5 million, \$192.8 million, and \$69.4 million, respectively. The table below sets forth the components of these capital expenditures:

	Year Ended December 31,		
	2013	2014	2015
	(In thousands)		
Expenditure category:			
Acquisition of producing properties	\$ —	\$ —	\$ —
Exploration/Development	91,324	189,210	68,631
Facilities and other	1,165	3,589	760
Total	<u>\$92,489</u>	<u>\$192,799</u>	<u>\$69,391</u>

During 2013, 2014 and 2015 our expenditures were primarily for development of our existing properties, as well as acquisitions of leaseholds.

We anticipate making capital expenditures in 2016 of approximately \$40.0 million. This budget assumes an improvement in commodity prices by the summer of 2016, and re-starting the Raven Rig #1. However, if commodity prices stay at current levels or decline further and we elect to keep the Raven Rig #1 idled, our capital expenditures could be approximately \$17.5 million which we intend to fund primarily with cash flows from operations. Substantially all of the \$17.5 million would be spent on completing previously drilled wells in the Bakken/Three Forks in the Rocky Mountain region. The 2016 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,		
	2013	2014	2015
	<i>(In thousands)</i>		
Net cash provided by operating activities	\$ 52,479	\$ 94,462	\$ 6,999
Net cash provided by (used in) investing activities	35,040	(186,800)	(69,253)
Net cash (used in) provided by financing activities	(84,389)	87,857	62,042
Total	<u>\$ 3,130</u>	<u>\$ (4,481)</u>	<u>\$ (212)</u>

Operating activities for the year ended December 31, 2015 provided \$7.0 million in cash. Non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used \$69.3 million. Financing activities provided \$62.0 million primarily from the proceeds from long term borrowings offset by payments on long-term borrowings.

Operating activities for the year ended December 31, 2014 provided \$94.5 million in cash. Non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used \$186.8 million. Financing activities provided \$87.9 million primarily from the issuance of equity in June 2014, and proceeds from long-term borrowings offset by payments on long-term debt.

Operating activities for the year ended December 31, 2013 provided \$52.5 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Investing activities provided \$35.0 million. Proceeds from the sale of oil and gas properties provided \$127.5 million which was offset by expenditures for the development of our oil and gas properties and leasehold acquisitions. Financing activities used \$84.4 million for the year ended December 31, 2013, primarily for the reduction of long-term debt.

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 would likely 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 availability under our credit facility is subject to a borrowing base determined by our lenders. This borrowing base is subject to semi-annual redeterminations. The next redetermination becomes effective on April 1, 2016. The risk of not finding commercially productive reservoirs will be compounded by the fact that 60% of our total estimated proved reserves on a BOE basis (19% on a PV-10 basis) at December 31, 2015 were classified as undeveloped.

We have in the past, and may, in the future, sell producing properties. We have also sold debt and equity securities in the past, and may sell additional debt and equity securities in the future when the opportunity presents itself.

On March 11, 2016 the Company monetized its fourth quarter fixed price derivative contracts. The proceeds from this monetization of approximately \$4.4 million will be used to pay down our credit facility.

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, 2015:

Contractual Obligations (In thousands)	Payments due in twelve month periods ending:				
	Total	December 31, 2016	December 31, 2017-2018	December 31, 2019-2020	Thereafter
Long-term debt ⁽¹⁾	\$140,732	\$2,330	\$135,047	\$ 558	\$2,797
Interest on long-term debt ⁽²⁾	10,871	4,156	6,184	266	265
Lease obligations ⁽³⁾	44	44	—	—	—
Total	<u>\$151,647</u>	<u>\$6,530</u>	<u>\$141,231</u>	<u>\$ 824</u>	<u>\$3,062</u>

(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 Dickinson, North Dakota, which expires on October 31, 2016, office space in Lusk, Wyoming, which will expire on December 31, 2016 and office space in Denver, Colorado which will expire on December 31, 2016.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2015, our reserve for these obligations totaled \$9.7 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2015, 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, 2015, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Long-Term Indebtedness.

Long-term debt consisted of the following:

	December 31, 2014	December 31, 2015
	(In thousands)	
Credit facility	\$70,000	\$134,000
Rig loan agreement	4,456	2,620
Real estate lien note	4,333	4,112
	<u>78,789</u>	<u>140,732</u>
Less current maturities	<u>(2,235)</u>	<u>(2,330)</u>
	<u>\$76,554</u>	<u>\$138,402</u>

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, 2015, \$134.0 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, 2015, we had a borrowing base of \$165.0 million. 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 next redetermination will be effective on April 1, 2016. Outstanding borrowings in excess of the borrowing base must be repaid immediately or we must pledge additional oil and gas properties or other assets as collateral. We do not currently have any substantial unpledged assets and we may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause us to fail to be in compliance with the financial covenants described below. 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 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) 0.75%—1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At December 31, 2015, the interest rate on the credit facility was 2.92% 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, 2018. 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. 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 defined as the sum of 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 plus expenses incurred in connection with the negotiation, execution, delivery and performance of the Credit Facility plus expenses incurred in connection with any acquisition permitted under the Credit Facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to \$1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses 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, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At December 31, 2015, we were in compliance with all of our debt covenants. As of December 31, 2015, the interest coverage ratio was 13.16 to 1.00, the total debt to EBITDAX ratio was 3.05 to 1.00, and our current ratio was 1.37 to 1.00.

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, secured by our Oilwell 2000 HP diesel electric drilling rig (the “Collateral”). The original principal amount of the note was \$7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of \$179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of December 31, 2014 and 2015, \$4.5 million and \$2.6 million, respectively, were 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

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest for five years at a fixed rate of 4.25% and is payable in monthly installments of \$34,354. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of December 31, 2014 and 2015, \$4.3 million and \$4.1 million, respectively, were 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 and three way collars on approximately 62% of our estimated oil production from our net proved developed producing reserves (as of December 31, 2015) through December 31, 2016 and 29% for 2017.

The Company’s derivative contracts consist of NYMEX-based fixed price swaps and three-way collar contracts. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Three-way collar contracts combine a long put, a short put and a short call. Under a collar, we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put). The use of the long put combined with a short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limits our exposure to future settlement payments while also restricting our downward risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle our contracts for the market price plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.

By removing a 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 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 gains on our commodity derivative contracts. For the year ended December 31, 2015, we incurred a gain of \$19.3 million,

consisting of a gain of \$9.5 million on our closed contracts and a gain of \$9.8 million related to our open contract positions. For the year ended December 31, 2014, we incurred a gain of \$25.2 million, consisting of a gain of \$0.3 million on closed contracts and a gain of \$24.9 million related to our open contract positions. For the year ended December 31, 2013, we incurred a net loss of \$2.5 million, consisting of a loss of \$5.0 million on our closed contracts and a gain of \$2.5 million related to our open contract positions. If the disparity between our contract prices and market prices continues, we will sustain gains or losses on our derivative contracts. While gains and losses resulting from the periodic mark to market of our open contracts do not impact our cash flow from operations, gains and losses from settlements of our closed contracts do impact our cash flow from operations. In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower. In addition, borrowings under our credit facility bear interest at floating rates. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

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

Net Operating Loss Carryforwards

At December 31, 2015, we had, subject to the limitation discussed below, \$192.9 million of net operating loss carryforward for tax purposes. The loss carryforward will expire through 2035, 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 \$103.7 million for deferred tax assets at December 31, 2015.

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. There were no related party transactions in 2014 or 2015.

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 Rule 4-10 and ASC 932 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. 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, 2013, 2014 and 2015 oil and gas prices were based on the average 12-month first-day-of-the-month pricing. 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. Gains or losses are determined by actual derivative settlements during the period and 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 a result, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. Our derivative contracts in 2015 consisted of commodity swaps and three way collars and fixed price swaps in 2013 and 2014. Due to the volatility of oil and gas prices, 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, 2014 and 2015, the net market value of our commodity derivatives was a net asset of \$23.2 million and \$27.4 million, respectively.

Share-Based Payments. We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Additional information about management's assumptions can be found in Note 5 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, 2013, 2014 and 2015, stock-based compensation was approximately \$2.1 million, \$2.7 million, and \$3.9 million, respectively.

New Accounting Standards and Disclosures

The Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") in May 2014 which provides accounting guidance for all revenue arising from contracts to provide goods or services to customers. The requirements from the new ASU are effective for interim and annual periods beginning after December 15, 2016, and early adoption is not permitted. The standard allows for either full retrospective adoption or modified retrospective adoption. At this time, we are evaluating the guidance to determine the method of adoption and the impact of this ASU on our financial statements and related disclosures, if any.

In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date ("ASU No. 2014-14") to defer the effective date of ASU No. 2014-09 by one year. Public business entities should apply the guidance in ASU 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim

The FASB issued ASU 2015-03, Interest – Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs and ASU 2015-15, Interest – Imputation of Interest (Topic 835): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements. These ASUs require debt issuance costs related to a recognized debt liability, except for those related to revolving credit facilities, to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability rather than as an asset. These ASUs are effective beginning January 1, 2016 and will be applied using the retrospective approach. These ASUs will not have a material impact on Abraxas's consolidated financial statements and related disclosures.

In August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", codifies an SEC staff announcement that entities are permitted to defer and present debt issuance costs related to line-of-credit arrangements as assets. The ASU clarifies that the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The ASU is effective immediately for both public business entities and non-public entities. Abraxas has elected to follow this presentation guidance.

The FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes. This ASU requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. This ASU is effective for annual and interim periods beginning in 2017 and can be applied prospectively or retrospectively, with early adoption permitted. This ASU will be adopted effective January 1, 2016 and will be applied using the retrospective approach. This ASU will not have an impact on Abraxas's consolidated financial statements and related disclosures.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments ("ASU No. 2015-16") to simplify the accounting for adjustments made to provisional amounts recognized in a business combination by eliminating the requirement to retrospectively account for those adjustments. The amendments under ASU No. 2015-16 require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment.

In February 2016, the FASB issued ASU 2016-02 "Leases," which supersedes ASC 840 "Leases" and creates a new topic, ASC 842 "Leases." This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified

retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are currently evaluating the effect of this update on our consolidated financial statements and related disclosures.

In August 2014, the FASB issued updated guidance related to determining whether substantial doubt exists about an entity's ability to continue as a going concern. The amendment provides guidance for determining whether conditions or events give rise to substantial doubt that an entity has the ability to continue as a going concern within one year following issuance of the financial statements, and requires specific disclosures regarding the conditions or events leading to substantial doubt. The updated guidance is effective for annual reporting periods and interim periods within those annual periods beginning after December 15, 2016. Earlier adoption is permitted. The Company does not expect the adoption of this guidance to have a material impact on its consolidated financial statements.

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, 2015, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flow by approximately \$6.7 million for the year. If commodity prices remain at their current levels the impact on operating revenues and cash flow, could be much more significant. However, we do have derivative contracts in place that will mitigate the impact of low commodity prices.

Derivative Instrument Sensitivity

At December 31, 2015, the aggregate fair market value of our commodity derivative contracts was an asset of approximately \$27.4 million. The fair market value of our commodity derivative contracts is sensitive to changes in the market price for oil and gas. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses.

For the year ended December 31, 2015, we recognized a gain of \$19.3 million, consisting of a gain of \$9.5 million on our closed contracts and a gain of \$9.8 million related to our open contract positions. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of December 31, 2015, we had \$134.0 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) 0.75%—1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At December 31, 2015, the interest rate on the credit facility was 2.92% based on 1-month LIBOR borrowings and level of utilization. An increase in the interest rate of 1% would increase our interest expense by \$1.3 million on an annual basis, based on the outstanding balance at December 31, 2015.

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, 2015 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.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2015 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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* (2013) 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, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by BDO USA, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

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 2016 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 Brian L. Melton., W. Dean Karrash, Paul A. Powell, Jr. and Jerry J. Langdon. 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 Brian L. Melton, 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 2014.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2016 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 2016 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 2016 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 2016 Annual Meeting of Stockholders which appears therein under the caption “Principal Auditor Fees and Services.”

PART IV

Item 15. Exhibits and 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.

<u>Exhibit Number</u>	<u>Description</u>
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 as Exhibit 3.6 to our Annual Report on Form 10-K filed on March 15, 2012).
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).
4.1	Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).
4.2	Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to our Annual Report on Form 10-K filed on March 31, 1995).
*10.1	Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to 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).
*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).

<u>Exhibit Number</u>	<u>Description</u>
*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 as Exhibit 10.9 to our Annual Report on Form 10-K filed March 18, 2013)
*10.10	Abraxas Petroleum Corporation Amended and Restated 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Appendix B to our Proxy Statement filed on April 2, 2015).
*10.11	Form of Stock Option Agreement under the Abraxas Petroleum Corporation Amended and Restated 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 Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. (Filed as Appendix A to our Proxy Statement filed on April 2, 2015).
*10.14	Form of Employee Stock Option Agreement under the Abraxas Petroleum Corporation Amended and Restated 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	Form of Restricted Stock Agreement under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan (Filed as Exhibit 10.1 to our Annual Report on Form 10-K filed on March 13, 2015).
10.16	Third Amended and Restated Credit Agreement dated as of June 11, 2014 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/A filed on June 13, 2014).
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).
10.18	Promissory Note dated November 13, 2008 by Abraxas Properties Incorporated and Abraxas Petroleum Corporation, payable to the order of Plains Capital Bank, as Lender. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on August 8, 2014.)
10.19	Second Modification, Renewal and Extension of Promissory Note and Deed of Trust Liens by and between Plains Capital Bank, Abraxas Properties Corporation and Abraxas Petroleum Corporation effective March 13, 2013. (Previously filed as Exhibit 10.2 to our Current Report on Form 8-K filed on August 8, 2014).
10.20	Third Modification, Renewal and Extension of Promissory Note and Deed of Trust Liens by and between Plains Capital Bank, Abraxas Properties Incorporated and Abraxas Petroleum Corporation effective as of July 13, 2013. (Previously filed as Exhibit 10.3 to our Current Report on Form 8-K filed on August 8, 2014).
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 herewith).
23.1	Consent of BDO USA, LLP. (Filed herewith).

<u>Exhibit Number</u>	<u>Description</u>
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
President and Principal
Executive Officer

By: /s/ Geoffrey R. King
Vice President and
Principal Financial Officer

By: /s/ G. William Krog, Jr.
Principal Accounting
Officer

DATED: March 15, 2016

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.

<u>Signature</u>	<u>Name and Title</u>	<u>Date</u>
<u>/s/ Robert L.G. Watson</u> Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	March 15, 2016
<u>/s/ Geoffrey R. King</u> Geoffrey R. King	Vice President, CFO (Principal Financial Officer)	March 15, 2016
<u>/s/ G. William Krog, Jr.</u> G. William Krog, Jr.	Chief Accounting Officer (Principal Accounting Officer)	March 15, 2016
<u>/s/ Harold D. Carter</u> Harold D. Carter	Director	March 15, 2016
<u>/s/ Ralph F. Cox</u> Ralph F. Cox	Director	March 15, 2016
<u>/s/ W. Dean Karrash</u> W. Dean Karrash	Director	March 15, 2016
<u>/s/ Jerry J. Langdon</u> Jerry J. Langdon	Director	March 15, 2016
<u>/s/ Dennis E. Logue</u> Dennis E. Logue	Director	March 15, 2016
<u>/s/ Brian L. Melton</u> Brian L. Melton	Director	March 15, 2016
<u>/s/ Paul A. Powell, Jr.</u> Paul A. Powell, Jr.	Director	March 15, 2016
<u>/s/ Edward P. Russell</u> Edward P. Russell	Director	March 15, 2016

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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, 2014 and 2015 and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2015. 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, 2014 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 15, 2016 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

San Antonio, Texas
March 15, 2016

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, 2015, based on criteria established in *Internal Control—Integrated Framework* (2013) 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, 2015, 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, 2014 and 2015, 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, 2015 and our report dated March 15, 2016 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

San Antonio, Texas
March 15, 2016

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
ASSETS

	December 31,	
	2014	2015
	(In thousands)	
Current assets:		
Cash and cash equivalents	\$ 3,772	\$ 3,540
Accounts receivable:		
Joint owners—net	5,648	1,552
Oil and gas production sales	15,308	6,713
Other	647	1,241
	21,603	9,506
Derivative assets	12,214	18,902
Other current assets	843	726
Total current assets	38,432	32,674
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	716,922	787,683
Other property and equipment	40,683	41,444
Total	757,605	829,127
Less accumulated depreciation, depletion, amortization and impairment	(434,726)	(604,289)
Total property and equipment, net	322,879	224,838
Deferred financing fees, net	2,216	1,642
Derivative asset	10,981	8,463
Other assets	391	255
Total assets	<u>\$ 374,899</u>	<u>\$ 267,872</u>

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS (CONTINUED)
LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31,	
	2014	2015
	(In thousands, except shares data)	
Current liabilities:		
Accounts payable	\$ 63,549	\$ 24,825
Joint interest oil and gas production payable	14,423	7,177
Accrued interest	72	115
Other accrued expenses	1,006	622
Derivative liability	13	—
Current maturities of long-term debt	2,235	2,330
Total current liabilities	81,298	35,069
Long-term debt—less current maturities	76,554	138,402
Other liabilities	57	257
Future site restoration	9,495	9,679
Total liabilities	167,404	183,407
Commitments and contingencies (Note 7)		
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 106,186,678 and 106,346,001, respectively	1,062	1,063
Additional paid-in capital	309,773	313,852
Accumulated deficit	(103,340)	(230,450)
Total stockholders' equity	207,495	84,465
Total liabilities and stockholders' equity	\$ 374,899	\$ 267,872

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2013	2014	2015
	(In thousands, except per share data)		
Revenues:			
Oil and gas production revenues	\$ 92,268	\$133,701	\$ 67,002
Other	56	75	28
	<u>92,324</u>	<u>133,776</u>	<u>67,030</u>
Operating costs and expenses:			
Lease operating	23,205	25,875	23,074
Production taxes	8,437	11,462	6,679
Depreciation, depletion, and amortization	25,588	43,139	38,721
Proved property impairment	—	—	128,573
General and administrative (including stock-based compensation of \$2,114, \$2,703 and \$3,912, respectively)	11,997	13,378	11,788
	<u>69,227</u>	<u>93,854</u>	<u>208,835</u>
Operating income (loss)	23,097	39,922	(141,805)
Other (income) expense:			
Interest income	(3)	(2)	(2)
Interest expense	4,556	2,570	3,906
Amortization of deferred financing fees	1,367	934	643
Gain on sale of properties	(33,377)	—	—
Loss (gain) on derivative contracts	2,474	(25,237)	(19,301)
Other	539	(7)	318
	<u>(24,444)</u>	<u>(21,742)</u>	<u>(14,436)</u>
Income (loss) from continuing operations before income tax	47,541	61,664	(127,369)
Income tax (expense) benefit	(700)	287	279
Net income (loss) from continuing operations	46,841	61,951	(127,090)
Net (loss) income from discontinued operations—net of tax	(8,194)	1,318	(20)
	<u>\$ 38,647</u>	<u>\$ 63,269</u>	<u>\$(127,110)</u>
Net income (loss) per common share—basic			
Continuing operations	\$ 0.51	\$ 0.63	\$ (1.21)
Discontinued operations	(0.09)	0.01	—
	<u>\$ 0.42</u>	<u>\$ 0.64</u>	<u>\$ (1.21)</u>
Net income (loss) per common share—diluted			
Continuing operations	\$ 0.50	\$ 0.61	\$ (1.21)
Discontinued operations	(0.09)	0.01	—
	<u>\$ 0.41</u>	<u>\$ 0.62</u>	<u>\$ (1.21)</u>

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2013	2014	2015
	(In thousands)		
Net income (loss)	\$38,647	\$63,269	\$(127,110)
Other comprehensive income (loss):			
Change in unrealized value of investments	(79)	—	—
Foreign currency translation adjustment	(559)	607	—
Other comprehensive income (loss)	(638)	607	—
Comprehensive income (loss)	<u>\$38,009</u>	<u>\$63,876</u>	<u>\$(127,110)</u>

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

(In thousands except number of shares)

	Common Stock		Additional Paid in Capital		Accumulated Deficit		Accumulated Other Comprehensive Income (Loss)		Total
	Shares	Amount	Amount						
Balance at December 31, 2012	92,733,448	\$ 927	\$250,998		\$(205,256)		\$ 31	\$ 46,700	
Net income	—	—	—		38,647		—	38,647	
Change in unrealized gain (loss) on fair value of investments	—	—	—		—		(79)	(79)	
Foreign currency translation adjustment	—	—	—		—		(559)	(559)	
Stock-based compensation	—	—	2,114		—		—	2,114	
Stock options exercised	129,686	2	81		—		—	83	
Restricted stock issued, net of cancellations	42,915	—	—		—		—	—	
Balance at December 31, 2013	92,906,049	929	253,193		(166,609)		(607)	86,906	
Net income	—	—	—		63,269		—	63,269	
Foreign currency translation adjustment	—	—	—		—		607	607	
Stock issuance	11,500,000	115	53,640		—		—	53,755	
Stock-based compensation	—	—	2,703		—		—	2,703	
Stock options exercised	238,157	3	252		—		—	255	
Restricted stock issued, net of cancellations	1,542,472	15	(15)		—		—	—	
Balance at December 31, 2014	106,186,678	1,062	309,773		(103,340)		—	207,495	
Net loss	—	—	—		(127,110)		—	(127,110)	
Stock-based compensation	—	—	3,912		—		—	3,912	
Stock options exercised	164,400	1	167		—		—	168	
Restricted stock issued, net of cancellations	(5,077)	—	—		—		—	—	
Balance at December 31, 2015	106,346,001	\$1,063	\$313,852		\$(230,450)		\$—	\$ 84,465	

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2013	2014	2015
	(In thousands)		
Operating Activities			
Net income (loss)	\$ 38,647	\$ 63,269	\$(127,110)
Income (loss) from discontinued operations	(8,194)	1,318	(20)
Income (loss) from continuing operations	46,841	61,951	(127,090)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Gain on sale of properties	(33,377)	—	—
Net gain on derivative contracts	2,494	(25,217)	(19,301)
Derivative contract settlements	(5,035)	361	9,495
Monetization of derivative contracts	—	152	4,610
Depreciation, depletion, and amortization	25,588	43,139	38,721
Proved property impairment	—	—	128,573
Accretion of future site restoration	615	559	565
Amortization of deferred financing fees	1,367	934	643
Stock-based compensation	2,114	2,703	3,912
Changes in operating assets and liabilities:			
Accounts receivable—net of allowance	(13,702)	11,881	12,097
Other assets and liabilities	(7)	(2,737)	1,466
Accounts payable	27,514	1,596	(45,970)
Accrued expenses	(1,933)	(860)	(722)
Net cash provided by continuing operations	52,479	94,462	6,999
Net cash (used in) provided by discontinued operations	(825)	1,741	(20)
Net cash provided by operating activities	51,654	96,203	6,979
Investing Activities			
Capital expenditures, including purchases and development of properties	(92,489)	(192,799)	(69,391)
Proceeds from the sale of oil and gas properties	127,529	5,999	138
Net cash provided by (used in) continuing operations	35,040	(186,800)	(69,253)
Net cash (used in) provided by discontinued operations	(2,554)	332	—
Net cash provided by (used in) investing activities	32,486	(186,468)	(69,253)
Financing Activities			
Proceeds from exercise of stock options	83	255	168
Proceeds from issuance of common stock, net of offering costs	—	53,755	—
Proceeds from long-term borrowings	42,000	82,000	68,007
Payments on long-term borrowings	(122,826)	(47,143)	(6,064)
Deferred financing fees	(110)	(1,010)	(69)
Other	(3,536)	—	—
Net cash (used in) provided by continuing operations	(84,389)	87,857	62,042
Net cash provided by discontinued operations	3,375	975	—
Net cash (used in) provided by financing activities	(81,014)	88,832	62,042
Effect of exchange rate changes on cash—discontinued operations	18	—	—
Increase (decrease) in cash	3,144	(1,433)	(232)
Cash at beginning of year	2,061	5,205	3,772
Cash at end of year	\$ 5,205	\$ 3,772	\$ 3,540

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(CONTINUED)

	Years Ended December 31,		
	2013	2014	2015
	(In thousands)		
Supplemental disclosures of cash flow information:			
Interest paid	\$ 3,986	\$ 1,970	\$ 3,298
Income taxes paid	\$ 391	\$ —	\$ —
Non-cash investing activities:			
Asset retirement obligation cost and liabilities	<u>\$ 138</u>	<u>\$ 198</u>	<u>\$ 30</u>
Asset retirement obligations associated with property acquisitions and dispositions	<u>\$ (1,890)</u>	<u>\$ (406)</u>	<u>\$ 410</u>

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Significant Accounting Policies

Nature of Operations

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

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”).

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.

The process of estimating oil and gas reserves in accordance with SEC requirements 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 most significant estimates pertain to proved oil, natural gas and NGLs reserves and related cash flow estimates used in impairment tests of oil and gas properties, the fair value of assets and liabilities acquired in business combinations, derivative contracts, asset retirement obligations, accrued oil and gas revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

Reclassification of prior period balances

Certain amounts in the prior periods presented have been reclassified to conform to the current year financial statement presentation. These reclassifications have no effect on previously reported net income.

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 \$407,000 and \$296,000 at December 31, 2014 and 2015, 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.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and gas with all of the Company's operational activities having been conducted in the U.S. The Company's current operational activities and the Company's consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long lived assets located outside the U.S.

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 for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. For the years ended December 31, 2013 and 2014, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. For the year ended December 31, 2015, our capitalized cost of oil and gas properties exceeded the present value of our estimated proved reserves by \$128.6 million, resulting in the recognition of a proved property impairment of \$128.6 million. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges.

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 unweighted average 12 month first-day-of-month pricing. 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 and three way collars, which limit the impact of price fluctuations with respect to the Company's sale of oil and gas. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions could arise where actual production is less than estimated which could, result in overhedged volumes.

All derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The derivative instruments the Company utilizes are based on index prices that may and often do differ from the actual oil and gas prices realized in its 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, the Company does not account for its derivative instruments as cash flow hedges for financial reporting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in net gains (losses) on commodity derivative contracts in the Consolidated Statements of Operations.

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

Options granted are valued at the date of grant and expense is recognized over the vesting period. The Company currently utilizes a standard option pricing model (Black-Scholes) to measure the fair value of stock options granted to employees and directors. 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, 2013, 2014 and 2015, stock-based compensation was approximately \$2.1 million, \$2.7 million and \$3.9 million, respectively.

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

The 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. Each year, the Company reviews, and to the extent necessary, revises its asset retirement obligation estimates.

The following table summarizes the Company's asset retirement obligations during the two years ended December 31:

	<u>2014</u>	<u>2015</u>
	<u>(in thousands)</u>	
Beginning asset retirement obligation	\$ 9,888	\$9,495
New wells placed on production and other	444	307
Deletions related to property disposals and plugging costs	(1,318)	(793)
Accretion expense	559	565
Revisions	198	105
Discontinued operations	(276)	—
Ending asset retirement obligation	<u>\$ 9,495</u>	<u>\$9,679</u>

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, 2014 and 2015.

During 2013, two purchasers accounted for 49% of oil and gas revenues. During 2014, two purchasers accounted for 62% of oil and gas revenues. During 2015, one customer accounted for 54% of our 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

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 with respect 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. Therefore, we have established a valuation allowance of \$103.7 million for deferred tax assets at December 31, 2015.

Accounting for Uncertainty in Income Taxes

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

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

likely-than-not criteria should be de-recognized in the first subsequent reporting period in which the threshold is no longer met. Penalties and interest are classified as income tax expense.

New Accounting Standards and Disclosures

The Financial Accounting Standards Board (“FASB”) issued an Accounting Standards Update (“ASU”) in May 2014 which provides accounting guidance for all revenue arising from contracts to provide goods or services to customers. The requirements from the new ASU are effective for interim and annual periods beginning after December 15, 2016, and early adoption is not permitted. The standard allows for either full retrospective adoption or modified retrospective adoption. At this time, we are evaluating the guidance to determine the method of adoption and the impact of this ASU on our financial statements and related disclosures, if any.

In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date (“ASU No. 2014-14”) to defer the effective date of ASU No. 2014-09 by one year. Public business entities should apply the guidance in ASU 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim

The FASB issued ASU 2015-03, Interest—Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs and ASU 2015-15, Interest—Imputation of Interest (Topic 835): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements. These ASUs require debt issuance costs related to a recognized debt liability, except for those related to revolving credit facilities, to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability rather than as an asset. These ASUs are effective beginning January 1, 2016 and will be applied using the retrospective approach. These ASUs will not have a material impact on Abraxas’s consolidated financial statements and related disclosures.

In August 2015, the FASB issued ASU 2015-15, “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements”, codifies an SEC staff announcement that entities are permitted to defer and present debt issuance costs related to line-of-credit arrangements as assets. The ASU clarifies that the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The ASU is effective immediately for both public business entities and non-public entities. Abraxas has elected to follow this presentation guidance.

The FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes. This ASU requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. This ASU is effective for annual and interim periods beginning in 2017 and can be applied prospectively or retrospectively, with early adoption permitted. This ASU will be adopted effective January 1, 2016 and will be applied using the retrospective approach. This ASU will not have an impact on Abraxas’s consolidated financial statements and related disclosures.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments (“ASU No. 2015-16”) to simplify the accounting for adjustments made to provisional amounts recognized in a business combination by eliminating the requirement to retrospectively account for those adjustments. The amendments under ASU No. 2015-16 require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment

In February 2016, the FASB issued ASU 2016-02 “Leases,” which supersedes ASC 840 “Leases” and creates a new topic, ASC 842 “Leases.” This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are currently evaluating the effect of this update on our consolidated financial statements and related disclosures.

In August 2014, the FASB issued updated guidance related to determining whether substantial doubt exists about an entity’s ability to continue as a going concern. The amendment provides guidance for determining whether conditions or

events give rise to substantial doubt that an entity has the ability to continue as a going concern within one year following issuance of the financial statements, and requires specific disclosures regarding the conditions or events leading to substantial doubt. The updated guidance is effective for annual reporting periods and interim periods within those annual periods beginning after December 15, 2016. Earlier adoption is permitted. The Company does not expect the adoption of this guidance to have a material impact on its consolidated financial statements.

2. Divestiture of Properties

Beginning in the third quarter of 2012 and continuing through the present, the Company's business plan has been to divest various properties considered non-core, and primarily non-operated to focus on its core basins in the Eagle Ford, Bakken, Powder River Basin and Permian Basin.

In August 2013 the Company's non-operated properties in the Bakken were sold for net proceeds of \$38.3 million. In December 2013, the Company closed on the divestiture of its non-operated position in the Wycross area of the Eagle Ford for net proceeds of \$71.4 million. Other property sales during 2013 netted \$0.6 million. In the first quarter of 2014 the Company sold several non-core Permian Basin and Gulf Coast properties for combined proceeds of \$2.6 million. In the second quarter of 2014 the Company sold a non-core Permian Basin property for net proceeds of \$2.5 million. Other non-core asset sales during 2014 netted \$0.9 million. There were no significant property sales in 2015.

The net proceeds were used to repay outstanding indebtedness under the Company's credit facility, for capital expenditures and general corporate purposes. Proceeds from these sales, except for the Wycross sale, were credited to the full cost pool as these sales were not significant under full cost accounting rules. Due to the magnitude of the Wycross sale and its impact on the relationship of capitalized costs and reserves, a gain of \$33.4 million was recognized in 2013.

3. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2014 and 2015, respectively:

	December 31, 2014	December 31, 2015
	(In thousands)	
Senior secured credit facility	\$70,000	\$134,000
Rig loan agreement	4,456	2,620
Real estate lien note	4,333	4,112
	78,789	140,732
Less current maturities	(2,235)	(2,330)
	<u>\$76,554</u>	<u>\$138,402</u>

Maturities of long-term debt are as follows:

Year ending December 31, (In thousands)	
2016	\$ 2,330
2017	786
2018	134,262
2019	273
2020	285
Thereafter	2,796
	<u>\$140,732</u>

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, 2015, \$134.0 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, 2015, we had a borrowing base of \$165.0 million. 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 next redetermination will be effective on April 1, 2016. Outstanding borrowings in excess of the borrowing base must be repaid immediately or we must pledge additional oil and gas properties or other assets as collateral. We do not currently have any substantial unpledged assets and we may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause us to fail to be in compliance with the financial covenants described below. 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 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) 0.75%—1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At December 31, 2015, the interest rate on the credit facility was 2.92% 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, 2018. 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. 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 Hedging, 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. 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 defined as the sum of 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 plus expenses incurred in connection with the negotiation, execution, delivery and performance of the Credit Facility plus expenses incurred in connection with any acquisition permitted under the Credit Facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to \$1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses 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, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At December 31, 2015 we were in compliance with all of our debt covenants. As of December 31, 2015, the interest coverage ratio was 13.16 to 1.00, the total debt to EBITDAX ratio was 3.05 to 1.00, and our current ratio was 1.37 to 1.00.

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, secured by our Oilwell 2000 HP diesel electric drilling rig (the “Collateral”). The original principal amount of the note was \$7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of \$179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of December 31, 2014 and 2015, \$4.5 million and \$2.6 million, respectively, were 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

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest for five years at a fixed rate of 4.25% and is payable in monthly installments of \$34,354. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of December 31, 2014 and 2015, \$4.3 million and \$4.1 million, respectively, were outstanding on the note.

4. Property and Equipment

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

	Estimated Useful Life	December 31,	
	Years	2014	2015
		(In thousands)	
Oil and gas properties	—	\$716,922	\$787,683
Equipment and other	3-39	18,608	18,866
Drilling rig	15	22,075	22,578
		<u>\$757,605</u>	<u>\$829,127</u>

5. Stock-Based Compensation and Option Plans

Stock Options

The Company’s 2005 Amended and Restated Employee Long-Term Equity Incentive Plan reserves 6.6 million shares of Abraxas common stock, subject to adjustment following certain events. Awards may be in options or shares of restricted stock. 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 Company utilizes a standard option pricing model (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 2013, 2014 and 2015:

	<u>2013</u>	<u>2014</u>	<u>2015</u>
Weighted average value per option granted during the period	\$ 1.73	\$ 2.44	\$ 2.37
Assumptions:			
Forfeiture rate ⁽¹⁾	4.1%	4.2%	4.5%
Expected dividend yield ⁽²⁾	—%	—%	—%
Volatility ⁽³⁾	81.2%	80.7%	81.1%
Risk free interest rate ⁽⁴⁾	1.24%	2.05%	1.92%
Expected life (years) ⁽⁵⁾	6.5	6.6	7.0
Fair value of options granted (in thousands)	\$1,444	\$2,666	\$3,792

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

(2) The dividend yield is based on the fact the Company does not pay any dividends.

(3) The volatility is based on the historical volatility of our stock for a period approximating the expected life.

(4) The risk-free interest rate is based on the observed U.S. Treasury yield curve in effect at the time the options were granted.

(5) The expected life was derived based on a weighting between (a) the Company's historical exercise and forfeiture activity and (b) the average midpoint between vesting and the contractual term.

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

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

	<u>Options (000s)</u>	<u>Weighted average exercise price</u>	<u>Weighted average remaining life</u>	<u>Intrinsic value per share</u>
Options outstanding December 31, 2012	4,761	\$2.77		
Granted	836	2.43		
Exercised	(166)	1.18		
Forfeited/Expired	(31)	2.58		
Options outstanding December 31, 2013	5,400	\$2.77		
Granted	1,091	3.38		
Exercised	(410)	2.71		
Forfeited/Expired	(196)	3.08		
Options outstanding December 31, 2014	5,885	\$2.88		
Granted	1,601	\$3.22		
Exercised	(164)	1.03		
Forfeited/Expired	(514)	4.36		
Options outstanding December 31, 2015	<u>6,808</u>	<u>\$2.89</u>	<u>6.4</u>	<u>\$2.06</u>
Exercisable at end of year	<u>4,305</u>		<u>5.1</u>	<u>\$1.97</u>

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

	<u>2013</u>	<u>2014</u>	<u>2015</u>
Weighted average grant date fair value of stock options granted (per share)	\$ 1.73	\$ 2.44	\$ 2.37
Total fair value of options vested (000's)	\$1,670	\$1,718	\$2,035
Total intrinsic value of options exercised (000's)	\$ 275	\$ 932	\$ 124

As of December 31, 2015, the total compensation cost related to non-vested awards not yet recognized was approximately \$3.8 million, which will be recognized in 2016 through 2019. For the years ended December 31, 2013, 2014 and 2015, we recognized \$1.7 million, \$1.8 million and \$2.4 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, 2015:

	Options outstanding			Exercisable		
	Number outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable	Weighted average remaining life	Weighted average exercise price
0.99 – 1.99	1,519,079	3.99	\$1.54	1,469,079	3.90	\$1.52
2.00 – 2.99	1,374,300	6.11	\$2.34	1,073,104	5.76	\$2.32
3.00 – 3.99	3,068,600	8.05	\$3.29	936,795	6.39	\$3.53
4.00 – 4.99	675,750		\$4.57	659,250	4.70	\$4.58
5.00 – 5.99	99,000	8.36	\$5.39	96,750	8.35	\$5.38
6.00 – 6.28	71,000	0.26	\$6.05	70,250	0.18	\$6.05
	<u>6,807,729</u>			<u>4,305,228</u>		

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, 2015, the total compensation cost related to non-vested awards not yet recognized was approximately \$3.3 million, which will be recognized in 2016 through 2019. For the years ended December 31, 2013, 2014 and 2015, we recognized \$0.4 million, \$0.9 million and \$1.5 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:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2012	482,025	\$ 3.09
Granted	48,222	2.69
Vested/Released	(169,700)	2.66
Forfeited	(5,307)	3.08
Unvested December 31, 2013	355,240	\$ 3.24
Granted	1,582,000	3.49
Vested/Released	(121,622)	3.64
Forfeited	(39,528)	3.44
Unvested December 31, 2014	1,776,090	\$ 3.43
Granted	—	—
Vested/Released	(127,729)	3.38
Forfeited	(5,077)	2.56
Unvested December 31, 2015	<u>1,643,284</u>	<u>\$ 3.44</u>

Director Stock Awards

Shares Reserved and Awards. The 2005 Directors Plan (as amended and restated) reserves 1.9 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 25,000 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, between April 2011 and April 2012, directors were compensated for their annual retainer fee of \$27,500 in cash. In April 2012 the retainer fee was increased to \$40,000 and remained at \$40,000 through 2015. Beginning in 2016, the retainer fee will be reduced by 20% and paid one half in cash and one half in Abraxas common stock. The retainer fee for 2016 is \$32,000.

At December 31, 2015, the Company had approximately 8.7 million shares reserved for future issuance for conversion of its stock options, and incentive plans for the Company's directors, employees and consultants.

6. 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,		
	2013	2014	2015
	(In thousands)		
Deferred tax liabilities:			
Hedge contracts	\$ —	\$ 8,114	\$ 9,578
Other	3,152	4,458	4,042
Total deferred tax liabilities	3,152	12,572	13,620
Deferred tax assets:			
U.S. full cost pool	11,725	3,352	35,689
Canada full cost pool	4,081	—	—
Capital loss carryforward	—	12,325	7,767
Depletion carryforward	4,743	4,936	5,558
U.S. net operating loss carryforward	49,667	50,941	67,531
Canada net operating loss carryforward	5,736	—	—
Alternative minimum tax credit	1,369	1,104	757
Hedge contracts	1,397	—	—
Total deferred tax assets	78,718	72,658	117,302
Valuation allowance for deferred tax assets	(75,566)	(60,086)	(103,682)
Net deferred tax assets	3,152	12,572	13,620
Net deferred tax	\$ —	\$ —	\$ —

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

	Years ended December 31,		
	2013	2014	2015
	(In thousands)		
Current:			
Federal	\$632	\$(276)	\$(242)
State	68	(11)	(37)
	<u>\$700</u>	<u>\$(287)</u>	<u>\$(279)</u>
Deferred:			
Federal	\$—	\$—	\$—
Foreign	—	—	—
	<u>\$—</u>	<u>\$—</u>	<u>\$—</u>

At December 31, 2015, the Company had, subject to the limitation discussed below, \$192.9 million of net operating loss carryforwards for U.S. tax purposes. The U.S. federal loss carryforward will expire in varying amounts through 2035, if not utilized.

The use of our net operating loss carryforwards will be limited if there is an "ownership change" in our common stock, generally a cumulative ownership change exceeding 50% during a three year period, as determined under Section 382 of the Internal Revenue Code. As of December 31, 2015, we have not had an ownership change as defined by Section 382. In addition to any Section 382 limitations, uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, the Company has established a valuation allowance of \$75.6 million at December 31, 2013, \$60.1 million at December 31, 2014 and \$103.7 million at December 31, 2015.

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

	Years ended December 31,		
	2013	2014	2015
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	\$(13,771)	\$(22,044)	\$ 44,586
(Increase) decrease in deferred tax asset valuation allowance	14,146	15,480	(43,596)
Alternative minimum tax	—	—	568
Rate differential for non US income	(574)	(39)	—
State income taxes	(47)	—	—
Accrual of prior year federal taxes (2009 and 2013)	(81)	287	37
Permanent differences	(743)	(950)	(1,371)
Return to provision estimate revision	—	4,562	—
Tax benefit related to the sale of Canadian subsidiary	—	3,501	—
Increase in asset for partnership distribution	—	—	—
Other	370	(510)	55
	<u>\$ (700)</u>	<u>\$ 287</u>	<u>\$ 279</u>

During 2015, the Company increased deferred tax assets by \$44.6 million related to increases in the full cost pool assets and net operating loss carryforward offset by a decrease in the net capital loss carryforward. The deferred tax assets were fully offset by a valuation allowance which was reduced at the same time.

As of December 31, 2015, 2014 and 2013, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2012 through 2015 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. 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. On July 23, 2013, we settled the assessment for \$391,000 resulting in \$81,000 being recognized as expense in 2013.

7. Commitments and Contingencies

Operating Leases

The Company leases office space in Dickinson, North Dakota, Lusk, Wyoming and Denver, Colorado. During 2013, 2014 and 2015, rent expense incurred for the Dickinson, North Dakota office was \$26,073, \$26,265, and \$27,165, respectively. The lease expires on October 31, 2016. Rent expense incurred for the Lusk, Wyoming office for 2013, 2014 and 2015 was \$9,000 for each year. The lease expires on December 31, 2016. In 2013 the Company leased office space in Denver, Colorado, rent expense incurred on this lease was \$2,834, \$14,554 and \$15,601 for 2013, 2014 and 2015, respectively. The lease expires on December 31, 2016.

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, 2015, 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.

8. Earnings per Share

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

	Years ended December 31:		
	2013	2014	2015
	(In thousands, except per share data)		
Numerator:			
Net income (loss) from continuing operations	\$46,841	\$ 61,951	\$(127,090)
Net (loss) income from discontinued operations	(8,194)	1,318	(20)
	<u>\$38,647</u>	<u>\$ 63,269</u>	<u>\$(127,110)</u>
Denominator:			
Denominator for basic earnings per share – weighted-average common shares outstanding	92,451	98,835	104,605
Effect of dilutive securities:			
Stock options and restricted shares	<u>1,087</u>	<u>2,633</u>	<u>—</u>
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options and restricted shares	<u>93,538</u>	<u>101,468</u>	<u>104,605</u>
Net income (loss) per common share—basic			
Continuing operations	\$ 0.51	\$ 0.63	\$ (1.21)
Discontinued operations	<u>(0.09)</u>	<u>0.01</u>	<u>—</u>
	<u>\$ 0.42</u>	<u>\$ 0.64</u>	<u>\$ (1.21)</u>
Net income (loss) per common share—diluted			
Continuing operations	\$ 0.50	\$ 0.61	\$ (1.21)
Discontinued operations	<u>(0.09)</u>	<u>0.01</u>	<u>—</u>
	<u>\$ 0.41</u>	<u>\$ 0.62</u>	<u>\$ (1.21)</u>

Basic earnings per share, excluding any dilutive effects of stock options 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, 2015, 624 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, 2013 and 2014.

9. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2014 and 2015 are as follows:

	1 st Quarter	2 nd Quarter	3 rd Quarter	4 th Quarter
	(In thousands, except per share data)			
<u>Year Ended December 31, 2014</u>				
Net revenue	\$25,518	\$33,192	\$ 43,874	\$ 31,192
Operating income	\$ 7,695	\$12,603	\$ 16,783	\$ 2,842
Net income	\$ 4,704	\$ 3,034	\$ 25,399	\$ 30,132
Net income per common share—basic	\$ 0.05	\$ 0.03	\$ 0.24	\$ 0.29
Net income per common share—diluted	\$ 0.05	\$ 0.03	\$ 0.24	\$ 0.28
<u>Year Ended December 31, 2015</u>				
Net revenue	\$18,661	\$18,944	\$ 16,077	\$ 13,348
Operating loss	\$(4,535)	\$(1,531)	\$(63,438)	\$(72,301)
Net loss	\$ (718)	\$(6,601)	\$(52,372)	\$(67,419)
Net loss per common share—basic	\$ (0.01)	\$ (0.06)	\$ (0.50)	\$ (0.64)
Net loss per common share—diluted	\$ (0.01)	\$ (0.06)	\$ (0.50)	\$ (0.64)

10. Benefit Plans

The Company has a defined contribution plan (401(k) plan) covering all eligible employees. In 2013, 2014 and 2015, in accordance with the safe harbor provisions of the plan, the Company contributed \$284,865, \$313,899 and \$347,632, 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 2013 and 2014 was \$17,500 for employees under the age of 50 and \$23,000 for employees 50 years of age or older. The 2015 employee contribution limit was \$18,000 for employees under the age of 50 and \$24,000 for employees 50 years of age or older.

11. 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. There are no netting agreements relating to these derivative contracts and there is no policy to offset.

The following table sets forth the summary position of our derivative contracts as of December 31, 2015:

Fixed Price Swaps:

<u>Contract Periods</u>	<u>Oil—WTI</u>	
	<u>Daily Volume (Bbl)</u>	<u>Swap Price (per Bbl)</u>
2016	948	\$84.10
2017	608	\$78.55

Collar contracts combined with short puts (three-way collar):

	<u>Daily Volume (Bbl)</u>	<u>Floor (Long Put)</u>	<u>Ceiling (Short Call)</u>	<u>Short Put</u>
2016	1,000	\$60.00	\$71.00	\$45.00

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

<u>Fair Value of Derivative Instruments as of December 31, 2014</u>				
<u>Derivatives not designated as hedging instruments</u>	<u>Asset Derivatives</u>		<u>Liability Derivatives</u>	
	<u>Balance Sheet Location</u>	<u>Fair Value</u>	<u>Balance Sheet Location</u>	<u>Fair Value</u>
Commodity price derivatives	Derivatives—current	\$12,214	Derivatives—current	\$ 13
Commodity price derivatives	Derivatives—long-term	10,981	Derivatives—long-term	—
		<u>\$23,195</u>		<u>\$ 13</u>
<u>Fair Value of Derivative Instruments as of December 31, 2015</u>				
<u>Derivatives not designated as hedging instruments</u>	<u>Asset Derivatives</u>		<u>Liability Derivatives</u>	
	<u>Balance Sheet Location</u>	<u>Fair Value</u>	<u>Balance Sheet Location</u>	<u>Fair Value</u>
Commodity price derivatives	Derivatives—current	\$18,902	Derivatives—current	\$—
Commodity price derivatives	Derivatives—long-term	8,463	Derivatives—long-term	—
		<u>\$27,365</u>		<u>\$—</u>

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

12. Financial Instruments

There is 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, 2014 and 2015, 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, 2014
Assets:				
NYMEX Fixed Price Derivative contracts	\$—	\$23,195	\$—	\$23,195
Total Assets	<u>\$—</u>	<u>\$23,195</u>	<u>\$—</u>	<u>\$23,195</u>
Liabilities:				
NYMEX Fixed Price Derivative contracts	\$—	\$ 13	\$—	\$ 13
Total Liabilities	<u>\$—</u>	<u>\$ 13</u>	<u>\$—</u>	<u>\$ 13</u>

	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, 2015
Assets:				
NYMEX Fixed Price Derivative contracts	\$—	\$21,731	\$ —	\$21,731
NYMEX Collars	—	—	5,634	5,634
Total Assets	<u>\$—</u>	<u>\$21,731</u>	<u>\$5,634</u>	<u>\$27,365</u>
Liabilities:				
NYMEX Fixed Price Derivative contracts	\$—	\$ —	\$ —	\$ —
Total Liabilities	<u>\$—</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

The Company's derivative contracts consist of NYMEX-based fixed price commodity swaps and NYMEX collars. 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. The fair value of the collar instruments are based on inputs that are not as observable as the fixed price swaps. In addition to the actively quoted market price, variables such as time value, volatility and other unobservable inputs are used. Accordingly, these instruments have been classified as Level 3.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the year ended December 31, 2015.

	(In thousands)
Unobservable inputs at January 1, 2015	\$ —
Changes in market value	8,474
Settlements during the period	(2,840)
Unobservable inputs at December 31, 2015	<u>\$ 5,634</u>

Nonrecurring Fair Value Measurements

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. As it relates to the Company, ASC 820-10 applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligation is presented in Note 1.

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.

13. Discontinued Operations

On October 31, 2014, the Company closed on the sale of its Canadian subsidiary, Canadian Abraxas Petroleum, ULC ("Canadian Abraxas"). The sale was based on management's decision to discontinue Canadian operations due to continuing losses.

In 2014, the Company recognized a gain on the sale of \$1.9 million which is included in the accompanying Consolidated Statements of Operations as a component of net (loss) income from discontinued operations, net of tax.

Canadian Abraxas revenue, reported in discontinued operations for the ten months ended October 31, 2014, and for the year ended December 31, 2013 was \$1.2 million and \$2.0 million, respectively. Canadian Abraxas net loss, reported in discontinued operations for the ten months ended October 31, 2014 and year ended December 31, 2013 was \$0.6 million and \$8.2 million, respectively.

The following is a summary of the net assets of Canadian Abraxas as of October 31, 2014.

	<u>October 31, 2014</u>
Current assets	\$ 252
Oil and gas properties—net	659
Other assets	—
Total assets	911
Accounts payable	275
Accrued expenses	280
Total liabilities	555
Net assets of discontinued operation	<u>\$ 356</u>

14. Subsequent Event

On March 11, 2016 the Company monetized its fourth quarter fixed price derivative contracts. The proceeds from this monetization of approximately \$4.4 million will be used to pay down our credit facility. Simultaneously, the Company entered into new fixed price swaps as follows:

<u>Contract Periods</u>	<u>Daily Volume (Bbl)</u>	<u>Swap Price (per Bbl)</u>
2016 (October—December)	2,500	\$43.25
2017	1,300	\$44.55
2018	1,500	\$46.39

15. Supplemental Oil and Gas Disclosures (Unaudited)

Information in the following tables is inclusive of Canadian operations through October 2014, which are presented in the basic financial statements as discontinued operations.

The accompanying table presents information concerning the Company's oil and gas producing activities inclusive of discontinued operations "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows:

	<u>Years Ended December 31</u>	
	<u>2014</u>	<u>2015</u>
	<u>(In thousands)</u>	
Proved oil and gas properties	\$ 716,922	\$ 787,683
Unproved properties	—	—
Total	716,922	787,683
Accumulated depreciation, depletion, amortization and impairment	(423,819)	(590,432)
Net capitalized costs	<u>\$ 293,103</u>	<u>\$ 197,251</u>

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

	<u>Years Ended December 31</u>		
	<u>2013</u>	<u>2014</u>	<u>2015</u>
	<u>(In thousands)</u>		
Development costs	\$93,878	\$189,322	\$68,631
Exploration costs	—	—	—
Property acquisition costs	—	—	—
Unproved	—	—	—
	<u>\$93,878</u>	<u>\$189,322</u>	<u>\$68,631</u>

The results of operations for oil and gas producing activities, inclusive of discontinued operations, for the three years ended December 31, 2013, 2014 and 2015 are as follows:

	<u>Years Ended December 31,</u>		
	<u>2013</u>	<u>2014</u>	<u>2015</u>
	<u>(In thousands)</u>		
Revenues	\$ 94,275	\$134,883	\$ 67,002
Production costs	(33,871)	(38,146)	(29,753)
Depreciation, depletion, and amortization	(26,072)	(42,945)	(38,040)
Proved property impairment	(6,025)	—	(128,573)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	<u>\$ 28,307</u>	<u>\$ 53,792</u>	<u>\$(129,364)</u>
Depletion rate per barrel of oil equivalent	<u>\$ 16.59</u>	<u>\$ 20.39</u>	<u>\$ 17.44</u>

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, 2013, 2014, and 2015. Reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been predominately prepared by independent petroleum reserve engineers. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company's proved reserves are located in the continental United States.

Proved reserves were estimated in accordance with guidelines established by the 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 unweighted 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.

For the period ending December 31, 2015, proved producing reserves decreased by approximately 6.6 MMBOE, net, due primarily to shortened economic lives resulting from lower product price forecasts.

The Company added 28 new proved undeveloped Bakken locations during 2015 on the Company's prospect acreage in McKenzie County, North Dakota, accounting for approximately 6.5 MMBOE of net reserves, 20 of which are in the Three Forks (second bench) locations which were proved during 2015 by local development results. There were also 8 downspaced locations added on the Yellowstone Unit by virtue of the fact that operatorship of that unit should pass to Abraxas, thereby allowing the implementation of the Company's standard Bakken spacing plan.

The Company also gained proved undeveloped reserves of approximately 1.4 MMBOE net, due to the change in classification of 21 probable and possible undeveloped Bakken cases into the proved category. These locations achieved proved status by virtue of offsetting development activity during 2015. An equivalent volume of reserves was removed from the probable and possible undeveloped category as a result of this change in classification.

The Company also added 6 new Montoya proved undeveloped locations on the Company's prospect acreage in Ward County, Texas. These locations were added based on the performance of existing Montoya producers on the subject leasehold. Net reserves of approximately 6.5 MMBOE are attributable to these new locations.

The Company dropped 38 South Texas Eagle Ford proved undeveloped cases from its reserve report due to lack of economic viability at the lower commodity prices. These cases represented approximately 7.8 MMBOE of net reserves.

	<u>Oil</u>	<u>NGL</u>	<u>Gas</u>	<u>Oil</u>
	<u>(MBbl)</u>	<u>(MBbl)</u>	<u>(MMcf)</u>	<u>Equivalents</u>
				<u>(MBoe)</u>
Proved developed and undeveloped reserves:				
Balance at December 31, 2012	17,342	2,614	61,184	30,152
Revisions of previous estimates	797	202	(5,123)	145
Extensions and discoveries	10,411	335	3,610	11,348
Sales of minerals in place	(6,785)	(963)	(8,141)	(9,105)
Production	(850)	(150)	(3,421)	(1,570)
Balance at December 31, 2013	20,915	2,038	48,109	30,970
Revisions of previous estimates	2,697	1,021	7,383	4,950
Extensions and discoveries	7,780	868	6,893	9,797
Sales of minerals in place	(608)	(12)	(3,614)	(1,223)
Production	(1,394)	(207)	(2,918)	(2,088)
Balance at December 31, 2014	29,390	3,708	55,853	42,406
Revisions of previous estimates	(9,301)	(389)	(7,017)	(10,859)
Extensions and discoveries	5,495	3,475	29,387	13,867
Sales of minerals in place	(13)	—	(181)	(43)
Production	(1,440)	(238)	(3,015)	(2,181)
Balance at December 31, 2015	<u>24,131</u>	<u>6,556</u>	<u>75,027</u>	<u>43,190</u>

	Total			
	Oil	NGL	Gas	Oil
	(MBbl)	(MBbl)	(MMcf)	Equivalents
	(In thousands)			
Proved Developed Reserves:				
December 31, 2013	6,846	1,464	31,572	13,572
December 31, 2014	10,162	2,006	34,677	17,948
December 31, 2015	10,022	1,956	31,298	17,194
Proved Undeveloped Reserves:				
December 31, 2013	14,068	572	16,537	17,397
December 31, 2014	19,228	1,702	21,176	24,459
December 31, 2015	14,109	4,599	43,729	25,996

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, 2013, 2014 and 2015

The following information has been prepared in accordance with SEC rules and accounting standards based on the 12-month first-day-of-the-month unweighted average prices in accordance with provisions of the FASB'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 2015, the standardized measure could vary significantly from year to year based on the market conditions that occurred during a given year.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. All reports by DeGolyer and MacNaughton were developed utilizing studies performed by DeGolyer and MacNaughton and assisted by the Engineering and Operations departments of Abraxas. Reserves are estimated by independent petroleum engineers. The report of DeGolyer and MacNaughton dated February 4, 2016, 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, 2013, 2014 and 2015 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 37 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.

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, 2013, 2014 and 2015:

	Years Ended December 31,		
	2013	2014	2015
		(In thousands)	
Future cash inflows	\$2,244,846	\$2,988,464	\$1,241,334
Future production costs	(754,722)	(921,977)	(438,784)
Future development costs	(467,206)	(557,782)	(338,316)
Future income tax expense	(244,394)	(373,095)	—
Future net cash flows	778,524	1,135,610	464,234
Discount	(437,539)	(623,053)	(266,983)
Standardized Measure of discounted future net cash relating to proved reserves	<u>\$ 340,985</u>	<u>\$ 512,557</u>	<u>\$ 197,251</u>

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,		
	2013	2014	2015
		(In thousands)	
Standardized Measure, beginning of year	\$ 278,145	\$340,985	\$ 512,557
Sales and transfers of oil and gas produced, net of production costs	(60,403)	(96,364)	(37,249)
Net change in prices and development and production costs from prior year	169,969	150,504	(488,160)
Extensions, discoveries, and improved recovery, less related costs	156,456	147,275	63,341
Sales of minerals in place	(125,533)	(15,042)	(197)
Revisions of previous quantity estimates	2,930	74,390	(49,602)
Change in timing and other	(62,861)	(82,653)	20,419
Change in future income tax expense	(45,532)	(40,636)	124,886
Accretion of discount	27,814	34,098	51,256
Standardized Measure, end of year	<u>\$ 340,985</u>	<u>\$512,557</u>	<u>\$ 197,251</u>

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,		
	2013	2014	2015
Oil (per Bbl) ⁽¹⁾	\$97.33	\$95.28	\$50.12
Gas (per MMBtu) ⁽²⁾	\$ 3.67	\$ 4.35	\$ 2.63
Oil (per Bbl) ⁽³⁾	\$95.90	\$87.11	\$41.25
Gas (per MMBtu) ⁽⁴⁾	\$ 3.65	\$ 5.15	\$ 2.36
NGL's (per Bbl) ⁽⁵⁾	\$31.98	\$37.91	\$10.52

- (1) The quoted oil price for the year ended December 31 of each year, 2013, 2014 and 2015 is the 12-month unweighted average first-day-of-the-month West Texas Intermediate spot price for each month of 2013, 2014 and 2015.
- (2) The quoted gas price for the year ended December 31, 2013, 2014 and 2015 is the 12-month unweighted average first-day-of-the-month Henry Hub spot price for each month of 2013, 2014 and 2015.
- (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

- 21.1 Subsidiaries of Abraxas Petroleum Corporation (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

Corporate Office

18803 Meisner Drive
San Antonio, Texas 78258
Phone: 210.490.4788

Legal Counsel

Winstead PC
San Antonio, Texas

Independent Public Accountants

BDO USA, LLP
San Antonio, Texas

Independent Reservoir Engineers

DeGolyer and MacNaughton
Dallas, Texas

Stock Exchange Listing

The NASDAQ Stock Market
Ticker Symbol: AXAS

Transfer Agent

American Stock Transfer & Trust Company
6201 15th Avenue
Brooklyn, New York 11219
Phone: 800.937.5449

Annual Stockholders Meeting

May 10, 2016 at 9:00 a.m. CT
Abraxas Petroleum Corporation
San Antonio, Texas

OFFICERS

Robert L.G. Watson

President / Chief Executive Officer

Geoffrey R. King, CFA

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

Franklin A. Burke (Director Emeritus)

President, Venture Securities Corporation;
President / Chief Executive Officer,
Burke, Lawton, Brewer & Burke
Ambler, Pennsylvania

Harold D. Carter²

President / Chief Operating Officer (retired),
Sabine Corporation
Dallas, Texas

Ralph F. Cox^{2,3}

President, Rabar Enterprises
Fort Worth, Texas

W. Dean Karrash¹

President / Chief Financial Officer,
Burke, Lawton, Brewer & Burke, LLC
Ambler, Pennsylvania

Jerry J. Langdon¹

Private Investor
Houston, TX

Dennis E. Logue^{2,3}

Chairman of the Board,
Ledyard Financial Group
Hanover, New Hampshire

Brian L. Melton¹

Vice President — Pipeline Mkting. & Business Development
BlueKnight Energy Partners, L.P.
Oklahoma City, Oklahoma

Paul A. Powell, Jr.^{1,3}

Vice President / Director,
Mechanical Development Co.
Roanoke, Virginia

Edward P. Russell

Managing Director,
Tortoise Capital Advisors
Leawood, Kansas

¹ Audit Committee

² Compensation Committee

³ Nominating & Governance Committee

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