2018 Annual Report

Proxy Statement

Form 10-K

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

April 3, 2019

Dear Shareholders,

The past year, 2018, was to say the least a roller coaster for the Oil & Gas industry. At the time of my last shareholders letter in April 2018, our industry was full of optimism supported by ever increasing oil prices. With WTI oil hitting approximately $75 per barrel this past October, the bottom fell out for various reasons and traded in the low $40's by December. Free cash flow rather than growth became the new mantra from Wall St. We struggled with commodity takeaway capacity in both of our basins, Bakken and Delaware, and the price differentials this condition caused. We learned the impact on production guidance from production shut ins due to offset well frac protection can be substantial, and thus realized that changes had to be made.

We are fortunate that we are very flexible when it comes to wells being drilled and completed and thus the amount of capital being spent. We are the operator of over 96% of our proved reserves which gives us complete control as to the operation of our properties. We announced an initial 2019 Capital Expenditure Budget of a scaled down $108 million in early November. This was further reduced to $95 million by the end of December. This drilling and completion budget will allow us to generate free cash flow as well as keep growing production in a double-digit percentage. We remain flexible to increase or decrease this budget further depending on commodity prices. As of the date of this letter, WTI oil is trading back near $60 per barrel.

In North Dakota, after successfully drilling the four well Lillibridge NW Pad in record time, we shut down our Company owned Raven Drilling Rig #1 for budget reasons. This pause also gives us time to deal with gas flaring issues and reduced operations during the winter season which, for North Dakota, became one of the harshest in recent memory. The four wells on the Lillibridge NW Pad are scheduled for frac completion in late spring and at the same time, plans are to start up Raven #1 on the six well Jore Extension Pad.

Even though we grew average daily production (sales) to over 9,800 barrels of oil equivalent, a 33% increase over 2017, we were disappointed that we didn't grow volumes even more due to frac protect well shut ins. Our guidance going forward includes our best estimate of production shut ins for anticipated frac protection. We were also hampered by excessive gas flaring (which is production but is not counted as sales) especially in North Dakota due to processing capacity constraints. The drilling slow down has given us time to work on solutions. I am pleased to report significant progress is being made as I write this letter with even more expected later in 2019. Nonetheless, we have a gas flaring factor in our future production guidance.

Now it sounds like 2018 was a bad year, but it was actually a great year for Abraxas, just punctuated by a few disappointments mentioned above. We generated record revenues of approximately $150 million. We generated record earnings of about $58 million and record EBITDA of $84 million. We spent approximately $170 million, of which roughly $40 million was spent on acreage acquisitions in what we believe is the most prolific portion of the Delaware Basin as evidenced by well results generated by Abraxas and offset operators. We now own over 11,000 net acres, all of which is Held by Production (HBP), which complements our plan of capital flexibility.

Of the $170 million, approximately $130 million was spent on drilling and/or completion or just drilling (to be completed this year) 28 gross operated wells and 13 gross non-operated wells in the Bakken and Delaware with excellent results. The vast majority of our wells are trending above our published type curves for the formations in which the wells are completed. Our scaled back budget for 2019 includes drilling and/or completing or just drilling to be completed in 2020, 17 gross operated wells and completion of 2 gross non-operated wells. With similar results, we expect a great 2019 as well.

There is no question that the E&P business and especially the small-cap E&P universe has fallen out of favor on Wall St. with significant stock price declines for all. Last year it became apparent to me that our Bakken asset alone could be worth more than our market cap, which would imply that the market is not ascribing value to our valuable Delaware basin assets. I announced last fall that my number one priority for the foreseeable future was to find a way to crystalize this value in our share price. This could be an outright sale or some other monetization, or it might be that the best value for shareholders would be to keep the asset and harvest the free cash flow to spend in the Delaware. We recently announced that we have hired Petrie Partners to assist in this endeavor. A sales process is underway and if the appropriate value is achieved, we would sell the Bakken, significantly reduce or retire our debt, and focus our efforts on our Delaware operation with a focus on achieving free cash flow status, and ideally use any remaining cash to buy back shares. I would love to create a bid for our shares where there currently is none.

Excitement ahead. Keep the faith. Thank you for your continued support. You have over one hundred Abraxas employees that are dedicated to this achievement.

Yours Very Truly,

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

April 3, 2019

Dear Stockholders:

You are invited to attend the 2019 Annual Meeting of Stockholders of Abraxas Petroleum Corporation to be held on May 7, 2019, 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 Sodali LLC toll free at (800) 662-5200.

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 7, 2019

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 7, 2019, at 9:00 a.m., local time, for the following purposes:

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

- Harold D. Carter
- Jerry J. Langdon
- Brian L. Melton
- Angela A. Meyer

(2) To ratify the appointment of BDO USA, LLP as Abraxas' independent registered public accounting firm for the year ended December 31, 2019; and

(3) To approve, on an advisory basis, the compensation of the Company's named executive officers.

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

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

The Board of Directors has fixed the close of business on March 20, 2019 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 20, 2019 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 ten 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 Sodali LLC, toll free at (800) 662-5200.

By Order of the Board of Directors,

Stephen T. Wendel
SECRETARY

San Antonio, Texas
April 3, 2019

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of Stockholders to be held May 7, 2019:

This proxy statement and our 2018 Annual Report on Form 10-K are available at www.proxydocs.com/AXAS, 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
SODALI

470 West Avenue
Stamford, Connecticut 06902
(203) 658-9400 (Call Collect)
or
Call Toll-Free (800) 662-5200

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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 2019 Annual Meeting of Stockholders to be held at 9:00 a.m., local time, on May 7, 2019, at Abraxas Petroleum Corporation's corporate office 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 3, 2019. 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' corporate office, 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 20, 2019 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 167,136,398 shares of Abraxas common stock outstanding, which were held by approximately 905 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 Proposals One and Three. 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 is as follows:

Election of Directors. Each share of our Common Stock is entitled to one vote with respect to the election of directors. Each director will be elected by a majority of the votes cast with respect to such director. A "majority of the votes cast" means that the number of votes cast "for" a director exceeds the number of votes cast "against" that director. Abstentions and "broker non-votes" are not considered to be votes cast with respect to the election of directors. Under Nevada law, if the director is not elected at the Annual Meeting, the director will continue to serve on the Board as a "holdover director." As required by the Company's Amended and Restated Bylaws, each director has submitted an irrevocable letter of resignation as a director that becomes effective if he or she is not elected by the stockholders and the Board accepts the resignation. If a director is not elected, the Nominating and Corporate Governance Committee will consider the director's resignation and recommend to the Board whether to accept or reject the resignation. The Nominating and Corporate Governance Committee in making its recommendation and the Board of Directors in making its decision regarding the tendered resignation may each consider any factors or other information that they consider appropriate. The Board of Directors will consider and act on the Nominating and Corporate Governance Committee's recommendation and publicly disclose its determination.

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 of the shares of Common Stock present at the Annual Meeting in person or represented by proxy and entitled to vote on the matter will be considered to determine the outcome of this proposal. Abstentions from voting will have the same effect as a vote against this proposal. 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, 2019.

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 of the shares of Common Stock present at the Annual Meeting in person or represented by proxy and entitled to vote on the matter will be considered to determine the outcome of this proposal. Abstentions from voting will have the same effect as a vote against this proposal, and broker non-votes will have no effect on the outcome of this proposal. Brokers, as nominees for the beneficial owner, may not exercise discretion in voting on this matter and may only vote on this proposal as instructed by the beneficial owner of the shares. The outcome of this proposal is advisory in nature and is non-binding.

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 6, 2019.

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" proposals Two and Three. 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 Sodali LLC to assist in the solicitation of proxies at a fee estimated not to exceed $8,000. In addition, we have agreed to reimburse Morrow Sodali 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 materials 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 2019 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.proxydocs.com/AXAS*.

Notice Only Option

Under the notice only option, which we have elected **NOT** to use for the 2019 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 2019 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, or SEC, 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. We have adopted this "householding" procedure.

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.

Upon receipt of your request, we will promptly deliver a separate set of proxy materials to you. You may also contact Investor Relations as described above if you are receiving multiple copies of our proxy materials and would like to receive only one copy in the future.

PROPOSAL ONE

ELECTION OF DIRECTORS

Abraxas' Articles of Incorporation divide the Board of Directors into three classes of directors serving staggered three-year terms, with one class to be elected at each Annual Meeting. At this year's meeting, four Class III directors are to be elected for a term of three years to hold office until the expiration of their term in 2022, or until a successor has been elected and duly qualified. The nominees for Class III director are Harold D. Carter, Jerry J. Langdon, Brian L. Melton and Angela A. Meyer. 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, each director will be elected by a majority of the votes cast with respect to such director. A "majority of the votes cast" means that the number of votes cast "for" a director exceeds the number of votes cast "against" that director. Abstentions and "broker non-votes" are not considered to be votes cast with respect to the election of directors. Under Nevada law, if the director is not elected at the Annual Meeting, the director will continue to serve on the Board as a "holdover director." As required by the Company's Amended and Restated Bylaws, each director has submitted an irrevocable letter of resignation as a director that becomes effective if he or she is not elected by the stockholders and the Board accepts the resignation. If a director is not elected, the Nominating and Corporate Governance Committee will consider the director's resignation and recommend to the Board whether to accept or reject the resignation. The Nominating and Corporate Governance Committee in making its recommendation and the Board of Directors in making its decision regarding the tendered resignation may each consider any factors or other information that they consider appropriate. The Board of Directors will consider and act on the Nominating and Corporate Governance Committee's recommendation and publicly disclose its determination..

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 2021, the term of the Class II directors expires in 2020 and the term of the Class III directors expires in 2022.

Name and Municipality of Residence	Age	Office	Class
Robert L.G. Watson San Antonio, Texas	68	Chairman of the Board, President and Chief Executive Officer	II
Harold D. Carter Dallas, Texas	80	Director	III
Ralph F. Cox Fort Worth, Texas	86	Director	II
W. Dean Karrash North Wales, Pennsylvania	57	Director	I
Jerry J. Langdon Houston, Texas	67	Director	III
Dennis E. Logue Enfield, New Hampshire	75	Director	II
Brian L. Melton Oklahoma City, Oklahoma	49	Director	III
Angela A. Meyer Los Altos, California	57	Director	III
Paul A. Powell, Jr. Roanoke, Virginia	73	Director	I
Edward P. Russell Stilwell, Kansas	55	Director	I

Director Nominees

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

Harold D. Carter, a director of Abraxas since October 2003, has over 50 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 served as a director of Brigham Resources, LLC from 2013 to 2017 and has served as a director of Brigham Minerals, LLC since 2013. 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 valuable to us because Brigham Exploration's principal area of activity was the Williston Basin, where it targeted the Bakken, Three Forks and Red River formations. Brigham Exploration was acquired in 2011 by Statoil ASA for approximately $4.4 billion. Additionally, we believe that Mr. Carter's tenure as a director of Brigham Resources is particularly valuable to us because Brigham Resources' principal area of activity was the Delaware Basin, where it targeted the Wolfcamp formation. Brigham Resources was acquired in 2017 by Diamondback for approximately $2.6 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 in Communications from the University of Texas.

We believe that 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. Mr. Melton has served as the Chief Commercial Officer for Blueknight Energy Partners (Nasdaq: "BKEP", or "Blueknight"), a publicly traded master limited partnership (MLP) that specializes in providing crude oil and asphalt terminaling, pipeline and transportation services across the U.S., since December 2016, while previously serving as Vice-President of Pipeline Marketing & Business Development for Blueknight from December 2013 until December 2016. 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 that his financial experience is beneficial to our audit committee.

Angela A. Meyer has served as President and CEO of Product Liability Advisors Council, a specialized legal association of more than 80 multinational corporations and 350 outside defense counsel since June 2018. From 2002 through May 2018, Dr. Meyer served as Vice President, Client Services of Exponent, Inc. (NASDAQ: "EXPO", or "Exponent"), a science and engineering consulting firm, where she was the chief business development, marketing and client relations officer and served on the firm's operating and development committees. From 1998 to 2002, Dr. Meyer served as Marketing Manager for Exponent. Dr. Meyer also serves on the External Advisory Board of Summit Consulting, LLC (August 2018-present) and the Advisory Board of SMU Lyle School of Engineering (2006 – present). Dr. Meyer received a BSE, Mechanical Engineering, a MSME, Mechanical Engineering, and a PhD, Mechanical Engineering, from Southern Methodist University.

We believe that Dr. Meyer's business experience will bring new insight to our Board.

Directors with Terms Expiring in 2020 and 2021

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 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 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 and Certified Financial Planner, 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 and Chief Financial Officer 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 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, JWM Partners, Emory Partners and Burnett Partners. Mr. Powell is also manager of WMP Properties LLC and Westpoint LLC, which is the general partner of Westpoint LP. Mr. Powell served on the board of trustees of Emory & Henry College for 16 years (ending in 2016) and currently serves 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 formerly served on the board of Arc Logistics GP LLC, which was 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.

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 Securities Exchange Act of 1934, as amended, or 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 the oil and gas industry, the financial / banking community or with publicly-traded companies. 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, the financial/banking community and/or with publicly-traded companies, together with their past and current board positions.

Meeting Attendance

During the fiscal year ended December 31, 2018, 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 2018, 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' 2018 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 2018, 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 40, more fully describes the activities and responsibilities of the Audit Committee. Geoffrey King, the Company's Chief Financial Officer prior to June 26, 2018, Mr. Harris, Mr. Krog 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 met 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 17, 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 May 2017, the Compensation Committee engaged Longnecker and Associates, which we refer to as "L&A" or the "Compensation Consultant", as its independent compensation consultant. The Committee did not engage any outside compensation consultants in 2018. For more information on the Compensation Committee's processes and procedures, please see "Executive Compensation – Compensation Discussion & 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. The Board of Directors has also determined that Dr. Meyer would be independent if she is elected to the Board. 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 Abraxas with an efficient and effective leadership model. 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 2018. No member of the Compensation Committee was at any time during 2018, 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 Party 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 2018.

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 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. During 2017, the Nominating and Corporate Governance Committee determined that should a position become available on the board of directors, the Committee would actively search for a qualified candidate that would add diversity to the Board on the basis of gender, race, sexual orientation, gender identity, age, disability unrelated to job requirements or other protected status. In 2019, the Nominating and Corporate Governance Committee identified Dr. Meyer and determined to increase the size of the Board by one member and nominate Dr. Meyer for election as a director.

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 of, and provide all of the information required by, Abraxas' Amended and Restated Bylaws. These provisions and required information are summarized under "Stockholder Proposals for 2020 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.

Non-Management Sessions

The Board generally schedules regular executive sessions involving exclusively non-management directors generally at the time of each in-person board meeting. Our Lead Independent Director, Mr. Cox, presides at all such executive sessions.

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 20, 2019, the number and percentage of outstanding shares of common stock of Abraxas indicated in the following table. Abraxas' Board has adopted stock ownership guidelines. Except as otherwise noted below, the address for each of the beneficial owners is c/o Abraxas Petroleum Corporation, 18803 Meisner Drive, San Antonio, Texas 78258. Please read "Executive Compensation – Stock Ownership Guidelines." None of the shares listed below have been pledged as security.

Name of Beneficial Owner	Number of Shares[(1)]	Percentage (%)
Robert L.G. Watson	2,901,469[(2)]	1.7%
Steven P. Harris	50,000[(3)]	*
Peter A. Bommer	859,373[(4)]	*
Tod A. Clarke	295,441[(5)]	*
Kenneth W. Johnson	596,099[(6)]	*
G. William Krog, Jr.	473,312[(7)]	*
Dirk A. Schwartz	223,543[(8)]	*
Stephen T. Wendel	1,012,770[(9)]	*
Harold D. Carter	403,614[(10)]	*
Ralph F. Cox	673,985[(11)]	*
W. Dean Karrash	691,909[(12)]	*
Jerry J. Langdon	132,648[(13)]	*
Dennis E. Logue	345,313[(14)]	*
Brian L. Melton	265,781[(15)]	*
Paul A. Powell, Jr.	355,776[(16)]	*
Edward P. Russell	251,800[(17)]	*
BlackRock, Inc.	11,786,282[(18)]	7.1%
Mangrove Partners Master Fund, Ltd.	9,645,318[(19)]	5.8%
The Vanguard Group Inc.	9,120,285[(20)]	5.5%
All Officers and Directors as a Group (16 persons)	9,532,833	5.7%

* Less than 1%

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

(2) Includes 1,137,000 shares issuable upon exercise of vested options granted pursuant to the LTIP (as defined on page 23), 52,511 restricted shares subject to vesting and 244,603 shares in a retirement account.

(3) Includes 50,000 restricted shares subject to vesting.

(4) Includes 477,775 shares issuable upon exercise of vested options granted pursuant to the LTIP, 28,539 restricted shares subject to vesting and 46,559 shares in a retirement account.

(5) Includes 157,375 shares issuable upon exercise of vested options granted pursuant to the LTIP, 27,397 restricted shares subject to vesting and 37,437 shares in a retirement account.

(6) Includes 216,625 shares issuable upon exercise of vested options granted pursuant to the LTIP, 130,845 restricted shares subject to vesting and 39,926 shares in a retirement account.

(7) Includes 292,225 shares issuable upon exercise of vested options granted pursuant to the LTIP, 23,973 restricted shares subject to vesting and 37,871 shares in a retirement account.

(8) Includes 80,000 shares issuable upon exercise of vested options granted pursuant to the LTIP, 46,147 restricted shares subject to vesting and 24,727 shares in a retirement account.

(9) Includes 496,387 shares issuable upon exercise of vested options granted pursuant to the LTIP, 28,539 restricted shares subject to vesting and 131,423 shares in a retirement account.

(10) Includes 196,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan (as defined on page 35), 7,577 shares in a family trust and 42,598 shares in a retirement account.

(11) Includes 256,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(12) Includes 136,000 shares issuable upon exercise of vested options granted pursuant to the Directors Plan and 522,911 shares managed by BLB&B Advisors, LLC. Mr. Karrash is a Portfolio Manager with BLB&B Advisors, LLC and in such capacity, shares voting and dispositive power over these shares. Mr. Karrash disclaims beneficial ownership of the shares managed by BLB&B Advisors, LLC.

(13) Includes 124,000 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(14) Includes 256,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(15) Includes 231,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(16) Includes 206,500 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 231,500 shares issuable upon exercise of vested options granted pursuant to the Directors Plan.

(18) According to information in its Schedule 13G/A dated February 4, 2019, 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 Financial Management, Inc.,

BlackRock Fund Advisors, BlackRock Institutional Trust Company, N.A. and BlackRock Investment Management, LLC. BlackRock, Inc. has sole dispositive power over 11,786,282 shares and sole voting power over 11,500,644 shares. The address of BlackRock, Inc. is 55 East 52nd Street, New York, NY 10055.

(19) According to information in its Schedule 13G/A dated February 7, 2019, Mangrove Partners Master Fund, Ltd. (the "Master Fund"), Mangrove Partners and Nathaniel August have shared dispositive power over 9,648,318 shares and shared voting power over 9,648,318 shares. The shares are held by the Master Fund. Beneficial ownership is also claimed by Mangrove Partners which serves as the investment manager of the Master Fund and Nathaniel August who is the principal of Mangrove Partners. The address of the Master Fund and Mangrove Partners is c/o Maples Corporate Services, Ltd., PO Box 309, Ugland House, South Church Street, George Town, Grand Cayman, Cayman Islands KY1-1104. The address of Nathaniel August is 645 Madison Avenue, 14th Floor, New York, New York 10022.

(20) According to information in its Schedule 13G/A dated February 11, 2019, The Vanguard Group Inc. is the parent corporation of the following subsidiaries which own shares of our common stock: Vanguard Fiduciary Trust Company and Vanguard Investments Australia, Ltd. The Vanguard Group, Inc. has sole dispositive power over 8,819,149 shares and sole voting power over 312,777 shares. The address of The Vanguard Group Inc. is 100 Vanguard Blvd, Malvern, PA 19355.

Equity Compensation Plan Information

The following table gives aggregate information regarding grants under all of Abraxas' equity compensation plans through December 31, 2018.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by security holders	7,549,448	$ 2.37	2,758,930
Equity compensation plans not approved by security holders	—	—	—

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 2018, 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	68	Chairman of the Board, President and Chief Executive Officer
Steven P. Harris San Antonio, Texas	45	Vice President – Chief Financial Officer
Peter A. Bommer San Antonio, Texas	62	Vice President – Engineering
Tod A. Clarke San Antonio, Texas	59	Vice President – Land
G. William Krog, Jr. San Antonio, Texas	65	Vice President – Chief Accounting Officer
Dirk A. Schwartz San Antonio, Texas	60	Vice President – Business Development
Kenneth W. Johnson San Antonio, Texas	61	Vice President – Operations
Stephen T. Wendel San Antonio, Texas	69	Vice President – Marketing & Contracts and Secretary

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.

Steven P. Harris has served as Vice President – Chief Financial Officer since November 2018. Mr. Harris joined Abraxas in June 2018 as Director, Finance and Capital Markets. Prior to joining Abraxas, from June 2017 to May 2018 Mr. Harris was with Sundance Energy where he assisted Sundance's Business Development and Investor Relations efforts. From 2008 through 2017, Mr. Harris was a Managing Director and headed the U.S. Energy Investment Banking division of Canaccord Genuity in Houston, Texas. Prior to joining Canaccord Genuity, Mr. Harris served in the Business Development Group at El Paso Exploration and Production. Mr. Harris earned his Bachelor of Business Administration from the University of Texas at Austin and a Master of Business Administration from the Rice University Jesse H. Jones Graduate School of Management.

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.

Tod A. Clarke has served as Vice President – Land since August 2017. Mr. Clarke joined Abraxas in 2000 as Land Manager. Prior to joining Abraxas, Mr. Clarke worked at Exxon USA for 15 years. Mr. Clarke received a Bachelor of Science – Land Management degree from the University of Houston in 1984. Mr. Clarke also is a Certified Petroleum Landman.

Kenneth W. Johnson has served as Vice President – Operations since September 2018. Mr. Johnson joined Abraxas in 2000 and most recently served as Regional Operations Manager. Prior to joining Abraxas, Mr. Johnson served as a consultant to various operators in supervisory and operations management roles across the US including the Mid-Continent, Rockies, and Gulf Coast regions.

G. William Krog, Jr. has served as Chief Accounting Officer since 2011 and Vice President – Chief Accounting Officer since November 2017. Mr. Krog joined Abraxas in 1995 and most previously served as Information Systems / Financial Reporting Director prior to being appointed Chief Accounting Officer. 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.

Dirk A. Schwartz has served as Vice President – Business Development since 2017. Mr. Schwartz joined Abraxas in 2013 as Director of Corporate Development. Prior to joining Abraxas, Mr. Schwartz worked at Renegade Petroleum (North

Dakota) Ltd. as manager of US negotiations. Mr. Schwartz received a Bachelor of Science in Geology degree from the University of Wyoming in 1982 and a Master of Science in Geology degree from the University of North Dakota in 1987. Mr. Schwartz also is a Certified Petroleum Landman.

Stephen T. Wendel has served as Vice President – Marketing & Contracts since August 2017 and as Corporate Secretary since 1988. Mr. Wendel served as Abraxas' Vice President of Land and Marketing from 1990 to August 2017. 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.

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 2018 was a group of exploration and production companies originally provided by Longnecker & Associates, or L&A or the Compensation Consultant, in 2014 and subsequently updated by the Compensation Committee due to bankruptcies and other corporate events.

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. During 2017, 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 2017, 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 among the companies in our peer group;
- Assisted with the analysis and selection of peer group companies for compensation purposes and for comparative total shareholder return, or TSR, purposes;
- Assessed the Company's Annual Bonus Plan (as defined on page 19) metrics versus the companies in our peer group; and
- Assessed the Company's LTIP metrics versus the companies in our peer group.

The Committee did not utilize the services of the Compensation Consultant in 2018.

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 peer group, within Abraxas' budgetary constraints and commensurate with Abraxas' salary structure;

- rewarding outstanding performance; and
- 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 (the "Annual 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.

The advisory vote on executive compensation received the majority of the votes FOR the proposal in May 2018. The Company considered the results of last year's shareholder advisory vote and, given the affirmative vote, did not use this as consideration to change executive compensation decisions and policies.

CEO Pay Ratio

We believe executive pay must be internally consistent and equitable to motivate our employees to create shareholder value. We are committed to internal pay equity, and the Compensation Committee monitors the relationship between the pay our executive officers receive and the pay our non-managerial employees receive. The Compensation Committee reviewed a comparison of CEO pay (base salary and incentive pay) to the pay of all our employees in 2018. The compensation for our CEO in 2018 was approximately 8.7 times the median pay of our full-time employees.

Our CEO to median employee pay ratio is calculated in accordance with SEC regulations. We identified the median employee by examining the 2018 total cash compensation for all individuals, excluding our CEO, who were employed by us on December 16, 2018, the last day of our payroll year. We included all employees, whether employed on a full-time, part-time, or seasonal basis. We did not make any assumptions, adjustments, or estimates with respect to total cash compensation and we did not annualize the compensation for any full-time employees that were not employed by us for all of 2018. We believe the use of total cash compensation for all employees is a consistently applied compensation measure because we do not widely distribute annual equity awards to employees. Approximately 30% of our employees receive annual equity awards.

After identifying the median employee based on total cash compensation, we calculated annual total compensation for such employee using the same methodology we use for our named executive officers as set forth in the 2018 Summary Compensation Table later in this proxy statement.

As illustrated in the table below, our 2018 CEO to median employee pay ratio was 8.7:1.

	CEO to Median Employee Pay Ratio	
	President and CEO	**Median Employee**
Base Salary	$505,000	$75,928
Non-Equity Incentive Plan Compensation	210,174	—
Discretionary Bonus	10,000[1]	7,551[2]
All Other Compensation	12,625[3]	1,720[4]
	$737,799	$85,199

(1) This amount reflects a discretionary holiday bonus of $10,000, awarded to Mr. Watson in 2018.
(2) This amount reflects a $6,449 safety bonus, and $1,102 holiday bonus to the median employee.
(3) This amount represents a $9,625 contribution by Abraxas to Mr. Watson's 401(k) plan and a $3,000 contribution to Mr. Watson's health savings accounts for 2018.
(4) This amount represents a $1,720 contribution to the median employee health savings account.

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 2016, 2017 and 2018 we utilized a list of peer companies originally provided by L&A in 2014 and subsequently updated by the Committee due to bankruptcies and other corporate events to analyze our salary structure. L&A originally identified, and the Committee updated, 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 geographic areas. L&A then analyzed (and the Committee updated) each company based on:

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

Using these criteria, in 2018 the following were the comparable companies: Approach Resources, Inc. (AREX), Contango Oil & Gas Company (MCF), Earthstone Energy, Inc. (ESTE), Halcon Resources Corporation (HK), Lilis Energy, Inc. (LLEX), Ring Energy, Inc. (REI) and Rosehill Resources Inc. (ROSE). Halcon Resources Corporation (HK) and Lilis Energy, Inc. (LLEX) were added to the list in 2018 based upon the criteria originally utilized by L&A. Gastar Exploration Inc. (GST) and Lonestar Resources US Inc. (LONE) were removed from the list as they were no longer comparable companies due to market capitalization or lack of operational similarities.

Abraxas' salary range is set by reference to the salaries paid by the comparable companies considering the responsibilities and expectations of each executive officer while remaining within Abraxas' budgetary constraints. We utilize salary information from the comparable companies 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 companies. We believe that the base salary levels for our executive officers are consistent with the practices of the comparable companies, 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 2018 are set forth below in the Summary Compensation Table. For 2018, base salaries, paid as cash compensation, were $1,585,027 with Mr. Watson receiving $505,000. We believe that the base salaries paid achieved our objectives.

Annual Bonuses. Abraxas' Annual Bonus Plan was initially adopted by our Board of Directors in 2003. In May 2017, in connection with the Company's annual compensation cycle, the Compensation Committee asked L&A to conduct a thorough review of the Company's grant practices under the Annual Bonus Plan. Under the terms of the Annual Bonus Plan as approved by Abraxas's stockholders at the annual meeting in 2014, the performance measures include:

- increases in, or levels of, net asset value (after taking the risking of reserves into account);
- net asset value per share;
- pretax earnings;

- earnings before interest and taxes;
- earnings before interest, taxes, depreciation and amortization;
- net income and/or earnings per share;
- return on equity, return on assets or net assets, return on capital (including return on total capital or return on invested capital);
- share price or stockholder return performance (including, but not limited to, growth measures and total stockholder return, which may be measured in absolute terms and/or in comparison to a group of peer companies or an index);
- oil and gas reserve replacement, reserve growth and finding and development cost targets;
- oil and gas production targets;
- performance of investments in oil and gas properties;
- cash flow measures (including, but not limited to, cash flows from operating activities, discretionary cash flows, and cash flow return on investment, assets, equity, or capital); and
- levels of operating and/or non-operating expenses.

On August 8, 2017, the Board of Directors, at the recommendation of the Compensation Committee, adjusted the eligibility, metrics and payouts associated with the Annual Bonus Plan. The adjustments became effective on January 1, 2018. Employees earning above $180,000, including all NEOs, were eligible for participation in the Annual Bonus Plan. Employees earning below $180,000 were eligible for participation at the discretion of the Compensation Committee. The target payout ranged from 50-70% of the eligible employee's base salary depending upon the employee's role and responsibilities. The target payout was multiplied by a target multiplier based on Company performance versus a given set of performance measures established by the Compensation Committee. For 2018, the Compensation Committee utilized seven key performance metrics: (i) oil and gas production versus guidance publicly disclosed to the investment community measured in barrels of equivalent production per day ("Boepd"), (ii) lease operating expenses ("LOE") per barrel of oil equivalent produced ("LOE/Boe"), (iii) general and administrative expense before non-equity incentive bonus accruals ("Cash G&A"), (iv) Net Asset Value per share ("NAV/share"), (v) ratio of debt to earnings before interest, taxes, depreciation and amortization as calculated under our revolving credit facility ("Debt/Bank EBITDA"), (vi) proved developed producing finding and development costs ("PDP F&D") and (vii) a subjective determination of individual performance determined by the Compensation Committee. The Compensation Committee believes that the officers and employees can exert some measure of control over these metrics and that these metrics best measure the short-term operational and financial success of the Company. The table below indicates the relative weighting of specific metrics as well as the specific metric targets for the Annual Bonus Plan in 2018:

Metric	Weighting	Threshold	Target	Maximum
Production (Boepd)	20%	10,000	11,000	12,000
LOE/Boe ($/Boe)	5%	$ 6.00	$ 5.00	$ 4.00
Cash G&A ($ millions)	5%	$ 9.5	$ 9.0	$ 8.5
NAV/share ($/share)	20%	$ 1.49	$ 1.86	$ 2.11
Debt/Bank EBITDA	20%	1.45x	1.00x	0.80x
PDP F&D ($/Boe)	10%	$ 15.00	$ 12.50	$ 10.00
Individual Performance	20%	Determined by Committee		

The table below sets forth the 2018 Results under the Annual Bonus Plan:

Metric	2018 Amount	Result	Multiplier (A)	Weighting (B)	Payout Multiplier (A x B)
Production (Boepd)	9,809	Below threshold	0	20%	0
LOE/Boe ($/Boe)	$ 6.73	Below threshold	0	5%	0
Cash G&A ($ millions)	$ 8.5	Maximum	2	5%	10%
NAV/share ($/share)	$ 0.95	Below threshold	0	20%	0
Debt/Bank EBITDA	2.11:1	Below threshold	0	20%	0
PDP F&D ($/Boe)	$ 13.63	Above threshold	7.74	10%	7.74%
Individual performance	Determined by Committee			20%	10% – 40%

Bonuses earned under the 2018 metrics and results were as follows:

Name	Base Salary	Bonus Award Achieved (Percentage of Salary)	Maximum Award (Percentage of Salary)	Annual Bonus Earned Under the Annual Bonus Plan	Annual Bonus Paid Under the Annual Bonus Plan
Robert L.G. Watson	$520,000	40%	70%	$210,174	$210,174
Steven P. Harris	250,000	19%	70%	48,545	48,545
Peter A. Bommer	275,000	26%	70%	72,650	72,650
Kenneth W. Johnson	275,000	40%	70%	111,150	111,150
Stephen T. Wendel	275,000	26%	70%	72,650	72,650

Production: Abraxas's 2018 production guidance was 10,000 -12,000 barrels of oil equivalent per day ("Boepd"). This guidance was based on management's estimate of production volumes for the year, which the Compensation Committee felt was a good measurement of operational performance. The low end of the guidance range of 10,000 Boepd represented the threshold level of performance. The high end of the guidance range of 12,000 Boepd represented the maximum level of performance. The mid-point of the guidance range of 11,000 Boepd represented the target level of performance.

LOE/Boe: Abraxas's 2018 LOE/Boe guidance was $4.00 to $6.00. This guidance was based on management's estimate of total lease operating expenses divided by total net barrels of equivalent production for the year ended December 31, 2018. The Compensation Committee chose this metric as it believed it was a good measurement of operational performance. The high end of the guidance range of $6.00/Boe represented the threshold level of performance. The low end of the guidance range of $4.00/Boe represented the maximum level of performance. The mid-point of the guidance range of $5.00/Boe represented the target level of performance.

Cash G&A: Abraxas's 2018 Cash G&A guidance of $8.5 to $9.5 million. This guidance was based on management's estimate of total Cash G&A for the year ended December 31, 2017 with assumed G&A inflation of 12%. For purposes of this calculation Cash G&A was calculated before any non-equity incentive bonus accruals. The Compensation Committee chose this metric based upon its belief that this metric was a good measurement of administrative cost control, which ultimately works to the benefit of stockholders. $9.0 million represented forecasted cash G&A for 2018 without bonus accruals and with assumed G&A inflation of 12%. The high end of the guidance range of $9.5 million represented the threshold level of performance. The low end of the guidance range of $8.5 million represented the maximum level of performance.

The table below shows the calculation of Cash G&A for 2018 and a reconciliation of Cash G&A to general and administrative expenses (in thousands):

G&A from December 31, 2018 Statement of Operations	$12,041
Less:	
Stock-based compensation	(2,366)
Non-equity incentive plan accrual	(1,082)
Cash G&A	$ 8,593

NAV/share: NAV/share was calculated using the equation outlined below:

Net Asset Value Calculation	
+	PV-10 Proved Developed Producing Reserves
+	PV-20 Proved Developed Non-Producing Reserves
+	PV-20 Proved Undeveloped Reserves
+	PV-30 Probable Reserves
+	Property & Equipment
+	Other Assets
±	Net Working Capital
−	Debt
=	Net Asset Value ("NAV")
÷	Shares Outstanding
=	NAV per share

For the year ended December 31, 2018, the independent petroleum engineering firm of LaRoche Petroleum Consultants estimated reserves for approximately 99% 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 LaRoche Petroleum Consultants to prepare reserve estimates for those properties as they are located in a widely dispersed geographic area and have relatively low value. LaRoche Petroleum Consultants also estimates our probable reserves. 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 the standardized measure of discounted future net cash flows to PV-10 at December 31, 2017 and 2018 (in thousands):

	December 31,	
(in thousands)	**2017**	**2018**
Standardized measure of discounted future net cash flows	$405,741	$651,884
Present value of future income taxes discounted at 10%	21,700	37,413
PV-10	$427,441	$689,297

PDP F&D: The denominator for the PDP F&D calculation was calculated using proved developed producing reserves as of December 31, 2018 less proved developed producing reserves as of December 31, 2018, plus production for the year ended December 31, 2018, plus any asset sales for the year ended December 31, 2018 less any asset acquisitions (including leasehold acquisitions) for the year ended December 31, 2018. The numerator for the PDP F&D calculation was total capital expenditures for the year ended December 31, 2018 less any capital expenditures associated with acquisitions (including leasehold acquisitions) for the year ended December 31, 2018. The target level of PDP F&D for the year represents the approximate mid-point of the industry average PDP F&D $15.00/bbl utilized by Seaport Global Securities, Inc. and Abraxas' actual PDP F&D ($13.63/bbl) for the year ended December 31, 2018. The threshold level PDP F&D represented the industry average PDP F&D ($20.00/bbl) as calculated by Seaport Global Securities, Inc. for the year ended December 31, 2018. The maximum level represented the approximate PDP F&D achieved by Abraxas Petroleum for the year ended December 31, 2018.

Debt/Bank EBITDA: For the purposes of this calculation, total debt was calculated as outstanding principal amount of debt, excluding debt associated with the office building and obligations with respect to surety bonds and derivative contracts of the Company as of December 31, 2018. For the purposes of this calculation, Bank EBITDA 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 loss, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. The threshold level of Debt/Bank EBITDA was the Company's December 31, 2018 Debt/Bank EBITDA of 1.45x. The target level of Debt/Bank EBITDA was 1.0x. The maximum level of Debt/Bank EBITDA was 0.8x.

The table below shows the calculation of Debt/Bank EBITDA for 2018 and a reconciliation of Bank EBITDA to Net Income:

(In thousands)	Year End 2018
Net (loss) income	$ 57,821
Net interest expense	7,052
Depreciation, depletion and amortization	42,759
Amortization of deferred financing fees	440
Stock-based compensation	2,366
Unrealized (gain) loss on derivative contracts	(27,098)
Expenses incurred with offerings and execution of loan agreement	304
Other non-cash items	537
Bank EBITDA	$ 84,181
Credit facility borrowings	$180,250
Debt/Bank EBITDA	2.14X

Individual Performance: The Compensation Committee made a subjective determination of individual performance of each eligible employee's accomplishments and performance to determine whether that employee earns the Threshold, Target or Maximum level of performance for this metric.

Generally, the bonus amount for the "threshold" level of performance was 50% of the target and the bonus amount for "maximum" level of performance was 200% of the target. Bonuses can range between these amounts based on the level of performance attained. Generally, no bonus was payable with respect to a defined metric if the "threshold" level of performance was not met on that metric. Performance that would qualify for bonuses at the threshold level was expected in normal operating circumstances. Performance satisfying the criteria for bonuses at the target level was believed to be achievable only with additional effort and results. Performance that would qualify for bonuses at the maximum level was believed to be achievable only with extraordinary efforts and results.

The specific levels of the first three metrics (production, LOE/Boe and Cash G&A) that would trigger the threshold, target and maximum bonus payments was tied to the Company's public guidance with respect to these metrics. The performance criteria for the target bonus was generally at the midpoint of the range of the Company's public guidance, with the threshold and maximum bonuses being payable for performance that was less than or exceeded those expectations. The threshold and maximum values were set within ranges recommended by the Compensation Committee and approved by the Board.

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 to pay bonuses even if no bonus would be payable under the Annual Bonus Plan, and further has the discretion not to pay bonuses even if a bonus was earned under the Annual Bonus Plan. In the past, the Committee has elected to pay a portion of the annual bonus in shares of 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 the Annual Bonus Plan.

Long-Term Equity Incentives

In May 2017, the Compensation Committee retained L&A to conduct a thorough review of the Company's grant practices under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan ("LTIP"). In August 2017, the Board of Directors, at the recommendation of the Compensation Committee, adjusted the eligibility, targeted vesting schedule and award requirements for the LTIP. The adjustments took effect on January 1, 2018.

Employees, including all of the NEOs, earning above $180,000 are eligible to participate in the LTIP. Employees earning below $180,000 are eligible for participation at the discretion of the Compensation Committee. It is anticipated that awards will largely be made up of restricted stock grants. The target award for participants is 50% of the employee's yearly salary, which can be adjusted at the Compensation Committee's discretion. One-half of the target award vests annually over three years. Vesting of the remaining half is based on the achievement of performance goals established by the Compensation Committee.

For 2018, the Compensation Committee established that each NEO would receive 50% of his base salary in restricted stock and performance awards under the LTIP. Half of the performance awards under the LTIP was in restricted shares, which vest annually over three years. The remaining 50% of the award was in performance shares which vest on the third anniversary of the grant date of the award based on the Company's achievement of performance goals. The performance goals for 2018 were based on Relative Total Shareholder Return ("Relative TSR") versus the Company's peer group over a three-year period starting on December 31, 2017. The Compensation Committee believes Relative TSR is the most prevalent performance measure among the companies in Abraxas' peer group.

For purposes of calculating Relative TSR, the Compensation Committee utilized the peer group disclosed on page 19. Relative TSR was calculated using each peer group companies' share price appreciation and dividends paid to show the total return to the stockholder expressed as an annualized percentage. The TSR for each of the peers and Abraxas was ranked from the highest TSR to the lowest TSR. Participants will have the ability to earn a payout of the award versus the target using the following scale:

	Abraxas Relative TSR Performance	
Performance Payout	**Rank**	**Payout vs. Target**
Maximum	1	200%
	2	150%
Target	3	100%
	4	75%
	5	50%
Threshold	6	25%
	7	0%
	8	0%

Should Abraxas' Total Shareholder Return be a negative percentage over the three-year time period, none of the performance shares will vest. Vesting is accelerated in certain events described under "Employment Agreements and Potential Payments Upon Termination or Change in Control." Upon a Termination or Change in Control, the Performance Shares will vest at a maximum 100% targeted payout subject to the shares generating a positive Absolute Total Shareholder Return between the grant date and the effective date of the Termination or Change in Control.

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 subsequently amended by our stockholders, 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 the LTIP 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, 2018, a total of 12,600,000 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 2018 was $18,500 for employees under the age of 50 and $24,500 for employees 50 years of age or older. The Board of Directors has also suggested a cap on the amount (or percentage) of Abraxas common stock that each employee should own in their individual 401(k) account to encourage diversification. The maximum suggested percentage has been set at 20% and each employee is encouraged to reduce 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.

Proxy Statement

2019 Base Salary Decisions and Bonus Metrics

In general, base salaries for 2019 increased 3.0% from 2018 for our named executive officers to adjust for increases in the cost of living and to adjust salaries to levels consistent with our peer group while remaining within Abraxas' budgetary constraints.

The Committee has also established the following metrics under the Annual Bonus Plan for 2019:

Metric	Weighting	Threshold	Target	Maximum
Production (Boepd)	10%	10,500	11,000	11,500
LOE/Boe ($/Boe)	5%	$ 6.00	$ 5.00	$ 4.00
Cash G&A ($ millions)	5%	$ 10.5	$ 9.5	$ 8.5
NAV/share ($/share)	20%	$ 2.41	$ 3.00	$ 3.42
Debt/Bank EBITDA	30%	2.1x	1.5x	1.0x
PDP F&D ($/Boe)	10%	$ 18.95	$ 15.00	$ 13.00
Individual Performance	20%	Determined by Committee		

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 evaluating compensation program alternatives, the Compensation Committee considered the potential impact on the Company of Section 162(m) of the Internal Revenue Code of 1986, as amended. Prior to 2018, Section 162(m) limited to $1 million the amount that a publicly traded corporation, such as the Company, may deduct for compensation paid in any year to its chief executive officer and certain other named executive officers ("covered employees"). At the time the Compensation Committee made its compensation decisions, the tax law provided that compensation which qualified as "performance-based" was excluded from the $1 million per covered employee limit if, among other requirements, the compensation was payable only upon attainment of pre-established, objective performance goals under a plan approved by our stockholders. However, this exception was repealed in the tax reform legislation signed into law on December 22, 2017. As a result, it is uncertain whether compensation that the Compensation Committee intended to structure as performance-based compensation under Section 162(m) will be deductible in the future.

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. If such compensation does not comply with the tax rules applicable to non-qualified deferred compensation arrangements, then the benefits would be taxable in the first year they are not subject to a substantial risk of forfeiture and are subject to certain additional adverse tax consequences.

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, 2018 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 & 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 & Analysis be included in this proxy statement.

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

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

SUMMARY COMPENSATION TABLE

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

Name and Principal Position	Year	Salary ($)[1]	Bonus ($)[2]	Stock Awards ($)[3]	Option Awards ($)[4]	Non-Equity Incentive Plan Compensation ($)[5]	All Other Compensation ($)[6]	Total ($)[7]
Robert L.G. Watson	2018	505,000	10,000	115,000	—	210,174	12,625	852,799
President, Chief Executive Officer and	2017	452,333	313,154	—	—	322,000	12,450	1,099,937
Chairman of the Board	2016	368,000	17,692	—	269,912	322,000	9,275	986,879
Steven P. Harris[8]	2018	135,417	2,804	133,500	—	48,545	1,625	321,891
Vice President—Chief Financial Officer								
Peter A. Bommer	2018	267,750	5,288	62,500	—	72,650	12,625	420,813
Vice President—Engineering	2017	245,833	170,193	—	—	175,000	12,450	603,476
	2016	204,167	9,615	—	96,258	175,000	7,482	492,522
Kenneth R. Johnson[9]	2018	245,833	5,288	246,170	—	111,150	24,625	633,066
Vice President—Operations								
Stephen T. Wendel	2018	268,750	5,288	62,500	—	72,650	12,625	421,813
Vice President—Land & Marketing	2017	239,750	163,577	—	—	175,000	12,450	590,777
	2016	196,000	9,231	—	115,119	168,000	7,183	495,533
Geoffrey R. King[10]	2018	147,000	—	—	—	—	9,625	156,625
Former Vice President—Chief	2017	270,417	187,211	—	—	192,500	9,450	659,578
Financial Officer	2016	224,583	10,577	—	183,866	192,500	8,231	619,757

(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 $10,000, $2,804, $5,288, $5,288 and $5,288 awarded to Messrs. Watson, Harris, Bommer, Johnson and Wendel, respectively, in 2018. The amounts in this column reflect a discretionary holiday bonus of $8,846, $5,288, $4,808 and $4,808 awarded to Messrs. Watson, King, Bommer and Wendel, respectively, in 2017. The amounts in this column also reflect a one-time discretionary bonus of $304,308, $181,923, $165,385, and $158,769 paid to Messrs. Watson, King, Bommer and Wendel, respectively, in 2017. The amounts in this column also reflect a discretionary holiday bonus of $17,692, $10,577, $9,615 and $9,231 awarded to Messrs. Watson, King, Bommer and Wendel, respectively, in 2016.

(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, 2018 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, 2018 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 2016, 2017 and 2018 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 and health savings accounts for 2016, 2017 and 2018 as well as a $12,000 vehicle allowance for Mr. Johnson in 2018.

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

(8) Joined Abraxas in June 2018. Elected Vice President – Chief Financial Officer in November 2018.

(9) Elected Vice President – Operations in September 2018. Previously served as Regional Operations Manager.

(10) Resigned as Vice President – Chief Financial Officer in June 2018.

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 2018.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]			All other Stock Awards; Number of Shares of Stock or Units[3]	All other Option Awards; Number of Securities Underlying Options (#)[4]	Exercise price of Option Awards ($/Sh)	Grant Date Fair Value of stock and option awards[5]
		Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum ($)				
Robert L.G. Watson	01/01/2018	182,000	364,000	728,000							
	04/02/2018							52,511			114,999
	04/02/2018				13,128	52,511	105,022				114,999
Steven P. Harris	01/01/2018	87,500	175,000	350,000							
	06/20/2018								100,000	2.67	267,000
Peter A. Bommer	01/01/2018	96,250	192,500	385,000							
	04/02/2018							28,539			62,500
	04/02/2018				7,135	28,539	57,078				62,500
Kenneth W. Johnson	01/01/2018	96,250	192,500	385,000							
	04/02/2018							27,306			59,800
	04/02/2018				6,827	27,306	54,612				59,800
	11/06/2018							103,539			186,370
Stephen T. Wendel	01/01/2018	96,250	192,500	385,000							
	04/02/2018							28,539			62,500
	04/02/2018				7,135	28,539	57,078				62,500

(1) Reflects awards under the Annual Bonus Plan. Please see the discussion under "Compensation Discussion & Analysis – Elements of Executive Compensation – Annual Bonuses" for more information. Please also refer to column 5 of the Summary Compensation Table.

(2) Represents the potential number of restricted shares for achieving performance goal described in "Compensation Discussion & Analysis – Elements of Executive Compensation – Long-Term Equity Incentives" payable under the LTIP. Amounts reported (a) in the "Threshold" column reflect 25% of the target number of restricted shares awarded to each named executive officer, which is the minimum amount payable for achieving the performance goal under the Annual Bonus Plan, (b) in the "Target" column reflect 100% of the target number of restricted shares awarded to each named executive officer for achieving the performance goal under the Annual Bonus Plan, and (c) in the "Maximum" column reflect 200% of the target number of restricted shares awarded to each named executive officer, which is the maximum amount payable for achieving the performance goal under the Annual Bonus Plan. If less than minimum levels of performance, as described in the "Threshold" column, are attained with respect to the total shareholder return performance metric applicable to the restricted shares subject to the performance goal, then 0% of the target number of restricted shares awarded will be earned. The number of shares actually delivered at the end of the performance period may vary from the target number of restricted shares, based on our achievement of the specific performance measure (TSR).

(3) Represents shares of restricted stock subject to time-based vesting conditions granted under the LTIP.

(4) Represents time-based option awards under the LTIP.

(5) Represents the grant date fair value determined pursuant to FASB ASC Topic 718, based on the closing price of our common stock on the applicable grant date. The closing price of our common stock on April 2, 2018 was $2.19 and $1.80 on November 6, 2018. With respect to the restricted shares, amounts reflect an aggregate probable settlement percentage of 100% for achieving the performance goals described in "Compensation Discussion & Analysis – Elements of Executive Compensation – Long-Term Equity Incentives." The shares of restricted stock were granted on April 2, 2018.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

The following table provides information concerning outstanding equity awards at December 31, 2018 for our named executive officers.

	Option Awards				Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) (Exercisable)	Number of Securities Underlying Unexercised Options (#) (Unexercisable)(1)	Option Exercise Price ($)	Option Expiration Date	Number of Shares of Stock That Have Not Vested (#)(2)	Market Value of Shares of Units of Stock That Have Not Vested ($)(3)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(2)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Robert L.G. Watson	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				
	20,000	—	3.74	03/08/2022				
	42,000	—	2.39	05/14/2023				
	46,000	—	3.15	03/11/2024				
	225,000	75,000	3.16	03/03/2025				
	207,500	207,500	0.97	03/15/2026				
					52,511	57,237	52,511	57,237
Steven P. Harris	—	100,000	2.67	06/20/2028				
					50,000	54,500	50,000	54,500
Peter A. Bommer	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				
	10,500	—	3.74	03/08/2022				
	23,500	—	2.39	05/14/2023				
	25,000	—	3.15	03/11/2024				
	150,000	50,000	3.16	03/03/2025				
	74,000	74,000	0.97	03/15/2026				
					28,539	31,108	28,539	31,108
Kenneth W. Johnson	11,250	—	0.99	03/17/2019				
	31,875	—	1.75	10/05/2019				
	33,000	—	2.09	03/16/2020				
	15,000	—	4.72	03/15/2021				
	9,500	—	3.74	03/08/2022				
	21,500	—	2.39	05/14/2023				
	23,000	—	3.15	03/11/2024				
	25,000	—	3.55	08/09/2021				
	38,500	38,500	0.97	03/15/2026				
					130,845	142,621	27,306	29,763
Stephen T. Wendel	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				
	10,400	—	3.74	03/08/2022				
	22,300	—	2.39	05/14/2023				
	24,000	—	3.15	03/11/2024				
	112,500	37,500	3.16	03/03/2025				
	88,500	88,500	0.97	03/15/2026				
					28,539	31,108	28,539	31,108

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

(2) For awards granted before January 1, 2018, stock awards vest in 25% increments each year for four years on the anniversary of the grant date. Starting January 1, 2018, the vesting schedule for all restricted stock awards changed to 33.3% each year for three years with the remainder vesting upon achievement of performance goals established by the Compensation Committee.

(3) The market value was calculated based on the closing price of Abraxas' common stock on December 31, 2018 of $1.09 per share multiplied by the number of shares of stock that had not vested as of December 31, 2018.

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, 2018.

	OPTION AWARDS		STOCK AWARDS	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting	Value Realized on Vesting ($)
Robert L.G. Watson	—	—	20,000[(1)]	46,200
Geoffrey R. King[(6)]	—	—	100,000[(2)]	231,000
Steven P. Harris	—	—	—	—
Peter A. Bommer	—	—	200,000[(3)]	462,000
Kenneth W. Johnson	—	—	200,000[(4)]	462,000
Stephen T. Wendel	—	—	95,000[(5)]	179,700

(1) These 20,000 stock awards vested on March 11, 2018 and the closing price of Abraxas' common stock on this date was $2.31.
(2) These 100,000 stock awards vested on March 11, 2018 and the closing price of Abraxas' common stock on this date was $2.31.
(3) These 200,000 stock awards vested on March 11, 2018 and the closing price of Abraxas' common stock on this date was $2.31.
(4) These 200,000 stock awards vested on March 11, 2018 and the closing price of Abraxas' common stock on this date was $2.31.
(5) These 95,000 stock awards consisted of 20,000 stock awards vested on March 11, 2018 and the closing price of Abraxas' common stock was $2.31 and 75,000 stock awards vested on November 4, 2018 and the closing price of Abraxas' common stock on this date was $1.78.
(6) Mr. King resigned as Vice President – Chief Financial Officer on June 26, 2018.

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, 2018, we had eight non-employee directors and eight 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, 2018, the market value of Abraxas common stock was $1.09 per share. As an example, Mr. Watson, our chief executive officer, is required to own 2,385,321 shares of Abraxas common stock to meet the stock ownership guidelines at this price. As of December 31, 2018, two directors satisfied the minimum stock ownership guidelines.

Policies Against Hedging and Pledging Stock

Our NEOs and directors are prohibited from engaging in hedging transactions that are designed to hedge or offset a decrease in market value of such person's Common Stock in the Company. We believe that such conduct could cause an NEO or director to no longer have the same objectives as the Company's other stockholders because these types of transactions could reduce the full risks of stock ownership. In addition, our NEOs and directors may not pledge Company securities as collateral for any other loan.

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 who are not subject to an employment agreement. This plan provides severance benefits in the event of a change in control and for certain other changes in conditions of employment. The affected employees would be entitled to receive one month of base salary for each year of service with Abraxas, up to a maximum of 12 months.

The employment agreements for Messrs. Watson, Harris, Bommer, Johnson and Wendel are scheduled to terminate on December 31, 2019, and are automatically extended for an additional year if by December 1 neither Abraxas nor Messrs. Watson, Harris, Bommer, Johnson or Wendel, as the case may be, has given notice to the contrary. In the event of a Change in Control, the term or any renewal thereof continues in effect for 36 months.

The employment agreements contain the following defined terms:

“Cause” means termination upon

(i) the willful and continued failure by the named executive 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 named executive 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 willful engaging by the named executive officer in conduct which is demonstrably and materially injurious to the Company, monetarily or otherwise. The named executive officer shall not be deemed to have been terminated for Cause unless and until the named executive 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 named executive officer and an opportunity for the named executive officer, together with the named executive officer’s counsel, to be heard before the Board), finding that in the good faith opinion of the Board, the named executive officer was guilty of conduct set forth 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 (not including any period prior to the execution of the employment agreement), 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 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 all or substantially all of the Company's assets.

"Disability" means the incapacity of the named executive officer due to physical or mental illness which causes the named executive 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 named executive officer written notice of termination, the named executive officer has not returned to the full-time performance of his duties.

"Good Reason" means, without the named executive 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 from those in effect immediately prior to a Change in Control, other than any such alteration primarily attributable to the fact that the Company may no longer be a public company or may be a subsidiary of another entity,

(ii) a reduction in his current annual base salary as in effect immediately prior to the Change in Control or as the same may be increased from time to time,

(iii) a change in the principal place of his employment, as in effect at the time of a Change in Control, to a location more than fifty (50) miles from such principal place of employment, excluding required travel on the Company's business to an extent substantially consistent with Employee's business travel obligations as of the date of the agreement,

(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 adopted prior to the Change in Control, unless an equitable arrangement (embodied in an ongoing substitute or alternative plan) has been made with respect to such plan in connection with the Change in Control, 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 existed at the time of the Change in Control,

(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 him 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 as in effect at the time of the Change in Control,

(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 named executive officer's consent with respect to himself.

If, following a Change in Control, an officer's employment is terminated by the Company 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 a lump sum payment equal to three times his annual base salary.

If any lump sum payment to an named executive officer would individually or together with any other amounts paid or payable constitute a would constitute a "parachute payment" (as defined in Section 280G(b)(2) of the Internal Revenue Code of 1986, as amended (the "Code")) (the "Parachute Payments") which will be subject to the excise tax imposed under Section 4999 of the Code (the "Excise Tax"), then the total amounts received by the named executive officer from the Company which constitute Parachute Payments shall be reduced to an amount equal, in the aggregate, to one dollar ($1.00) less than three (3) times the named executive officer's base amount (as defined in Section 280G of the Code) so that no portion of the Parachute Payments received by the named executive officer shall be subject to the Excise Tax, if and only if

(i) such reduction in the Parachute Payments produces a better net after-tax position (taking into account any applicable Excise Tax under Section 4999 of the Code and any applicable income tax) than the total payment provided for herein and (ii) there are no other amounts receivable by the named executive officer from the Company which, by their terms, may not be reduced such that no portion of such amounts received by the named executive officer shall be subject to the Excise Tax.

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, 2018, our named executive officers held 1,540,237 unvested options, of which 514,000 were "in-the-money". Additionally, our named executive officers held 387,951 shares of restricted stock on that date, 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, 2018.

Termination and Change in Control Payments Table

Name	Type of Benefit	Before Change in Control Termination w/o Cause or for Good Reason ($)	After Change in Control Termination w/o Cause or for Good Reason ($)(1)	Voluntary Termination ($)	Death / Disability ($)	Change in Control ($)(2)
Robert L.G. Watson	Severance pay	—	1,560,000	—	—	1,560,000
	Option acceleration		24,900		24,900	24,900
	Restricted stock acceleration		57,237		57,237	57,237
	Total		1,642,137		82,137	1,642,137
Steven P. Harris	Severance pay	—	750,000	—	—	750,000
	Option acceleration		—		—	—
	Restricted stock acceleration		54,500		54,500	54,500
	Total		804,500		54,500	804,500
Peter A. Bommer	Severance pay	—	825,000	—	—	825,000
	Option acceleration		8,880		8,880	8,880
	Restricted stock acceleration		31,108		31,108	31,108
	Total		864,988		39,988	864,988
Kenneth W. Johnson	Severance pay	—	825,000	—	—	825,000
	Option acceleration		4,620		8,800	8,800
	Restricted stock acceleration		142,621		142,621	142,621
	Total		972,241		151,421	972,241
Stephen T. Wendel	Severance pay	—	825,000	—	—	825,000
	Option acceleration		10,620		10,620	10,620
	Restricted stock acceleration		31,108		31,108	31,108
	Total		866,728		41,728	866,728

(1) These amounts reflect a lump sum payment equal to 3.0x the named executive officer's annual base salary as of December 31, 2018. The amounts on the option acceleration row reflect 408,500 "in-the-money" unvested options for the named executive officers at an average potential value of $1.09 per share (the difference between the fair market value on December 31, 2018 and the exercise price of the options). Our named executive officers held 290,434 shares of restricted stock valued at the fair market value as of December 31, 2018.

(2) The amounts on the severance pay row reflect a 36-month extension of each named execution officer's employment agreement based on the named executive officer's base salary on December 31, 2018 and would be paid over the extension period. The amounts on the option acceleration row reflect 408,500 "in-the-money" unvested options for the named executive officers at an average potential value of $1.09 per share (the difference between the fair market value on December 31, 2018 and the exercise price of the options). Our named executive officers held 290,434 shares of restricted stock valued at the fair market value as of December 31, 2018.

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 2018, 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. Historically, 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 Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan (the "Directors Plan").

The Directors Plan currently reserves 2,900,000 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, 2018 that Abraxas paid to each director. Abraxas does not sponsor a pension benefits plan, a non-qualified deferred compensation plan or a non-equity incentive plan for its directors; therefore, these columns have been omitted from the following table. Except for reimbursement of travel expenses to attend board and committee meetings, no other or additional compensation for services were paid to any of the directors.

Director Compensation Table

Name	Fees Earned or Paid in Cash ($)(1)	Option Awards ($)(2)	Total ($)(3)
Harold D. Carter	50,000	71,750	121,750
Ralph F. Cox	57,000	71,750	128,750
W. Dean Karrash	53,700	71,750	125,450
Jerry J. Langdon	53,700	71,750	125,450
Dennis E. Logue	52,000	71,750	123,750
Brian L. Melton	64,200	71,750	135,950
Paul A. Powell, Jr.	53,700	71,750	125,450
Edward P. Russell	48,400	71,750	120,150

(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 2018 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, 2018 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, 2018 for our directors:

Outstanding Equity Awards at Fiscal Year End Table

	OPTION AWARDS		
Name	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
	25,000		1.34
	25,000		1.87
	25,000		2.87
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
	12,000		5.38
	25,000		3.66
	25,000		1.34
	25,000		1.87
	25,000		2.87
W. Dean Karrash	12,000		2.90
	12,000		2.39
	12,000		5.38
	25,000		3.66
	25,000		1.34
	25,000		1.87
	25,000		2.87
Jerry J. Langdon	12,000		2.39
	12,000		5.38
	25,000		3.66
	25,000		1.34
	25,000		1.87
	25,000		2.87

Name	OPTION AWARDS Number of Securities Underlying Unexercised Options (Exercisable)	Number of Securities Underlying Unexercised Options (Unexercisable)[1]	Option Exercise Price ($)
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
	25,000		1.87
	25,000		1.34
	25,000		2.87
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
	25,000		1.34
	25,000		1.87
	25,000		2.87
Paul A. Powell, Jr.	10,000		2.75
	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
	25,000		1.34
	25,000		1.87
	25,000		2.87
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
	25,000		1.34
	25,000		1.87
	25,000		2.87

(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 PARTY 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 2018

There were no related party transactions during 2018.

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 Abraxas' independent registered public accounting firm for the fiscal year ending December 31, 2019. 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, 2018. 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.

Assuming the presence of a quorum, the affirmative vote of the holders of a majority of the shares of Common Stock present at the Annual Meeting in person or represented by proxy and entitled to vote on the matter 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, 2019.

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 registered public accounting firm'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 registered public accounting firm (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 registered public accounting firm, BDO USA, LLP, is 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 registered public accounting firm the matters required to be discussed by Public Company Accounting Oversight Board ("PCAOB") Auditing Standards 1301, *Communications with Audit Committees*.

3. The Audit Committee has received the written disclosures and the letter from the independent registered public accounting firm required by applicable requirements of the PCAOB regarding the independent registered public accounting firms' communications with the Audit Committee concerning independence, and has discussed with the independent registered public accounting firm 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, 2018, 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, 2018 and 2017, the reviews of the condensed consolidated financial statements included in Abraxas' quarterly reports on Form 10-Q for the years ended December 31, 2018 and, 2017 and the preparation and delivery of consents, comfort letters and other similar documents, were $473,000 and $510,534, 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, 2018 and, 2017, 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, 2018 and, 2017, were $187,493 and $178,800, 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, 2018 and, 2017, were $0 and $0, respectively.

Consideration of Non-audit Services Provided by the Independent Registered Public Accounting Firm. 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

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 & Analysis, accompanying tables and related narrative contained in this proxy statement beginning on page 17. 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 peer group, within Abraxas' budgetary constraints and commensurate with Abraxas' salary structure;
- rewarding outstanding performance; and
- 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.

Based on the above, and pursuant to Section 14A of the Exchange Act, we request that stockholders approve the compensation of our named executive officers as disclosed in the Compensation Discussion & Analysis, the compensation tables and the related narrative discussion of this proxy statement.

Vote 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 proposal at the annual meeting is necessary to approve this proposal. The enclosed form of proxy provides a means for stockholders to vote for the approval of this proposal. 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 this proposal. Under applicable Nevada law, in determining whether this item has received the requisite number of affirmative votes, broker non-votes will not be counted and will have no effect. Abstentions are treated as present and entitled to vote and will have the same effect as a vote against this item.

As an advisory vote, this proposal is nonbinding. Although the vote is nonbinding, the Board and the Compensation Committee value the opinions of our stockholders and will consider the outcome of the vote when making future compensation decisions for our NEOs. We have held such advisory votes on executive compensation each year since 2011.

The Board of Directors recommends a vote "FOR" the advisory proposal to approve the compensation of our NEOs.

STOCKHOLDER PROPOSALS FOR 2020 ABRAXAS ANNUAL MEETING

Abraxas intends to hold its next annual meeting during the second quarter of 2020, according to its normal schedule. In order to be included in the proxy material for the 2020 Annual Meeting, Abraxas must receive eligible proposals from stockholders intended to be presented at the annual meeting on or before December 5, 2019, 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 2020 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 7, 2020 and the close of business on March 9, 2020 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 2020 Annual Meeting is more than 30 days from May 7, 2020 (the anniversary of the 2019 Annual Meeting), the dates for submission of proposals to be included in the proxy materials and for business to be properly brought before the 2020 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, 2018. 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 3, 2019

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, 2018

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

Commission File Number 001-16071

ABRAXAS PETROLEUM CORPORATION

(Exact name of Registrant as specified in its charter)

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

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

(210) 490-4788

Registrant's telephone number, including area code

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

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

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.

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 every Interactive Data File required to be submitted 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 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 ☐	Smaller reporting company ☐
	Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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, 2018, 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 $470,774,656 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 8, 2019, there were 166,934,860 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2019 Annual Meeting of Stockholders to be held on May 7, 2019.	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 “Business,” “Properties,” “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- the 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 indebtedness and the significant amount of cash required to service our indebtedness,
- the proximity, capacity, cost and availability of pipelines and other transportation facilities,
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by our credit facility and restrictive debt covenants;
- our ability to make planned capital expenditures;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and gas prices;
- 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; and
- other factors discussed elsewhere in this report.

Initial production, or IP, rates, for both our wells and for those wells that are located near our properties, are limited data points in each well’s productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery, or EUR, or economic rates of return from such wells and should not be relied upon for such purposes. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Abraxas standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

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.

"***Boepd***"—barrels of oil equivalents per day.

"***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.

<u>Terms used to assign a present value to or to classify our reserves:</u>

"***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"). 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.

"***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. 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, 2018, our estimated net proved reserves were 67.2 MMBoe, of which 37% were classified as proved developed, 63% were oil and 96% of which (on a Boe basis) were operated by us. Our daily net production for the year ended December 31, 2018 was 9,809 Boepd, of which 64% was oil. 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 Permian/Delaware Basin, the Rocky Mountain, and South Texas. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2018:

	Gross Producing Wells	Average Working Interest	Total Net Acres	Estimated Net Proved Reserves (Mboe)	Estimated Net Proved Reserves % Oil	Net Production (Mboe)	Net Production % Oil
Permian/Delaware Basin	115	74.44%	23,617	41,058	61%	1,328	64%
Rocky Mountain	539	13.80%	20,616	24,331	68%	2,040	66%
South Texas	24	96.88%	12,959	1,839	27%	212	57%
Total United States	678	28.08%	57,192	67,228	63%	3,580	58%

Our properties in the Permian/Delaware Basin region are primarily located in Ward and Winkler Counties, Texas and produce oil and gas primarily from the Bone Spring and Wolfcamp formations.

Our properties in the Rocky Mountain region are primarily located in the Williston Basin of North Dakota and Montana. In this region, our wells produce oil and gas from various reservoirs, primarily the Bakken, Three Forks and Red River formations.

Our properties in the South Texas region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas and the Eagle Ford shale and the Austin Chalk in Atascosa County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation.

Strategy

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

Focus our capital and resources on our core operated basins. Our core basins consist of the Permian/Delaware Basin (Bone Spring and Wolfcamp) and Williston Basin (Bakken and Three Forks). 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. We anticipate making capital expenditures in 2019 of approximately $94.5 million, of which approximately $46.2 million is allocated to acquiring additional acreage and developing our Bone Spring/Wolfcamp properties in the Permian/Delaware Basin. The 2019 budget also allocates approximately $38.3 million for developing our Williston Basin/Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. As part of our efforts to focus our property portfolio, we also seek to sell 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 three core basins. Any proceeds from these asset sales have been and will continue to be used to reduce our indebtedness and/or be redeployed into our core operating basins. We are currently actively working to monetize our remaining Eagle Ford assets in South Texas.

Improve financial flexibility. Our primary sources of capital are availability under our credit facility and cash flows from operations. Availability under our credit facility is subject to a borrowing base which is determined semi-annually by our lenders. The next redetermination is scheduled for April 2019. As of December 31, 2018, we had $180.0 million outstanding on our credit facility and availability of $20.0 million, and we generated approximately $80.0 million of cash flows from operations.

We have also sold producing properties from time to time in order to provide us with financial flexibility. In December 2018 and January 2019, we sold various Eagle Ford assets in our South Texas region for approximately $1.6 million and are currently marketing our remaining Eagle Ford assets. In January 2019, we announced that we had engaged Petrie Partners to assist us in identifying and assessing our options for our Bakken properties. We are still early in this process and do not know the ultimate outcome. In the event that this process were to result in the sale of our Bakken properties, we believe that the proceeds would be used to significantly pay down or fully retire our debt, support our Raven No. 1 rig in the Delaware Basin until it achieves free cash flow and possibly buy back stock.

We seek to reduce the volatility of our cash flows from operations by hedging a portion of our production. As of December 31, 2018, we had NYMEX-based fixed price commodity swap arrangements, on approximately 51% of the oil production from our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021.

During 2018, we had originally established a capital budget of $140.0 million. Capital spending for 2018 was $174.0 million. We exceeded our 2018 capital budget as a result of successfully acquiring more acreage in the Delaware Basin than we had originally budgeted which resulted in increased spending for acquisitions as well as for drilling and completing wells in this area as a result of our higher ownership interests.

We intend to maintain our liquidity and our balance sheet during 2019 by adjusting our capital budget as necessary, seeking to reduce expenses and by funding our capital budget primarily with cash flow from operations.

Profitably grow production and reserves. We have a substantial low-decline legacy production base as evidenced by our approximate 21-year average reserve life as of year-end 2018. 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 own rig in the Williston Basin, and heightened focus on cost control in all of our operated positions both contribute to our historical success in adding low cost barrels to our production base.

2019 Budget and Drilling Activities

Our capital expenditure budget for 2019 is approximately $94.5 million of which approximately $46.2 million is allocated to acquiring additional acreage and developing the Company's Bone Spring/Wolfcamp acreage in the Permian/ Delaware Basin. The budget also allocates approximately $38.3 million to developing our Williston Basin Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. The 2019 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, our financial results 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 world wide 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 from operations, 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 basis differential swap contracts. 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, 2018, two purchasers of production accounted for approximately 57% of our oil and gas sales. During the year ended December 31, 2017, three purchasers of production accounted for approximately 69% of our oil and gas sales and in 2016, two purchasers accounted for approximately 71% 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 2016 to 2018.

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. 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. We possess all material requisite permits required by Federal, state and other local authorities in which we operate properties.

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 ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each 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 sold oil 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, the U.S. Occupational Safety and Health Administration, 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 from operations. 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, construction and permitting requirements on facilities in conjunction with oil and gas operations, including the construction of pollution control devices;
- require protective measures to prevent certain 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 or increase seismic activity;
- restrict the availability of water necessary for hydraulic fracturing operations;
- impose substantial penalties for violations of environmental rules or pollution resulting from our operations;
- curtail production in association with permit limits; and
- curtail or prohibit production for 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 Environmental Protection Agency ("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 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 requirements and liability for failure to meet such requirements, on persons who generate or transport regulated waste materials and also on persons who own or operate a waste treatment, storage or disposal facility. Analogous state laws also impose requirements associated with the management such 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 operations 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. The reach and scope of the CWA, and the determination of what water bodies and land areas are regulated as waters of the U.S., is the subject of various rules adopted by EPA and the U.S. Army Corps of Engineers which we refer to as the WOTUS Rules, and on-going federal court litigation arising out of the rules and recent amendments. The WOTUS Rules, litigation over the rules, and the associated regulatory uncertainty, could impact our operations by subjecting new land and waters to regulation, and increase our cost of operations. 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., or the flow-back of hydraulic fracturing fluids. 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 and more stringent rules for injection wells aimed at reducing the potential for earthquakes associated with injection activities, including new restrictions on siting of such injection wells. We currently own and operate various underground injection wells and rely on third-party owned injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. More stringent regulations of injection wells could additionally increase our cost of operations. 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 operation of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. In the past few years, EPA has adopted new more restrictive regulations governing air emissions from oil and gas operations, including regulations which restrict 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 us to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to more stringent regulation under the CAA. Failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. We may be required to incur 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, but where these operations occur on federal or tribal lands they are subject to regulation by the U.S. Department of the Interior, Bureau of Land Management ("BLM"). In addition to federal legislative and regulatory actions, 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 hydraulic fracturing, 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 the availability of water for hydraulic fracturing. If these types of restrictions are widely adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells, and these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with water wells in the vicinity of an oil or gas well or other alleged environmental problems. Additional information concerning hydraulic fracturing is included under Item 1A "Risk Factors."

Climate Change and Greenhouse Gas Regulation. Scientific studies 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 efforts spearheaded by the United Nations . Domestically, the Fourth National Climate Assessment report, released in November 2018, noted that climate change is mostly driven by GHG emissions and that climate change is accelerating. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered GHGs. We expect continuing debate, especially in the political arena, over how to address climate change and what policies and regulations are necessary to address the issue. It is possible that domestic and international regulations addressing climate change 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. Given widely divergent political views on climate change regulation, we are unable to predict the timing, scope and effect of any 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. In addition, several states and local governments have adopted, or are considering adopting, regulations or ordinances to reduce emissions of GHGs. 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. The various efforts to regulate the emissions of GHGs (including lawsuits pending in United States federal courts) may affect the cost of our operations, may affect the public's perception of our industry, and may reduce demand for our products.

An example of the uncertainty in regulations comes from the BLM flaring rule. In November 2016, BLM issued a final rule to further restrict venting and flaring of gas from oil and gas operations on public lands. Then, BLM issued a stay of these requirements in December 2017. In September 2018, BLM published a final rule to modify and rescind substantial portions of the flaring rule. The rescission was challenged by litigation filed in the U.S. District Court for the Northern District of California. If the litigation is successful and the rule restricting flaring of gas were to become effective, we would have to curtail production from the affected wells and would incur additional costs of compliance as well as increased monitoring and recordkeeping for some of our facilities.

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. "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 may 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 and increase the cost of such operations.

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 renewed efforts by certain environmental activists to use the ESA as a mechanism to restrict land development and energy production. Such listings could include habitat in areas where we operate or plan to operate, or which could adversely affect our ability to secure needed sand, water or other materials for our operations or to transport oil or gas via pipeline to our customers. Further, some of the species could become subject to voluntary rangeland conservation plans that could affect our operations of sources of materials. 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 8, 2019, we had 100 full-time employees. We retain independent geological, land, marketing, engineering and health and safety consultants from time to time and expect to continue to do so in the future.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). You may read and copy any document we file with the SEC at the SEC's public reference room at 100

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

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

Item 1A. Risk Factors

Risks Related to Our Business

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

At December 31, 2018, we had a total of $180.0 million of indebtedness under our credit facility and total indebtedness of $183.4 million (including the current portion). While the amount borrowed under our credit facility at March 8, 2019 was $180.0 million (and total indebtedness was $183.3 million), this amount will likely increase as we pursue drilling and completion of wells. 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;
- requiring us to meet financial tests contained in our credit facility and future debt arrangements that may affect our flexibility in planning for and reacting to changes in our business, including future business opportunities;
- requiring us to use 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
- making us more vulnerable to competitive pressures if there is a downturn in our business or the economy in general, than our competitors with less debt.

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

A breach of the terms and conditions of our credit facility, including the inability to comply with the required financial covenants, could result in an event of default. If an event of default occurs (after any applicable notice and cure periods), the lenders would be entitled to terminate any commitment to make further extensions of credit under our credit facility and to accelerate the repayment of amounts outstanding (including accrued and unpaid interest and fees). Upon a default under our credit facility, the lenders could also foreclose against any collateral securing such obligations, which may be all or substantially all of our assets. If that occurred, we may not be able to continue to operate as a going concern. As of December 31, 2018, the Company was in violation of its current ratio covenant under its credit facility. A waiver of this violation has been obtained. We cannot assure you that we will be able to obtain similar waivers in the future.

Depressed 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. Oil, gas and NGL prices have been more volatile since the second half of 2014, when there was a significant decline in oil, gas and NGL prices, which adversely affected our operating results and contributed to a reduction in our anticipated future capital expenditures. Prices improved in 2017 and 2018 before declining in the last quarter of 2018. In addition to the impact on our results of operations, declines in oil and gas prices could cause us to write down the value of our estimated proved reserves. For example, the decline in commodity prices prior to 2017 adversely impacted our estimated proved reserves and resulted in a proved property impairment of $67.6 million in 2016. We could record impairments in future periods, the amount of which will be dependent upon many factors such as future prices of oil, gas and NGL, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions.

While oil and gas prices began to improve in late 2016 and remained at somewhat improved levels in 2017 and 2018, prices have remained relatively low and price volatility has continued. 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, cash flows from operations and profitability;
- causing us to 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 from operations, 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.

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, which are also known as midstream facilities, owned and operated by third parties. Transportation space on such gathering systems and pipelines is 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 adequate transportation and storage options are not available to us, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas. For example, our principal third party provider in the Bakken Field for these services has experienced significantly increased gathering system pressures which have resulted in capacity constraints. These constraints, in turn, have restricted our production and required us to flare gas, decreasing the volumes sold from our wells. Similarly, rapid production growth in the Permian Basin has strained the available midstream infrastructure there with adverse effects on our operations.

In addition to causing production curtailments and reducing the price we receive for the oil, gas and NGL we produce, given environmental impacts, including GHG production, regulatory agencies including the North Dakota Industrial Commission have adopted policies to reduce the volume of flared gas, the number of wells flaring and the duration of flaring. While these regulations have not had a material adverse effect on us to date, these current regulations relating to flaring gas or the adoption of additional regulations could cause us to shut-in production or curtail the drilling of new wells either of which could have a material adverse effect on us.

We rely on third parties to continue to construct additional midstream facilities and related infrastructure to accommodate our growth, and the ability and willingness of those parties to do so is subject to a variety of risks.

For example:

- Decreases in commodity prices in recent years have resulted in reduced investment in midstream facilities by some third parties;
- Various interest groups have protested the construction of new pipelines, and particularly pipelines near water bodies, in various places throughout the country, and protests have at times physically interrupted pipeline construction activities;
- Some companies in our industry have sought to reject volume commitment agreements with midstream providers in bankruptcy proceedings, and the risk that such efforts will succeed, or that upstream energy company counterparties will otherwise be unable or unwilling to satisfy their volume commitments, may have the effect of reducing investment in midstream infrastructure; and

We have pursued a variety of strategies to alleviate some of the risks associated with the midstream services and facilities upon which we rely, including seeking alternative sources for processing and transporting gas that we produce. There can be no assurance that the strategies we pursue will be successful or adequate to meet our needs.

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 $200.0 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. A number of factors could reduce our borrowing base, including:

- lower commodity prices or production;
- a reduction in reserve estimates;
- 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 8, 2019, we had $180.0 million of borrowings outstanding and availability of $20.0 million 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 operations and cash flows from operations. 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 in the past 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 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 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 flows from operations, borrowings under credit facilities, sales of properties, monetizing derivative contracts and sales of debt and equity securities and we expect to continue to utilize these sources in the future to the extent available. 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 flows from operations. Lower prices and/or lower production could also decrease revenues and cash flows from operations, 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 flows from operations does not increase as a result of capital expenditures, a greater percentage of our cash flows from operations will be required for debt service and operating expenses and our capital expenditures would, by necessity, be decreased.

If cash flows from operations or our borrowing base decrease, 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 production from 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.

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 downturn in our business or the economy in general or otherwise conduct necessary or desirable business activities. We are also required to use the proceeds from the termination of any derivative contracts to repay outstanding amounts under the credit facility and to use any amount of cash on hand and liquid investments in excess of $10.0 million to repay outstanding amounts under the credit facility.

A breach of any of these covenants could result in a default under our credit facility. For example, at December 31, 2018, we were not in compliance with the current ratio under our credit facility. While we received a waiver of this default, we cannot assure you that we will be able to obtain such waivers in the future. 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 flows 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 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.

During 2016, the net capitalized costs of our oil and gas properties exceeded the present value of estimated future cash flows from our proved reserves, resulting in recognition of impairments totaling $67.6 million. While we did not recognize any impairments in 2017 or 2018, if commodity prices decrease in the future, we would likely be required to record further write downs.

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 flows 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 gas sales contract related to certain gas and NGL produced in the Rocky Mountain Region, which provides that if certain margins of gas and NGL prices are not met by the purchaser, we receive no sales proceeds.

During 2018, our differentials averaged ($7.39) per Bbl of oil and ($1.36) per Mcf of gas. Approximately 57% of our oil production during 2018 was from the Rocky Mountain region and approximately 37% from the Permian region. As our production from the Rocky Mountain and Permian regions continues to increase, we expect that the effect 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 flows.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and gas, we enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 51% of the oil production from our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021.These arrangements may be inadequate to protect us from declines in oil and gas prices. 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 flows from operations could be affected if the basis differentials widen more than we anticipate. We have entered into basis swaps to mitigate some of the effects of differentials, however they do not alleviate all of the effects of such differentials. Our cash flows 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 flows from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows from operations.

If the prices at which we hedge our oil and gas production are less than current market prices, our cash flows 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, 2018, we recognized a gain on our oil and gas derivative contracts of $8.1 million, consisting of a loss of $19.0 million on our settled contracts and a gain of $27.1 million on open contracts. The loss on settled contracts resulted in a decrease in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility.

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

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

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

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 flows from operations.

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, 2018 include proved undeveloped reserves and proved developed reserves that are behind pipe of 29,448 MBbls of oil, 6,355 MBbls of NGL and 50,567 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, 2018 were undeveloped, and those proved reserves may not ultimately be developed.

At December 31, 2018, approximately 63% of the Company's total estimated proved reserves on a Boe basis were undeveloped. Recovery of proved undeveloped 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 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 flows and income from operations are highly dependent on successfully developing its proved undeveloped leasehold acreage.

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, 2018, our average annual estimated decline rate for our net proved developed producing reserves is 35%; 19%; 14%; 11% and 9% in 2019, 2020, 2021, 2022 and 2023, respectively, 11% in the following five years, and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially higher. 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 63% of our total estimated proved reserves on a Boe basis at December 31, 2018 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 63% of our total estimated proved reserves on a Boe basis as of December 31, 2018 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. If the volume of oil and gas we produce decreases, our cash flows 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 be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

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. For example, we have in the past, and may be required in the future, to delay drilling or completing wells in order to protect them from fracture stimulation of other wells in the same area.

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. Non-operated properties represented approximately 4% of our estimated net proved reserves on a Boe basis. at December 31, 2018. As a result, we have limited ability to exercise influence over and control the risks associated with operation of these properties. The failure of an operator to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including:

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

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

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

Our operations could be adversely affected by weather conditions and wildlife restrictions on federal leases. In the Williston Basin, drilling and other oil and gas activities cannot be conducted as efficiently 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 has been 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;
- delays due to protection from fracture stimulations of nearby wells,
- 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, 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, 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 hydrocarbon-bearing 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 implemented disclosure requirements related to chemicals used in hydraulic fracturing, and while the BLM has rescinded its rules governing hydraulic fracturing on federal and tribal lands (which action itself is subject to pending litigation), we anticipate further regulation of hydraulic fracturing and related activities by states and local governments. 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 addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development or production activities.

Certain states in which we operate, including Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosures, and/or well-construction requirements on hydraulic-fracturing operations. 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.

See “Item 1. Business – Environmental Matters – Hydraulic Fracturing” above for additional discussion related to environmental risks associated with our hydraulic fracturing activities.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows from operations.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Over the past few years, extreme drought conditions persisted in West and South Texas. Although conditions have improved, we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local resources, we may be unable to economically produce oil and gas, which could have an adverse effect on our financial condition, results of operations and cash flows from operations.

Studies noting a connection between increased seismic activity and the injection of wastewater from oil and gas operations could result in new laws or regulations which would increase our cost of operations.

Some studies have noted an increase in localized frequency of seismic activity associated with underground injection wastewater from oil and gas operations. If the results of these studies are confirmed, new legislative and regulatory initiatives could require additional monitoring, restrict the injection of produced water in certain disposal wells or modify or curtail hydraulic fracturing operations. These actions could lead to operational delays, increased compliance costs or otherwise adversely impact our operations.

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 U.S. 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;
- reduce access to sand, or other proppants, required for hydraulic fracturing;
- 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.

Costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities could be 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 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 (as modified and re-proposed on December 30, 2016), 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 proposed to be exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, on December 16, 2016, the CFTC 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, on July 19, 2012, the CFTC 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 and requirements could increase the costs to us of entering into, and lessen the availability to us, derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business.

It is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements. Moreover, 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 may affect whether we are required to comply with margin and certain clearing and trade-execution requirements in connection with our derivative activities. If we do not qualify for the commercial end-user exception, we may be required to post margin or clear certain transactions, which could reduce our liquidity and cash available for capital expenditures and our ability to hedge may be impacted. 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 derivatives with us, which could increase the costs to us of entering into, and lessen the availability of us to, derivative contracts. 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 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.

In addition, federal banking regulators have adopted new capital requirements for certain regulated financial institutions in connection with the Basel III Accord. The Federal Reserve Board also issued proposed regulations on September 30, 2016, proposing to impose higher risk-weighted capital requirements on financial institutions active in physical commodities, such as oil and gas. If and when these proposed regulations are fully implemented, financial institutions subject to these higher capital requirements may require that we provide cash or other collateral with respect to our obligations under the financial derivatives and other contracts we may enter into with such financial institutions in order to reduce the amount of capital such financial institutions may have to maintain. Alternatively, financial institutions subject to these capital requirements may price transactions so that we will have to pay a premium to enter into derivatives and other physical commodity transactions in an amount that will compensate the financial institutions for the additional capital costs relating to such derivatives and physical commodity transactions. Rules implementing the Basel III Accord and higher risk-weighted capital requirements could materially reduce our liquidity and increase the cost of derivative contracts and other physical commodity contracts (including through requirements to post collateral, which could adversely affect our available capital for other commercial operations purposes). In addition, certain foreign jurisdictions may adopt or implement laws and regulations relating to margin and central clearing requirements, which in each case may affect our counterparties and the derivatives markets generally.

If we reduce our use of derivative contracts as a result of any of the foregoing regulations or requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, gas, and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, gas, and NGL. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations, or cash flows from operations.

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, 2018, we had pre 2018 net operating loss carryforwards or NOLs, for federal income tax purposes of $245.2 million and a 2018 NOLs of $46.8 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 NOLs 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.

As a result of the Tax Cuts and Jobs Act of 2017, NOLs arising before January 1, 2018, and NOLs arising after January 1, 2018, are subject to different rules. Our pre- 2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018, can generally be carried forward indefinitely and can offset up to 80% of future taxable income. Our ability to use our NOLs during this period will be dependent on our ability to generate taxable income, and the NOLs 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 attacks in the future. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber attacks.

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

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

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

We depend to a large extent on Robert L.G. Watson, our President and Chief Executive Officer, for our management, 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 good reason, 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 from operations, profitability and growth.

Our revenue, cash flows from operations, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Prices also affect the amount of cash flows 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, 2018 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 present value of 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, 2018. The average realized sales prices used for purposes of such estimates were $59.65 per Bbl of oil and $1.76 per Mcf of gas. The December 31, 2018 estimates also assume that we will make future capital expenditures of approximately $547.2 million in the aggregate primarily from 2019 through 2023, 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 63% of our total estimated proved reserves on a Boe basis as of December 31, 2018 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, 2018 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2018 and costs in effect on December 31, 2018, 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 flows, 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.

Recently enacted federal legislation will affect our tax position concerning tax deductions currently available with respect to oil and gas drilling may adversely affect our net earnings.

In December 2017, Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act, or TCJA. The law made significant changes to U.S. federal income tax laws, including reducing the corporate income tax rate from 35 percent to 21 percent, repealing the corporate alternative minimum tax, or AMT, partially limiting the deductibility of interest expense and NOLs, eliminating the deduction for certain U.S. production activities and allowing the immediate deduction of certain new investments in lieu of depreciation expense over time. Many aspects of the TCJA are unclear and may not be clarified for some time.

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.

Climate change and regulations related to GHGs could have an adverse effect on our operations and on the demand for oil and gas.

Scientific studies have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. Domestically, the Fourth National Climate Assessment report, released in November 2018, noted that climate change is mostly driven by GHG emissions and that climate change is accelerating. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered GHGs. We expect continuing debate, especially in the political arena, over how to address climate change and what policies and regulations are necessary to address the issue. In response to various scientific studies, governments have begun adopting domestic and international climate change regulations that require reporting and reduction of emissions of GHGs. It is possible that international efforts spear-headed by the United Nations 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 and local level, several states and localities, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of GHGs. At the federal 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 Congress. 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.

Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs 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.

In addition, local weather effects associated with climate change, including more severe rainfall events, more intense storms, flooding, or droughts could adversely affect our facilities or the scheduling of deliveries or the cost of supplies needed to run our business.

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

Effective December 2015, the EPA adopted 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. EPA has now issued new area designations with respect to ground-level ozone, and in November 2018 EPA issued final requirements for implementation that apply to state and local agencies. Areas of the country that have been reclassified so that they are no longer in attainment with the 2015 standard will be more costly and difficult for operators to construct new or modified sources of air pollution, including those associated with our operations. Moreover, such reclassified areas more stringent regulations may require among other things, 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 from operations.

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 400,000,000 shares of common stock with such rights as determined by our board of directors. In the future, we may increase our authorized shares of common stock or 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, 2018, we had 166,713,784 shares of common stock outstanding of which 4,179,187 shares were held by affiliates and, in addition, 7,549,448 shares of common stock were subject to outstanding options granted under stock option plans (of which 6,478,948 shares were vested at December 31, 2018).

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, 2018.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage(1)		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres(2)
Permian/Delaware Basin	15,639	11,566	13,986	9,415	12,648	2,391	23,372
Rocky Mountain	27,376	14,500	12,343	5,769	3,078	346	20,615
South Texas	7,982	7,502	4,745	4,688	2,603	739	12,929
Total	50,997	33,568	31,074	19,872	18,329	3,476	56,916

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

(2) Includes 640 net acres in the Permian Basin region that are included in both developed and fee mineral acres.

The following table sets forth Abraxas' net undeveloped acreage subject to expiration by year:

	2019	2020	2021	2022	2023
Permian/Delaware Basin	176	315	—	—	—
Rocky Mountain	3	426	—	—	—
South Texas	1,798	2,020	—	—	—
Total	1,977	2,761	—	—	—

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2018:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Permian/Delaware Basin	63.0	52.4	52.0	33.3
Rocky Mountain	228.0	67.6	311.0	6.8
South Texas	15.0	15.0	9.0	8.3
	306.0	135.0	372.0	48.4

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.

The Company's proved oil and gas reserves have been estimated by an independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2016, and 2017 and LaRoche Petroleum Consultants as of December 31, 2018, assisted by the engineering and operations departments of the Company. For the year ended December 31, 2018, LaRoche Petroleum Consultants, Ltd., of Dallas, Texas estimated reserves for our 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 LaRoche Petroleum Consultants, Ltd. to prepare reserve estimates for these properties as they are located in a widely dispersed geographic area and have relatively low value. LaRoche Petroleum Consultants, Ltd's reserve report as of December 31, 2018 included a total of 316 properties and our internal report included 201 properties.

The technical personnel responsible for preparing the reserve estimates at LaRoche Petroleum Consultants, Ltd. 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. LaRoche Petroleum Consultants, Ltd. 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 LaRoche Petroleum Consultants, Ltd. were developed utilizing their own geological and engineering data, supplemented by data provided by Abraxas. The report of LaRoche Petroleum Consultants, Ltd. dated February 12, 2019, which contains further discussions of the reserve estimates and evaluations prepared by LaRoche Petroleum Consultants, Ltd. as well as the qualifications of LaRoche Petroleum Consultants, Ltd.'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, 2018 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 40 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, including oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages, were 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 Financial Accounting Standards Board, or 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, 2018, 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, 2018. All of our reserves are located in the United States.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2018

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil equivalents (MBoe)
Proved				
Developed	13,586	3,804	43,271	24,602
Undeveloped	28,651	6,230	46,473	42,626
Total Proved	42,237	10,034	89,744	67,228

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2016, 2017, and 2018, 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, 2018. 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, 2018 report. The average realized sales prices used for purposes of such estimates were $59.65 per Bbl of oil and $1.76 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $547.2 million in the aggregate primarily in the years 2019 through 2023, 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 flows 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, 2018 and 2017, the Company's net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. During 2016, we recorded a proved property impairment of $67.6 million. If commodity prices decrease, we could be required to further write down the carrying value of our reserves during 2019 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 that occurred during 2018 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 year. 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 were no PUDs as of December 31, 2016, 2017 and 2018 as set forth in this report that are not planned to be developed within five years.

The following is a summary of the changes to the Company's proved undeveloped reserves that occurred during 2018:

	MBoe
PUDs at December 31, 2017	43,631
Revisions of prior estimates	3,040
Extensions, discoveries, and other additions	13,303
Conversion to developed	(5,811)
Conversion to probable	(8,078)
Sales	(3,459)
PUDs at December 31, 2018	42,626

We spent approximately $56.3 million converting proved undeveloped reserves to proved developed reserves in 2018. The following is a summary of the changes to the Company's proved undeveloped reserves that occurred during 2018.

Revisions of prior estimates:

An increase of 3,040 MBoe of net reserves was attributed to increased economic life calculations at the higher commodity pricing experienced during 2018.

Extensions, discoveries and other additions:

The Company added sixteen new proved undeveloped Wolfcamp A locations, and three 3rd Bone Spring locations in Ward County, Texas, accounting for 8,530 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing wells or those operated by others. The Company added two new proved undeveloped Middle Bakken locations, and one Three Forks location in McKenzie County, North Dakota, accounting for 1,692 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing well or those operated by others. The Company purchased two proved undeveloped non-operated locations in Ward County, Texas during 2018 accounting for 411 MBoe of net reserves. The Company also converted five probable undeveloped Wolfcamp A locations, and one Wolfcamp B locations in Ward County, Texas, to proved undeveloped reserves during 2018 accounting for 2,670 MBoe of net reserves.

Conversion to developed:

The Company converted four proved undeveloped Wolfcamp A locations in Ward County, Texas, to proved developed reserves during 2018 accounting for 917 MBoe of net reserves. The Company converted thirteen proved undeveloped Bakken and Three Forks locations in McKenzie County, North Dakota, to proved developed reserves during 2018 accounting for 4,452 MBoe of net reserves. There was also one proved undeveloped Bakken location in McKenzie County, North Dakota, converted to proved non-producing reserves during 2018 accounting for 415 MBoe of net reserves. Also, there were nine non-operated proved undeveloped Bakken and Three Forks locations in McKenzie County, North Dakota, converted to proved developed producing reserves during 2018 accounting for 24 MBoe of net reserves. There was also one non-operated proved undeveloped Bakken location in McKenzie County, North Dakota, converted to proved non-producing reserves during 2018 accounting for 3 MBoe of net reserves.

Conversion to probable:

The Company converted twenty-two proved undeveloped Three Forks 2nd Bench locations in McKenzie County, North Dakota, to probable undeveloped reserves during 2018 accounting for 6,885 MBoe of net reserves. There was also one proved undeveloped Rockies location in Billings County, North Dakota, converted to probable undeveloped reserves during 2018 accounting for 136 MBoe of net reserves. Also, there were twelve non-operated proved undeveloped Bakken and Three Forks locations in McKenzie County, North Dakota, converted to probable undeveloped reserves during 2018 accounting for 1,052 MBoe of net reserves. There was one non-operated proved undeveloped Rockies location in Billings County, North Dakota, converted to probable undeveloped reserves during 2018 accounting for 5 MBoe of net reserves. All of these locations are no longer included in the Company's five-year development schedule.

Sold:

The Company sold two properties in Ward County, Texas that included 3,459 MBoe of net proved undeveloped Montoya reserves.

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 the standardized measure of discounted future net cash flows to PV-10 at December 31, 2017 and 2018:

	December 31,	
	2017	2018
	(In thousands)	
Standardized measure of discounted future net cash flows	$405,741	$651,884
Present value of future income taxes discounted at 10%	21,700	37,413
PV-10	$427,441	$689,297

Oil and Gas Production, Sales Prices and Production Costs

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

	2016	2017	2018
Oil Production (Bbl)			
Permian	85,966	358,158	843,235
Rocky Mountain	1,102,852	1,094,170	1,343,666
South Texas	183,543	121,195	120,987
Total	1,372,361	1,573,523	2,307,888
Gas Production (Mcf)			
Permian	742,280	1,476,021	1,948,092
Rocky Mountain	1,756,462	1,910,876	2,122,215
South Texas	660,978	502,276	516,493
Total	3,159,720	3,889,173	4,586,800
NGL Production (Bbl)			
Permian	52,294	106,521	159,756
Rocky Mountain	300,669	364,202	342,482
South Texas	10,376	5,221	5,855
Total	363,339	475,944	508,093
Total Production (Boe)(1)	2,262,320	2,697,664	3,580,450
Average sales price per Bbl of oil(2)			
Permian	$ 41.30	$ 49.48	$ 55.95
Rocky Mountain	$ 36.31	$ 45.40	$ 57.80
South Texas	$ 40.13	$ 51.09	$ 66.66
Composite	$ 37.14	$ 46.76	$ 57.59
Average sales price per Mcf of gas			
Permian	$ 2.25	$ 2.05	$ 1.38
Rocky Mountain	$ 0.61	$ 1.41	$ 1.84
South Texas	$ 1.87	$ 2.34	$ 2.41
Composite	$ 1.26	$ 1.77	$ 1.71
Average sales price per Bbl of NGL			
Permian	$ 12.70	$ 17.28	$ 18.05
Rocky Mountain	$ 2.64	$ 10.36	$ 15.34
South Texas	$ 8.94	$ 17.78	$ 23.15
Composite	$ 4.27	$ 11.99	$ 16.28
Average sales price per Boe(2)	$ 24.97	$ 31.95	$ 41.62
Average cost of production per Boe produced(3)			
Permian	$ 13.97	$ 5.87	$ 6.59
Rocky Mountain	$ 3.68	$ 4.20	$ 6.13
South Texas	$ 16.54	$ 15.46	$ 15.79
Composite	$ 6.60	$ 5.51	$ 6.87

(1) Oil and gas were combined by converting gas to Boe on the basis of 6 Mcf of gas to 1 Bbl of oil.
(2) Before the impact of hedging activities.
(3) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

Within the above major operating regions, the Rocky Mountain and the Permian/Delaware regions represented more than 15% of our proved reserves as of December 31, 2018. The following is a summary, by product sold, for each primary field in these regions, which represented 15% or more of our total proved reserves as of December 31, 2018, for the three years ended December 31:

	2016	2017	2018
Rocky Mountain Region			
Oil production (Bbls)			
Bakken/Three Forks	997,641	990,959	1,213,782
Gas Production (Mcf)			
Bakken/Three Forks	1,437,965	1,674,870	1,932,330
NGL production (Bbls)			
Bakken/Three Forks	286,232	357,850	341,191
Average sales price per Bbl of oil(1)			
Bakken/Three Forks	$ 36.38	$ 45.38	$ 57.77
Average sales price of per Mcf of gas			
Bakken/Three Forks	$ 0.40	$ 1.30	$ 1.76
Average sales price per Bbl of NGL			
Bakken/Three Forks	$ 2.00	$ 10.12	$ 15.36
Average cost of production per Boe produced(2)	$ 2.40	$ 3.15	$ 4.88
Permian Region			
Oil production (Bbls)	21,976	298,287	756,643
Wolfcamp			
Gas Production (Mcf)	13,002	238,711	640,273
Wolfcamp			
NGL production (Bbls)	2,918	44,159	100,141
Wolfcamp			
Average sales price per Bbl of oil(1)	$ 49.75	$ 49.91	$ 55.79
Wolfcamp			
Average sales price of per Mcf of gas	$ 3.57	$ 2.04	$ 1.31
Wolfcamp			
Average sales price per Bbl of NGL	$ 19.32	$ 18.16	$ 18.34
Wolfcamp			
Average cost of production per Boe produced(2)	$ 2.47	$ 1.58	$ 5.34

(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:

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Permian/Delaware	1.0	1.0	—	—	—	—
Rocky Mountain	—	—	—	—	—	—
South Texas	1.0	1.0	1.0	1.0	—	—
Total	2.0	2.0	1.0	1.0	—	—
Development						
Productive						
Permian/Delaware	—	—	7.0	6.5	11.0	7.4
Rocky Mountain	6.0	4.7	14.0	5.1	36.0	6.4
South Texas	—	—	—	—	—	—
Total	6.0	4.7	21.0	11.6	47.0	13.8

In addition to the above drilling activity, as of December 31, 2018 we had 8.00 gross (4.2 net) operated wells and 2.0 gross (0.6 net) non-operated wells that were drilled and uncompleted that are not represented in the above table.

Present Activities

Williston Basin, North Dakota

Western North Dakota has experienced one of the coldest winters on record. Abraxas has experienced several days when all surface work was shut down due to temperatures and wind chill that put personnel safety and equipment reliability in jeopardy. Our Ravin NE Pad is still under production restriction due to a natural gas pipeline installation delay requiring the flaring of all gas production from this pad. The pipeline is scheduled to be in service within the next two weeks at which point we are expecting normal production operations to be resumed. The Abraxas Raven Rig#1 is scheduled to be started up within the next several months to begin drilling operations on the six well Jore Extension Pad.

Delaware Basin, West Texas

In the Delaware Basin of West Texas, the Company has successfully drilled, completed and started flowback on the two well Creosote Pad in Ward County, where Abraxas now owns an approximate 95% working interest. The Wolfcamp A-1 and A-2 were targeted with a 26 stage fracture treatment (frac) in 5,000' laterals. The one well Hackberry pad has been successfully drilled and a 26 stage fracture treatment in the Wolfcamp A-1 is scheduled to start next Monday. Abraxas owns an approximate 75% working interest in this 5,000' lateral well located in Winkler County. The Company is currently drilling a two well pad, Woodberry, in which we own a 100% working interest. The Woodberry Pad adjoins our Caprito block in Ward County.

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.

Other Properties

We own 15.3 acres of land in Atascosa County, Texas, 1.5 acres of land and an office building in Ward County, Texas and an office building and lot in Niobrara County, Wyoming, 50 acres of land in DeWitt County, Texas and 582 acres of land, with shop and office, in McKenzie County, North Dakota. We own 23 vehicles which are used in the field by employees. We also own a workover rig, which is used for servicing our wells. Raven Drilling owns a 2000 HP drilling rig, primarily used for drilling wells in the Williston Basin. In North Dakota, we own three houses and a man-camp 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, 2018, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

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

Market Information

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

Period	High	Low
2017		
First Quarter	$2.99	$1.52
Second Quarter	2.34	1.45
Third Quarter	2.10	1.51
Fourth Quarter	2.55	1.85
2018		
First Quarter	$2.75	$2.03
Second Quarter	3.27	2.11
Third Quarter	3.23	2.05
Fourth Quarter	2.45	0.90
2019		
Through March 8, 2019	$1.46	$1.01

Holders

As of March 8, 2019, we had 166,934,860 shares of common stock outstanding and approximately 908 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.

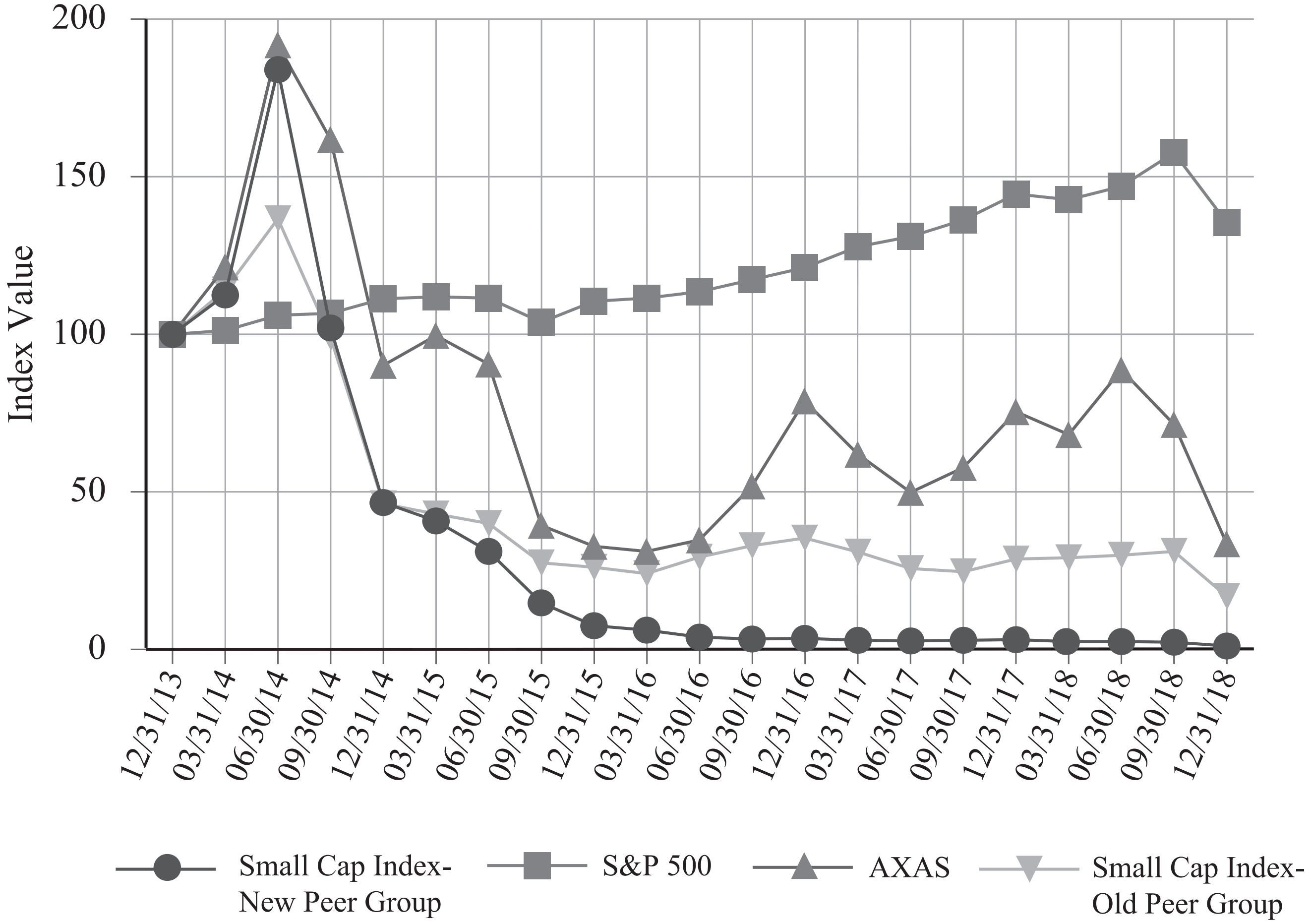
Performance Graph

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 2017 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, in 2018 the following were the comparable companies utilized in the graph below: Approach Resources, Inc. (AREX), Contango Oil & Gas Company (MCF), Earthstone Energy, Inc. (ESTE), Ring Energy, Inc. (REI) and Rosehill Resources Inc. (ROSE). Halcon Resources Corporation (HK) and Lillis Energy Inc. (LLEX) were added to the list in 2018 based upon the criteria originally utilized by L&A. Gastar Exploration Inc. (GST) and Lonestar Resources US Inc. (LONE) were removed from the list as they were no longer comparable companies due to market capitalization or lack of operational similarities

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, 2013, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2014, 2015, 2016, 2017 and 2018.



	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018
Small Cap Index—New Peer Group	$100.00	$ 46.56	$ 7.37	$ 3.26	$ 2.91	$ 0.92
Small Cap Index—Old Peer Group	$100.00	$ 46.18	$ 26.02	$ 35.27	$ 28.57	$ 16.73
S&P 500	$100.00	$111.39	$110.58	$121.13	$144.65	$135.63
AXAS	$100.00	$ 90.16	$ 32.51	$ 78.81	$ 75.44	$ 33.43

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, 2014 through 2018. 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,				
	2014	2015	2016	2017	2018
	(In thousands, except per share data)				
Total revenue—continuing operations	$133,776	$ 67,030	$ 56,555	$ 86,264	$149,167
Net income (loss)	$ 63,269	$(127,110)	$ (96,378)	$ 16,006	$ 57,821
Net income (loss) from continuing operations	$ 61,951	$(127,090)(2)	$ (96,378)(3)	$ 16,006	$ 57,821
Net income (loss) from discontinued operations—net of tax	$ 1,318(1)	$ (20)	$ —	$ —	$ —
Net income (loss) per common share—diluted—continuing operations	$ 0.61	$ (1.21)	$ (0.79)	$ 0.10	$ 0.34
Weighted average shares outstanding—Diluted	101,468	104,605	122,132	162,844	167,689
Total assets	$374,899	$ 267,872	$161,648	$273,806	$425,890
Long-term debt, excluding current maturities	$ 76,554	$ 138,402	$ 96,616	$ 87,354	$183,091
Total stockholders' equity	$207,495	$ 84,465	$ 18,505	$106,308	$166,510

(1) Includes a gain of $1.9 million on the sale of our Canadian subsidiary.
(2) Includes proved property impairment of $128.6 million.
(3) Includes proved property impairment of $67.6 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 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 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 2019 will impact the amount of cash generated from operating activities, which will in turn impact our financial position. As of March 8, 2019, the NYMEX oil and gas price was $56.07 per Bbl of oil and $2.87 per Mcf of gas, respectively.

During 2018, the NYMEX future price for oil averaged $64.98 per barrel as compared to $50.85 per barrel in 2017 and the NYMEX future spot price for gas averaged $3.07 per Mcf compared to $3.14 per Mcf in 2017. Prices closed on December 31, 2018 at $45.41 per Bbl of oil and $2.94 per Mcf of gas. If commodity prices decline from these levels, our revenue and cash flows 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 decline, our revenues, profitability and cash flows 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 scheduled to be redetermined on March 28, 2019.

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, 2016, 2017 and 2018:

	Oil			Gas		
	2016	2017	2018	2016	2017	2018
Average realized price(1)	$37.14	$46.76	$57.59	$ 1.26	$ 1.77	$ 1.71
Average NYMEX price	$43.47	$50.85	$64.98	$ 2.55	$ 3.14	$ 3.07
Differential	$ (6.33)	$ (4.09)	$ (7.39)	$(1.29)	$(1.37)	$(1.36)

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

The Company’s derivative contracts as of December 31, 2018 consisted of NYMEX-based fixed price swaps and basis differential swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party.

Our hedging arrangements equate to approximately 51% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021. 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 flows from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flows on the portion of the production that has been hedged. We have in the past and will in the future sustain losses on both open and settled 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 2016, we incurred a loss of $18.0 million, consisting of a gain of $1.8 million on closed contracts and a loss of $19.8 million related to open contracts. In 2017, we incurred a loss of $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million related to open contracts. In 2018, we recorded a gain of $8.1 million, consisting of a loss of $19.0 million on closed contracts and a gain of $27.1 million related to open contracts. We have not designated any of these derivative contracts as a hedge as permitted by applicable accounting rules if certain conditions are met.

The following table sets forth our derivative contracts at December 31, 2018:

	Oil—WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
January—December 2019	2,941	$56.20
January—December 2020	2,204	$54.35
January—December 2021	1,815	$60.32
Basis Swaps		
January—December 2019	4,000	$ 2.98
January—December 2020	4,000	$ 2.98

At December 31, 2018, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $15.1 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 report as of December 31, 2018, our average annual estimated decline rate for our net proved developed producing reserves is 35%; 19%; 14%; 11% and 9% in 2019, 2020, 2021, 2022 and 2023, respectively, 11% in the following five years, and approximately 8% 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.

In addition to our ability to successfully drill wells, we must also market our production which depends substantially on the availability, proximity and capacity of gathering systems, pipelines and processing facilities, which are also known as midstream facilities, owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations could be adversely affected. Both of our principal areas of operation (the Bakken and Permian Basin) have experienced substantial development in recent years, and this has made it more difficult for providers of midstream infrastructure and services to keep pace with the corresponding increases in field-wide production. The ultimate timing and availability of adequate infrastructure is not within our control and we could experience capacity constraints for extended periods of time that would negatively impact our ability to meet our production targets. Weather, regulatory developments and other factors also affect the adequacy of midstream infrastructure.

We had capital expenditures during 2018 of approximately $174.0 million. We have a capital expenditure budget for 2019 of approximately $94.5 million. Approximately $46.2 million of the 2019 budget is allocated to continue development of our Permian and Delaware Basin assets and $38.3 million for the continued development of our Bakken/Three forks play in North Dakota. The remaining amount is allocated to acquisitions, facilities and other. The 2019 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, our financial results and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the years ended December 31, 2016, 2017 and 2018:

	2016	2017	2018
Total Production (Mboe)	2,262	2,698	3,580
Average daily production (Boepd)	6,181	7,391	9,809
% Oil	61%	58%	64%

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flows 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, 2018, we had approximately $20.0 million of availability under our credit facility. As of March 8, 2019, we had approximately $20.0 million available under our credit facility. 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 March 28, 2019.

Borrowings and Interest. At December 31, 2018, we had a total of $180.0 million outstanding under our credit facility and total indebtedness of $183.4 million (including the current portion). As of March 8, 2019, we had a total of $180.0 million outstanding under our credit facility and total indebtedness of $183.3 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 asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2018, we operated properties comprising approximately 96% of the Boe's of our estimated net proved reserves, 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, 2018, we drilled or participated in 122 gross (60.4 net) wells of which 98% 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 flows from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 63% of our estimated proved reserves on a Boe basis at December 31, 2018 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Results of Operations

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

	Year Ended December 31, (in thousands, except per unit data)		
	2016	2017	2018
Operating revenue[1]:			
Oil sales	$ 50,965	$73,584	$132,904
Gas sales	3,978	6,898	7,854
NGL sales	1,550	5,707	8,272
Other income	62	75	137
Total revenues	$ 56,555	$86,264	$149,167
Operating (loss) income	$(73,878)	$20,886	$ 57,528
Oil sales (MBbls)	1,372	1,574	2,308
Gas sales (MMcf)	3,160	3,889	4,587
NGL sales (MBbls)	363	476	508
Oil equivalents (MBoe)	2,262	2,698	3,580
Average oil sales price (per Bbl)[1]	$ 37.14	$ 46.76	$ 57.59
Average gas sales price (per Mcf)	$ 1.26	$ 1.77	$ 1.71
Average NGL price (per Bbl)	$ 4.27	$ 11.99	$ 16.28
Average oil equivalent sales price (per Boe)	$ 24.97	$ 31.95	$ 41.62

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

Comparison of Year Ended December 31, 2018 to Year Ended December 31, 2017

Revenue. During the year ended December 31, 2018, revenue increased to $149.2 million from $86.3 million in 2017. The increase in revenue was primarily due to higher oil and NGL prices in 2018 as well as higher sales volumes in 2018 for all products as compared to 2017. Higher commodity prices added $26.9 million to revenue, while higher sales volumes contributed $36.0 million to revenue in 2018. During 2018 we experienced an increase in the average realized oil price of approximately 23% from 2017 levels. Average realized gas prices decreased by approximately 3% and average realized NGL prices increased by approximately 36% from 2017 levels. Gas and NGL sales were negatively impacted by pipeline constraints in the Permian and Rocky Mountain regions during 2018.

Oil sales volumes increased to 2,308 MBbls for the year ended December 31, 2018 from 1,574 MBbls for the same period of 2017. The increase in oil sales volumes was due to new production brought on line offset by natural field declines and sales of non-core properties. New production brought on line added 665 MBoe to sales in 2018. Gas sales volumes increased to 4,587 MMcf for the year ended December 31, 2018 from 3,889 MMcf for the year ended December 31, 2017. The increase in gas sales volumes was primarily due to new wells brought on line as well as the acquisition of additional interests in existing wells. New wells brought onto production contributed 574 MMcf to production for the year ended December 31, 2018. NGL sales increased to 508 MBbls for the year ended December 31, 2018 from 476 MBbls for the same period of 2017. The increase in NGL sales was primarily due to increased gas production from fields in West Texas 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, 2018 increased to $24.3 million from $15.2 million in 2017. The increase in LOE was primarily due to higher cost of services and new wells brought onto production during 2018 as well as higher cost incurred shutting in wells for frac protect and repairing wells damaged by frac hits from offset wells. LOE per Boe for the year ended December 31, 2018 was $6.79 compared to $5.63 for the same period of 2017. The increase in LOE per Boe was attributable to higher costs which were somewhat offset by higher sales volumes in 2018 as compared to 2017.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2018 increased to $12.0 million from $7.2 million in 2017. The increase was primarily due to higher realized prices and sales volumes in 2018 as compared to 2017. Production and ad valorem taxes as a percentage of oil and gas revenue remained constant at 8% in 2018 and 2017.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, decreased to $9.7 million for the year ended December 31, 2018 from $13.0 million in 2017. The decrease in 2018 was primarily due to incentive bonuses accrued in 2017 as well as a one-time discretionary bonus paid in 2017. G&A expense per Boe was $2.70 for the year ended December 31, 2018 compared to $4.83 for the same period of 2017. The decrease in per Boe was the result of the decrease in G&A expenses as well as the increase in production in 2018 as compared to 2017.

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 decreased to $2.4 million for the year ended December 31, 2018 compared to $3.2 million for the same period of 2017. The decrease was primarily due stock based compensation relating to stock options being fully amortized prior to 2018.

Depreciation, Depletion, and Amortization ("DD&A") Expenses. DD&A expense excluding accretion, increased to $42.8 million for the year ended December 31, 2018 from $26.2 million in 2017. DD&A expense increased primarily due to higher future development costs included in the December 31, 2018 reserve report, based on current development program, as well as higher production volumes in 2018 as compared to 2017. DD&A per Boe for 2018 was $11.94 compared to $9.72 in 2017. The increase in DD&A expense per Boe was primarily due to a higher full cost pool as well as higher future development costs in 2018 as compared to 2017 and higher capital cost in relation to reserve additions.

Interest Expense. Interest expense increased to $7.1 million in 2018 from $2.5 million for 2017. The increase was primarily due to higher debt levels in 2018 as compared to 2017, as well as higher interest rates in 2018 as compared to 2017. In 2018 the interest rate on our credit facility averaged 5.4% as compared to 4.1% in 2017.

Income Taxes. Due to loss carry forwards, we did not recognize any income tax expense for the years ended December 31, 2018 and 2017.

(Gain) loss on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and by 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 basis differential swaps in 2018 and fixed price swaps and basis differential swaps and collar contracts in 2017. The net estimated value of our commodity derivative contracts was an asset of approximately $15.1 million as of December 31, 2018. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year-ended December 31, 2018, we recognized a gain of $8.1 million, consisting of a loss of $19.0 million on closed contracts and a gain of $27.1 million on the mark to market valuation on open contracts. For the year ended December 31, 2017, we incurred a loss on our derivative contracts of approximately $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million on the mark to market valuation of 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 flows from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2018 and 2017, the net capitalized cost of our oil and gas properties did not exceed the future net revenues from our estimated proved reserves. The year-end amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2018 which were $59.65 per Bbl of oil and $1.76 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves. The twelve month first-day-of-the-month average oil and gas prices for the year ended 2017 were $46.83 per Bbl for oil and $1.79 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

Comparison of Year Ended December 31, 2017 to Year Ended December 31, 2016

Revenue. During the year ended December 31, 2017, revenue increased to $86.3 million from $56.6 million in 2016. The increase in revenue was primarily due to higher commodity prices in 2017 as well as higher sales volumes in 2017 as compared to 2016. Higher commodity prices added $20.8 million to revenue, while higher sales volumes contributed $8.9 million to revenue in 2017. During 2017 we experienced an increase in the average realized oil price of approximately 26% from 2016 levels. Average realized gas prices increased by approximately 41% and average realized NGL prices increased by approximately 181% from 2016 levels.

Oil sales volumes increased to 1,574 MBbls for the year ended December 31, 2017 from 1,372 MBbls for the same period of 2016. The increase in oil sales volumes was due to new production brought on line offset by natural field declines and sales of non-core properties. New production brought on line added 538 MBoe to sales in 2017. Gas sales volumes increased to 3,889 MMcf for the year ended December 31, 2017 from 3,160 MMcf for the year ended December 31, 2016. The increase in gas sales volumes was primarily due to new wells brought on line as well as the acquisition of additional interests in existing wells. New wells brought onto production contributed 601 MMcf to production for the year ended December 31, 2017. NGL sales increased to 476 MBbls for the year ended December 31, 2017 from 363 MBbls for the same period of 2016. The increase in NGL sales was primarily due to increased gas production from fields in West Texas 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, 2017 decreased to $15.2 million from $18.2 million in 2016. The decrease in LOE was primarily due to our focus on lowering LOE and shutting in marginal wells as well as the sale of non-core properties. LOE per Boe for the year ended December 31, 2017 was $5.63 compared to $8.05 for the same period of 2016. The decrease in LOE per Boe was attributable to lower cost as well as higher sales volumes in 2017 as compared to 2016**.**

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2017 increased to $7.2 million from $5.5 million in 2016. The increase was primarily due to higher realized prices and sales volumes in 2017 as compared to 2016. Production and ad valorem taxes as a percentage of oil and gas revenue decreased to 8% in 2017 as compared to 10% in 2016. The decrease in the percentage of oil and gas revenue was primarily due to increased production in Texas which has lower production tax rates than the other states in which we operate.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased to $13.0 million for the year ended December 31, 2017 from $10.4 million in 2016. The increase was primarily due to incentive bonuses accrued in 2017 as well as a one-time discretionary bonus paid in 2017. G&A expense per Boe was $4.83 for the year ended December 31, 2017 compared to $4.58 for the same period of 2016.

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 was consistent at $3.2 million for the years ended December 31, 2017 and 2016. There were no significant grants of stock options or restricted stock in 2017.

Depreciation, Depletion, and Amortization ("DD&A") Expenses. DD&A expense, excluding accretion, increased to $26.2 million for the year ended December 31, 2017 from $24.4 million in 2016. DD&A expense increased primarily due to higher future development costs included in the December 31, 2017 reserve report as well as higher production volumes in 2017 as compared to 2016. DD&A per Boe for 2017 was $9.72 compared to $10.80 in 2016. The decrease in DD&A expense per Boe was primarily due to a higher reserve volumes in 2017 as compared to 2016.

Interest Expense. Interest expense decreased to $2.5 million in 2017 from $3.8 million for 2016. The decrease was primarily due to lower debt levels in 2017 as compared to 2016, partially offset by higher interest rates in 2017 as compared to 2016.

Income Taxes. Due to losses incurred and loss carry forwards, we did not recognize any income tax expense for the years ended December 31, 2017 and 2016.

(Gain) loss on Derivative Contracts. Our derivative contracts consisted of fixed price swaps, basis differential swaps and collar contracts in 2017 and 2016. The net estimated value of our commodity derivative contracts was a liability of approximately $13.2 million as of December 31, 2017. 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, 2017, we incurred a loss on our derivative contracts of approximately $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million on the mark to market valuation of open contracts. For the year-ended December 31, 2016, we incurred a loss of $18.0 million, consisting of a gain of $1.8 million on closed contracts and a loss of $19.8 million related to open contracts.

Monetization of Derivative Contracts. During 2016, we monetized certain of our derivative contracts. Proceeds from the monetization were approximately $14.4 million. We did not monetize any derivative contracts in 2017.

Ceiling Limitation Write-Down. During 2016, we incurred impairments of $67.6 million. As of December 31, 2017, 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 2017 which were $46.83 per Bbl for oil and $1.79 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

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 gathering 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. In addition In January 2019, we announced that we had engaged Petrie Partners to assist us in identifying and assessing our options for our Bakken properties. We are still early in this process and do not know the ultimate outcome. In the event that this process were to result in the sale of our Bakken properties, we believe that the proceeds would be used to significantly pay down or fully retire our debt, support our Raven No. 1 rig in the Delaware Basin until it achieves free cash flow and possibly buy back stock. We feel that the cash flow from these sources will be adequate to fund our operations into the future, long and short term.

Our principal sources of capital are cash flows from operations, borrowings under our credit facility, 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. We believe that our cash flow from these sources going forward, will be adequate to fund our operations

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 increased in 2018, primarily due to increased oil and NGL prices and increased sales volumes for all products during the year ended December 31, 2018 as compared to 2017. We expect cash flows from operations to continue to be a primary source of liquidity in 2019.

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 have entered into NYMEX-based fixed price commodity swap arrangements on approximately 51% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 62% for 2020 and 66% for 2021. Subsequent to December 31, 2018, in connection with the redetermination of our credit facility, we have entered into additional fixed price commodity swaps. Taking these additional contracts into consideration, we have entered into fixed price commodity swap arrangements on approximately 61% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2018) through December 31, 2019, 80% for 2020 and 75% for 2021.

The material terms of our derivative financial instruments as of December 31, 2018 are presented in Note 11 in "Item 8. Financial Statements and Supplementary Data" of this report.

Commodity prices can also affect our operating cash flows 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 flows as the prices paid for services and equipment decline.

Working Capital (Deficit). At December 31, 2018, our current liabilities of $64.4 million exceeded our current assets of $50.7 million resulting in a working capital deficit of $13.7 million. This compares to a working capital deficit of $34.4 million at December 31, 2017. Current assets at December 31, 2018 primarily consisted of cash of $0.9 million, accounts receivable of $39.6 million, current amount of our derivative asset of $9.6 million and other current assets of $0.6 million. Current liabilities at December 31, 2018 primarily consisted of trade payables of $39.6 million, revenues due third parties of $23.1 million, current maturities of long-term debt of $0.3 million, the current amount of our derivative liability of $0.6 million and accrued expenses of $0.8 million. The working capital deficit is expected to be funded by cash flows from operations and borrowings under our credit facility.

Capital Expenditures. Capital expenditures in 2016, 2017 and 2018 were $31.7 million, $135.1 million, and $174.0 million, respectively. Expenditures in 2017 included non-cash expenditures of $26.8 million, (which consisted of 2.0 million shares of our common stock issued in connection with an acquisition in August 2017, all of our interest in the surface estate of Coyanosa Draw Ranch and one-half of the mineral interests under the Coyanosa Draw Ranch). The table below sets forth the components of these capital expenditures:

	Years Ended December 31,		
	2016	2017	2018
		(in thousands)	
Expenditure category:			
Exploration/Development	$30,787	$102,987	$131,271
Acquisitions	—	31,409	41,465
Facilities and other	876	682	1,230
	$31,663	$135,078	$173,966

During 2016 capital expenditures were primarily for exploration and for the development of our existing properties. During 2017 and 2018, capital expenditures were for the exploration and development of our existing properties and acquisition of additional leasehold. Expenditures in 2017 included non-cash expenditures of $26.8 million, (which consisted of 2.0 million shares of our common stock issued in connection with an acquisition in August 2017, all of our interest in the surface estate of Coyanosa Draw Ranch and one-half of the mineral interests under the Coyanosa Draw Ranch). We anticipate making capital expenditures in 2019 of approximately $94.5 million, of which approximately $46.2 million is allocated to acquiring additional acreage and developing our Bone Spring/Wolfcamp acres in the Permian/Delaware Basin. The 2019 budget also allocates approximately $38.3 million for developing our Williston Basin/Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. The 2019 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, our financial results 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 from operations 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 and Uses 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:

	Years Ended December 31,		
	2016	2017	2018
		(in thousands)	
Net cash provided by operating activities	$ 26,872	$ 38,123	$ 80,000
Net cash used in investing activities	(14,071)	(91,053)	(176,204)
Net cash (used in) provided by financing activities	(16,341)	54,548	95,453
	$ (3,540)	$ 1,618	$ (751)

Operating activities for the year ended December 31, 2018 provided $80.0 million in cash, primarily due to higher net income due to higher oil and NGL prices and higher sales volumes for all products. Investing activities used $176.2 million in 2018 primarily for the development of our existing properties and leasehold acquisitions. Cash expenditures for the year ended December 31, 2018 included a decrease in the accounts payable balance related to capital expenditures of $6.0 million, and a decrease in our asset retirement obligation liability of $1.8 million, resulting in actual capital expenditures, net of dispositions, incurred during the period of $168.4 million. Financing activities provided $95.4 million primarily from net borrowings under our credit facility.

Operating activities for the year ended December 31, 2017 provided $38.1 million in cash. Increased net income, due to higher prices and volumes and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $91.1 million primarily for the development of our existing properties. Financing activities provided $54.5 million primarily from the proceeds from the issuance of 28.8 million shares of common stock in January 2017, resulting in net proceeds of $65.2 million, offset primarily by reductions of the amount due under our credit facility.

Operating activities for the year ended December 31, 2016 provided $26.9 million in cash. Net changes in operating assets and liabilities and the monetization of derivative positions accounted for most of these funds. Investing activities used $14.1 million primarily for the development of our existing properties. Financing activities used $16.3 million primarily for reductions of the amount due under our credit facility, offset by long term borrowings and proceeds from the issuance of 28.8 million shares of common stock in May 2016, resulting in net proceeds of $27.1 million.

Future Capital Resources. Our principal sources of capital going forward, for 2019 and beyond, are cash flows from operations, borrowings under our credit facility, proceeds from the sale of properties, monetizing of derivative instruments 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 flows from operations and the amount that we are able to borrow under our credit facility will also decline. As of December 31, 2018 we had availability under our credit facility of $20.0 million 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 March 28, 2019. The risk of not finding commercially productive reservoirs will be compounded by the fact that 63% of our total estimated proved reserves on a Boe basis at December 31, 2018 were classified as undeveloped.

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

- Long-term debt

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2018:

	Payments due in the twelve month periods ended:				
Contractual Obligations (In thousands)	**Total**	**December 31, 2019**	**December 31, 2020-2021**	**December 31, 2022-2023**	**Thereafter**
Long-term debt[1]	$183,358	$ 267	$180,575	$2,516	$—
Interest on long-term debt[2]	26,265	10,960	15,130	175	—
Total	$209,623	$11,227	$195,705	$2,691	$—

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

(2) Interest expense assumes the balances of long-term debt at December 31, and current effective interest rates at that time.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2018, our reserve for these obligations totaled $7.5 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, 2018, 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, 2018, 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:

	2017	2018
	(In thousands)	
Senior secured credit facility	$84,000	$180,000
Real estate lien note	3,616	3,358
	87,616	183,358
Less current maturities	(262)	(267)
Total	$87,354	$183,091

Credit Facility

The Company has 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, 2018, $180.0 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, 2018, the Company had a borrowing base of $200.0 million. The borrowing base is determined semi-annually by the lenders based upon the Company's reserve reports, one of which must be prepared by its 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 the Company's 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 the Company is able to request one redetermination during any six-month period between scheduled redeterminations. Outstanding borrowings in excess of the borrowing base must be repaid immediately or the Company must pledge additional oil and gas properties or other assets as collateral. The Company does not currently have any substantial unpledged assets and it may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause the Company to fail to be in compliance with the financial covenants described below. The Company's borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of its then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. The Company's borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (i) 1.5%-2.5%, depending on the utilization of the borrowing base, or (ii) if we elect, LIBOR plus, in each case, 2.5%-3.5% depending on the utilization of the borrowing base. At December 31, 2018, the interest rate on the credit facility was approximately 6.0% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is May 16, 2021. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the credit facility and is 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 the Company's 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 the Company and its subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of the Company's proven reserves. The Company has also granted its lenders a security interest in our headquarters building.

Under the credit facility, the Company is subject to customary covenants, including certain financial covenants and reporting requirements. The Company is required to maintain a current ratio, as defined in the credit facility, 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. The Company is also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 3.50 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 loss, 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 headquarters building and obligations with respect to surety bonds and derivative contracts.

At December 31, 2018, we were in compliance with the interest coverage ratio and the total debt to EBITDAX ratio and received a waiver with respect to our non- compliance with the current ratio. As of December 31, 2018, the interest coverage ratio was 11.94 to 1.00, the total debt to EBITDAX ratio was 2.14 to 1.00, and our current ratio was 0.96 to 1.00. We have received a waiver for the non-compliance with the current ratio which related only to compliance at December 31, 2018.

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 certain additional covenants including:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and
- if the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

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. As of December 31, 2018, we were in compliance, or have obtained waiver for, all of the terms of our credit facility.

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 was modified on June 20, 2018 to a fixed rate of 4.9% and is payable in monthly installments of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2017, and 2018, $3.6 million and $3.4 million, respectively, were outstanding on the note.

Net Operating Loss Carryforwards

At December 31, 2018, we had, subject to the limitation discussed below, $245.2 million of pre 2018 NOLs for U.S. tax purposes and a $46.8 million NOL for 2018. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018, can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

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 $67.3 million for deferred tax assets at December 31, 2018.

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 2016, 2017 or 2018.

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. Sales of oil and gas properties are treated as a reduction of the full cost pool with no gain or loss being recognized, except under certain circumstances. 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 those of 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 flows 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 oil and gas reserves have been estimated by our engineering and operations departments and assisted by an independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2016, and 2017 and LaRoche Petroleum Consultants as of December 31, 2018. 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, 2016, 2017 and 2018 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 consisted of fixed price swaps, basis differential swaps and collar contracts in 2017. In 2018 our derivative contracts consisted of fixed price swaps and basis differential swaps. 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, 2017, and 2018, the net market value of our commodity derivatives was a net liability of $13.2 million and an asset of $15.1 million, respectively.

New Accounting Standards and Disclosures.

See Note 1, "Organization and Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a discussion of new accounting requirements.

In February 2016, the FASB issued new guidance in ASC 842, *Leases* ("ASC 842"), which will supersede the current guidance in ASC 840, *Leases* ("ASC 840"). The core principle of the new guidance is that a lessee should recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for leases currently classified as operating leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. In January 2018, the FASB issued new guidance in ASC 842 to provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840.

In July 2018, the FASB issued new guidance in ASC 842 to provide entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with ASC 840. An entity that elects this transition method must provide the required ASC 840 disclosures for all periods that continue to be reported in accordance with ASC 840.

The amendments in these ASUs are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption was permitted. The Company expects to adopt ASU 2016-02 retrospectively in the first quarter of 2019 (that is, the initial period of adoption) through a cumulative-effect adjustment to the opening balance of retained earnings. At transition, the Company plans to apply the package of practical expedients provided in ASC 842 that allow companies, among other things, to not reassess contracts that commenced prior to adoption.

The Company has a team, including third-party consultants, to implement the standard and is implementing a software solution that will be used to track and account for its leases under ASC 842 on an ongoing basis. The primary effect on the Company's consolidated financial statements will be to record a right-of-use (ROU) asset and lease liability on the balance sheet for all leases with terms at commencement that are greater than twelve months. Leases will be classified as either finance or operating, with that classification affecting the pattern of expense recognition in the income statement.

The Company enters into certain lease agreements in support of its operations for assets such as compressors, a drilling rig, employee housing and office equipment. As of December 31, 2018, the Company does not anticipate that the adoption and implementation of ASC 842 will result in material changes in assets and liabilities on the consolidated balance sheet in 2019, and will not result in a material impact to the consolidated statement of operations.

The Company has made certain accounting policy decisions including that it plans to adopt the short-term lease recognition exemption, account for certain asset classes and has established a balance sheet recognition capitalization threshold. The Company also expects for certain lessee asset classes to elect the practical expedient to not separate lease and non-lease components. For these asset classes, the agreements will be accounted for as a single component.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flows 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, 2018, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flows by approximately $14.9 million for the year. If commodity prices remain at their current levels the impact on operating revenues and cash flows, 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, 2018, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $15.1 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 recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses.

If oil prices decline by $1.00 per Bbl, then the present value of estimated future net revenues from proved reserves of December 31, 2018 would decline by $18.9 million, or 2.8%. If natural gas prices decline by $0.10 per Mcf, then the present value of estimated future net revenues from proved reserves as of December 31, 2018 would decline by $2.3 million, or 0.3%. However, larger decreases in oil and natural gas prices may have a disproportionate impact on the present value of estimated future net revenues from proved reserves.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of December 31, 2018, we had $180.0 million of outstanding indebtedness under our credit facility with a variable interest rate. At December 31, 2018, the interest rate on the credit facility was approximately 6.0% based on 1-month LIBOR borrowings and level of utilization. An increase in the interest rate of 1% would increase our interest expense by $1.8 million on an annual basis, based on the outstanding balance at December 31, 2018.

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, 2018 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 fourth quarter of 2018 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, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 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 2019 Annual Meeting of Stockholders which appears therein under the caption “Election of Directors – Board of Directors,” “– Code of Ethics,” “– Committees of the Board of Directors.” and Executive Officers.

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 and W. Dean Karrash, as defined by SEC rules, are audit committee financial experts.

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 2018.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2019 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 2019 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 2019 Annual Meeting of Stockholders which appears therein under the captions “Certain Relationships and Related Party 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 2019 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

(a)2. Financial Statement Schedules

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

(a)3. Exhibits

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

Exhibit Number	Description
3.1	Articles of Incorporation of Abraxas dated August 30, 1990. (Filed as Exhibit 3.1 to our Registration Statement on Form S-4, No. 33-36565. (the "S-4 Registration Statement")).
3.2	Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement).
3.3	Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement).
3.4	Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to our Registration Statement on Form S-3, No. 333- 00398).
3.5	Articles of Amendment to the Articles of Incorporation of Abraxas dated as of August 12, 2000. (Filed as Exhibit 3.5 to our Annual Report on Form 10-K filed on April 2, 2001).
3.6	Certificate of Correction dated February 24, 2011 (Filed as Exhibit 3.6 to our Annual Report on Form 10-K filed on March 15, 2012).
3.7	Certificate of Withdrawal dated March 16, 2015. (Filed as Exhibit 3.6 to our Current Report on Form 8-K filed March 17, 2015).
3.8	Certificate of Amendment to Articles of Incorporation dated May 9, 2017. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on May 10, 2017).
3.9	Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on December 18, 2018).
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	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).

Exhibit Number	Description
*10.3	Form of Employment Agreement for Executive Officers (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on December 18, 2018).
*10.5	Amended and Restated Abraxas Petroleum Corporation Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Appendix B to our Proxy Statement filed on April 2, 2015).
*10.6	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).
*10.7	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).
*10.8	Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Appendix A to our Proxy Statement filed on April 3, 2017).
*10.9	Form of Employee Stock Option Agreement under the Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed August 26, 2006).
*10.10	Form of Restricted Stock Agreement under the Amended and Restated Abraxas Petroleum Corporation 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).
*10.11	Form of Restricted Stock Award Agreement under Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on April 6, 2018).
10.13	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 10-Q filed on August 8, 2014.)
10.14	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 10-Q filed on August 8, 2014).
10.15	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 10-Q filed on August 8, 2014).
10.16	Amendment No. 2 to Third Amended and Restated Credit Agreement dated as of April 20, 2016 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender (Previously filed as Exhibit 10.1 to our Current Report on Form 8-K filed on April 20, 2016).
10.17	Amendment No. 3 to Third Amended and Restated Credit Agreement dated as of May 16, 2017 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender. (Previously filed as Exhibit 10.1 to our Current Report on Form 8-K filed on May 17, 2017).
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. (Previously filed as Exhibit 21.1 to our Annual Report on Form 10-K filed on March 15, 2016).
23.1	Consent of BDO USA, LLP. (Filed herewith).
23.2	Consent of LaRoche Petroleum Consultants. (Filed herewith).
23.3	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).

Exhibit Number	Description
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 with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).

* Management Compensatory Plan or Agreement.

Item 16. 10-K Summary

None

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Form 10-K

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation (the "Company") and subsidiaries as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company and subsidiaries at December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018**,** 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) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, 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, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2003.

San Antonio, Texas
March 15, 2019

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control over Financial Reporting

We have audited Abraxas Petroleum Corporation's (the "Company's") internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company and subsidiaries as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 15, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company'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 Annual 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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

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.

/s/ BDO USA, LLP

San Antonio, Texas
March 15, 2019

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31. 2017	December 31. 2018
	(In thousands, except per share/share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 1,618	$ 867
Accounts receivable:		
Joint owners, net	14,218	17,110
Oil and gas production sales	17,789	21,991
Other	86	535
Total accounts receivable	32,093	39,636
Derivative asset—short-term	—	9,602
Other current assets	778	626
Total current assets	34,489	50,731
Property and equipment		
Proved oil and gas properties, full cost method	923,237	1,091,905
Other property and equipment	39,136	39,453
Total	962,373	1,131,358
Less accumulated depreciation, depletion, amortization and impairment	(724,606)	(768,140)
Total property and equipment—net	237,767	363,218
Derivative asset—long term	—	10,527
Deferred financing fees—net	1,285	1,149
Other assets	265	265
Total assets	$ 273,806	$ 425,890

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31.	
	2017	2018
	(In thousands, except per share/share data)	
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 45,570	$ 39,571
Joint interest oil and gas production payable	11,502	23,063
Accrued interest	140	335
Other accrued liabilities	539	511
Derivative liabilities—short-term	10,837	616
Current maturities of long-term debt	262	267
Total current liabilities	68,850	64,363
Long-term debt—less current maturities	87,354	183,091
Other liabilities	132	—
Derivative liabilities long-term	2,387	4,434
Future site restoration	8,775	7,492
Total liabilities	167,498	259,380
Commitments and contingencies (Note 9)		
Stockholders' Equity		
Preferred stock, par value $0.01 per share—authorized 1,000,000 shares; -0- shares issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 400,000,000 shares; 165,889,901 and 166,713,784 issued and outstanding at December 31, 2017 and 2018, respectively	1,659	1,667
Additional paid-in capital	415,471	417,844
Accumulated deficit	(310,822)	(253,001)
Total stockholders' equity	106,308	166,510
Total liabilities and stockholders' equity	$ 273,806	$ 425,890

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2016	2017	2018
	(In thousands, except per share data)		
Revenues:			
Oil	$ 50,965	$ 73,584	$132,904
Gas	3,978	6,898	7,854
Natural gas liquids	1,550	5,707	8,272
Other	62	75	137
Total Revenue	56,555	86,264	149,167
Operating costs and expenses			
Lease operating	18,205	15,197	24,300
Production and ad valorem taxes	5,454	7,228	12,023
Rig expense	664	—	
Depreciation, depletion, amortization and accretion	24,922	26,677	43,275
Proved property impairment	67,626	—	—
General and administrative (including stock-based compensation of $3,194, $3,238 and $2,366, respectively)	13,562	16,276	12,041
Total operating costs and expenses	130,433	65,378	91,639
Operating (loss) income	(73,878)	20,886	57,528
Other (income) expense:			
Interest income	(1)	(1)	(1)
Interest expense	3,828	2,497	7,053
Amortization of deferred financing fees	1,019	423	440
Loss (gain) on derivative contracts	18,028	1,849	(8,060)
Loss (gain) on sale of non-oil and gas assets	(374)	(102)	181
Other	—	214	94
Total other (income) expense	22,500	4,880	(293)
Income (loss) before income tax	(96,378)	16,006	57,821
Income tax (expense) benefit	—	—	—
Net income (loss)	$ (96,378)	$ 16,006	$ 57,821
Net income (loss) per common share—basic	$ (0.79)	$ 0.10	$ 0.35
Net income (loss) per common share—diluted	$ (0.79)	$ 0.10	$ 0.34
Weighted average shares outstanding			
Basic	122,132	161,141	165,635
Diluted	122,132	162,844	167,689

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands except number of shares)

	Common Stock				
	Shares	Amount	Additional Paid in Capital	Accumulated Deficit	Total
Balance at December 31, 2015	106,346,001	$ 1,063	$313,852	$(230,450)	$ 84,465
Net loss	—	—	—	(96,378)	(96,378)
Stock issuance	28,750,000	287	26,848	—	27,135
Stock issued for compensation	41,102	—	40	—	40
Stock-based compensation	—	—	3,194	—	3,194
Stock options exercised	55,716	1	48	—	49
Restricted stock issued, net of forfeitures	(98,802)	—	—	—	—
Balance at December 31, 2016	135,094,017	1,351	343,982	(326,828)	$ 18,505
Net income	—	—	—	16,006	16,006
Stock issuance	28,750,000	288	64,936	—	65,224
Stock issued for acquisition of oil and gas properties	2,000,000	20	3,315	—	3,335
Stock-based compensation	—	—	3,238	—	3,238
Stock options exercised	2,634	—	—	—	—
Restricted stock issued, net of forfeitures	43,250	—	—	—	—
Balance at December 31, 2017	165,889,901	1,659	415,471	(310,822)	106,308
Net income	—	—	—	57,821	57,821
Stock-based compensation	—	—	2,366		2,366
Stock options exercised	150,327	1	13	—	14
Restricted stock issued, net of forfeitures	673,556	7	(6)	—	1
Balance at December 31, 2018	166,713,784	$ 1,667	$417,844	$(253,001)	$166,510

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2016	2017	2018
Operating Activities:			
Net (loss) income	$(96,378)	$ 16,006	$ 57,821
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Loss (gain) on sale of non-oil and gas assets	(374)	(102)	181
Net loss (gain) on derivative contracts	18,028	1,849	(8,060)
Net cash settlements received (paid) on derivative contracts	1,790	2,450	(20,241)
Monetization of derivative contracts	14,370	—	—
Depreciation, depletion and amortization	24,431	26,226	42,759
Proved property impairment	67,626	—	—
Amortization of deferred financing fees	1,019	423	440
Accretion of future site restoration	491	451	516
Stock-based compensation	3,194	3,238	2,366
Non-cash compensation	40	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(4,018)	(18,569)	(7,543)
Other assets	627	155	18
Accounts payable	(3,535)	6,231	11,576
Accrued expenses	(439)	(235)	167
Net cash provided by operating activities	26,872	38,123	80,000
Investing Activities			
Capital expenditures, including purchase and development of properties	(31,663)	(108,236)	(179,509)
Proceeds from the sale of oil and gas properties	13,570	16,979	3,279
Proceeds from the sale of non-oil and gas assets	4,022	204	26
Net cash used in investing activities	(14,071)	(91,053)	(176,204)
Financing Activities			
Proceeds from exercise of stock options and restricted stock	49	—	15
Proceeds from issuance of common stock, net of offering cost of $1.6 million and $3.8 million, respectively	27,135	65,224	—
Proceeds from long-term borrowings	22,000	82,000	127,000
Payments of long-term borrowings	(65,330)	(91,786)	(31,258)
Deferred financing fees	(195)	(890)	(304)
Net cash (used in) provided by financing activities	(16,341)	54,548	95,453
(Decrease) increase in cash and cash equivalents	(3,540)	1,618	(751)
Cash and cash equivalents at beginning of period	3,540	—	1,618
Cash and cash equivalents at end of period	$ —	$ 1,618	$ 867
Supplemental disclosure of cash flow information:			
Interest paid	$ 3,899	$ 2,401	$ 6,858
Income tax paid	$ —	$ —	$ —
Non-cash investing and financing activities			
Change in asset retirement obligation cost and liabilities	$ 285	$ 1,252	$ 1
Properties classified as held for sale	$ 9,685	$ —	$ —
Asset retirement obligations associated with property acquisitions and dispositions, net	$ (1,832)	$ (1,551)	$ (1,799)
Issuance of stock for acquisition of oil and gas properties	$ —	$ 3,335	$ —
Change in capital expenditures included in accounts payable	$ —	$ 23,507	$ (6,014)

See accompanying notes to consolidated financial statements.

1. Organization and Significant Accounting Policies

Nature of Operations

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

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 consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of consolidated financial statements in conformity with 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 most significant estimates pertain to proved oil, gas and NGL 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, the provision for income taxes including uncertain tax positions, stock based compensation, 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.

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, differentials, 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.

Reclassifications

Certain prior year balances have been reclassified for consistency with current year classifications. Such reclassifications had no impact on the results of operations or cash flows from operations.

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 or operating 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 Cash 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 $0.4 million and $0.5 million at December 31, 2017 and 2018, 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, certain direct costs and 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%, 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. The impairment calculations do not consider the impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. During 2016 we recorded a proved property impairment of $67.6 million. As of December 31, 2017 and 2018, our capitalized cost of oil and gas properties did not exceed the future net revenue from our estimated proved reserves.

Other Property and Equipment

Other property and equipment are recorded on the basis of cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and 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 typically in the form of fixed price commodity and basis swaps, 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 over hedged 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, except for derivative instruments, 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, 2016, 2017 and 2018, stock-based compensation was approximately $3.2 million, $3.2 million and $2.4 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 is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period and the capitalized cost is depreciated over the 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 (in thousands) summarizes changes in the Company's future site restoration obligations during the two years ended December 31:

	2017	2018
Beginning future site restoration obligation	$ 8,623	$ 8,775
New wells placed on production and other	1,088	612
Deletions related to property disposals and plugging costs	(1,551)	(2,270)
Accretion expense and other	451	516
Revisions and other	164	(141)
Ending future site restoration obligation	$ 8,775	$ 7,492

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 recognizes oil and gas revenues from its interests in producing wells when control has transferred to the purchaser and to the extent the selling price is reasonably determinable. The Company had no material gas imbalances at December 31, 2017 and 2018.

During 2016, two purchasers accounted for 71% of oil and gas revenues. During 2017 three purchasers accounted for 69% of oil and gas revenues. During 2018, two purchasers accounted for 57% of oil and gas revenues.

Deferred Financing Fees

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

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 $67.3 million for deferred tax assets at December 31, 2018.

On December 22, 2017, the President of the United States signed Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act, among other things, (i) permanently reduces the U.S. federal corporate income tax rate from 35% to 21%, (ii) repeals the corporate alternative minimum tax, (iii) imposes new limitations on the utilization of net operating losses (iv) limits deductibility of interest expense and (v) changes the cost recovery rules. Under U.S. GAAP, the effects of new legislation are recognized upon enactment, which, for federal legislation, is the date the President signs a bill into law. Accordingly, recognition of the tax effects of the Tax Act was required in the interim and annual periods that included December 22, 2017. In December 2017, the SEC issued Staff Accounting Bulletin No. 118 "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" ("SAB 118") which allows a company up to one year to finalize and record the tax effects of the Tax Act and clarifies certain aspects of Accounting Standards Codification 740, "Income Taxes" ("ASC 740") and provides a three-step process for applying ASC 740. The tax effect of the Tax Act, did not have a material impact to the Company's deferred tax position.

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. The Company had no uncertain income tax positions as of December 31, 2018.

New Accounting Standards and Disclosures

In February 2016, the FASB issued new guidance in ASC 842, *Leases* ("ASC 842"), which will supersede the current guidance in ASC 840, *Leases* ("ASC 840"). The core principle of the new guidance is that a lessee should recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for leases currently classified as operating leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. In January 2018, the FASB issued new guidance in ASC 842 to provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840.

In July 2018, the FASB issued new guidance in ASC 842 to provide entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with ASC 840. An entity that elects this transition method must provide the required ASC 840 disclosures for all periods that continue to be reported in accordance with ASC 840.

The amendments in these ASUs are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption was permitted. The Company expects to adopt ASU 2016-02 using a modified retrospective method in the first quarter of 2019 (that is, the initial period of adoption) through a cumulative-effect adjustment to the opening balance of retained earnings. At transition, the Company plans to apply the package of practical expedients provided in ASC 842 that allow companies, among other things, to not reassess contracts that commenced prior to adoption.

The Company has a team, including third-party consultants, to implement the standard and is implementing a software solution that will be used to track and account for its leases under ASC 842 on an ongoing basis. The primary effect on the Company's consolidated financial statements will be to record a right-of-use (ROU) asset and lease liability on the balance sheet for all leases with terms at commencement that are greater than twelve months. Leases will be classified as either finance or operating, with that classification affecting the pattern of expense recognition in the income statement. We anticipate the impact of recording leases as a result of the adoption of this standard to be less than $2.0 million.

The Company enters into certain lease agreements in support of its operations for assets such as compressors, a drilling rig, employee housing and office equipment. As of December 31, 2018, the Company does not anticipate that the adoption and implementation of ASC 842 will result in material changes in assets and liabilities on the consolidated balance sheet in 2019, and will not result in a material impact to the consolidated statement of operations.

The Company has made certain accounting policy decisions including that it plans on adopting the short-term lease recognition exemption, account for certain asset classes and has established a balance sheet recognition capitalization threshold. The Company also expects for certain lessee asset classes to elect the practical expedient to not separate lease and non-lease components. For these asset classes, the agreements will be accounted for as a single component.

2. Impact of ASC 606 Adoption

On January 1, 2018, the Company adopted ASU No. 2014-09, "*Revenue from Contracts with Customers*" ("ASU 2014-09") using the modified retrospective method of transition. Under this method of transition, the Company applied ASU 2014-09 to all new contracts entered into on and after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue attributable to a contract had not been recognized under legacy revenue guidance.

ASU 2014-09 superseded nearly all existing revenue recognition guidance under U.S. GAAP and includes a five step process to recognize revenue when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

For the year ended December 31, 2018, there was no impact to the Company's reported revenues, operating costs and expenses or net income as a result of adopting ASU 2014-09, as compared to legacy revenue guidance. In addition, no cumulative catch-up adjustment to accumulated deficit was required on January 1, 2018 as a result of adopting ASU 2014-09.

3. Revenue from Contracts with Customers

Revenue Recognition

Sales of oil, gas and NGL are recognized at the point in time when control of the product is transferred to the customer and collectability is reasonably assured. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, physical location, quality of the oil or gas, and prevailing supply and demand conditions. As a result, the price of the oil, gas and NGL fluctuates to remain competitive with other available oil, gas and NGL supplies in the market. The Company believes that the pricing provisions of our oil, gas and NGL contracts are customary in the industry.

Oil sales

The Company's oil sales contracts are generally structured such that it sells its oil production to a purchaser at a contractually specified delivery point at or near the wellhead. The crude oil production is priced on the delivery date based upon prevailing index prices less certain deductions related to oil quality, physical location and transportation costs incurred by the purchaser subsequent to delivery. The Company recognizes revenue when control transfers to the purchaser upon delivery at or near the wellhead at the net price received from the purchaser. Payment terms as customarily and normally paid on the twentieth day of the month following production.

Gas and NGL Sales

Under the Company's gas processing contracts, it delivers wet gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. There are no performance obligations related to these contracts. The midstream processing entity processes the gas and remits proceeds to the Company based upon either (i) the resulting sales price of NGL and residue gas received by the midstream processing entity from third party customers or (ii) the prevailing index prices for NGL and residue gas in the month of delivery to the midstream processing entity. Gathering, processing, transportation and other expenses incurred by the midstream processing entity are typically deducted from the proceeds that the Company receives.

In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. With respect to the Company's gas purchase contracts, the Company has concluded that it is the agent, and thus, the midstream processing entity is its customer. Accordingly, the Company recognizes revenue upon delivery to the midstream processing entity based on the net amount of the proceeds received from the midstream processing entity.

Imbalances

The Company had no material gas imbalances at December 31, 2017 and 2018.

Disaggregation of Revenue

The Company is focused on the development of oil and natural gas properties primarily located in the following three operating regions in the United States: (i) the Permian/Delaware Basin, (ii) Rocky Mountain and (iii) South Texas. Revenue attributable to each of those regions is disaggregated in the table below.

	Years Ended December 31,								
	2016			2017			2018		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	(In thousands)								
Operating Region									
Permian/Delaware Basin	$ 3,551	$1,672	$664	$17,722	$3,028	$1,840	$47,175	$2,698	$2,884
Rocky Mountain	$40,048	$1,070	$793	$49,670	$2,694	$3,774	$77,664	$3,913	$5,253
South Texas	$ 7,366	$1,236	$ 93	$ 6,192	$1,176	$ 93	$ 8,065	$1,243	$ 135

Significant Judgments

Principal versus agent

The Company engages in various types of transactions in which midstream entities process the Company's gas and subsequently market resulting NGL and residue gas to third-party customers on behalf of the Company, such as the Company's percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC Topic 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606-10-50-14(a) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under the Company's product sales contracts, the Company is entitled to payment from purchasers once its performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional. The Company records invoiced amounts as "Accounts receivable—Oil and gas production sales" in the accompanying condensed consolidated balance sheet.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as "Accounts receivable - Oil and gas production sales" in the accompanying condensed consolidated balance sheets. In this scenario, payment is also unconditional, as the Company has satisfied its performance obligations through delivery of the relevant product. As a result, the Company has concluded that its product sales do not give rise to contract assets or liabilities under ASU 2014-09. At December 31, 2017 and December 31, 2018, our receivables from contracts with customers were $17.8 million and $22.0 million, respectively.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the midstream purchaser and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil are also estimated.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the year ended December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

4. Acquisitions and Divestitures of Properties

During the year ended December 31, 2018, through multiple transactions, the Company acquired approximately 2,721 net mineral acres of additional leasehold and working interests in its Permian Basin region for an aggregate purchase price of $40.4 million, net of post-closing adjustments. These acquisitions were accounted for as asset acquisitions. Acquisition cost of approximately $21,000 were capitalized in connection with these transactions.

During 2018, the Company divested of various non-core properties for net proceeds of approximately $3.3 million.

5. Long-Term Debt

The following is a description of the Company's debt as of December 31, 2017 and 2018, respectively:

	2017	2018
	(In thousands)	
Senior secured credit facility	$84,000	$180,000
Real estate lien note	3,616	3,358
	87,616	183,358
Less current maturities	(262)	(267)
Total	$87,354	$183,091

Maturities of long-term debt are as follows:

Years ending December 31, (In thousands)	
2019	$ 267
2020	280
2021	180,295
2022	310
2023	2,206
Thereafter	—
Total	$183,358

Credit Facility

The Company has 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, 2018, $180.0 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, 2018, the Company had a borrowing base of $200.0 million. The borrowing base is determined semi-annually by the lenders based upon the Company's reserve reports, one of which must be prepared by its 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 the Company's 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 the Company is able to request one redetermination during any six-month period between scheduled redeterminations. Outstanding borrowings in excess of the borrowing base must be repaid immediately or the Company must pledge additional oil and gas properties or other assets as collateral. The Company does not currently have any substantial unpledged assets and it may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause the Company to fail to be in compliance with the financial covenants described below. The Company's borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of its then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. The Company's borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (i) 1.5%-2.5%, depending on the utilization of the borrowing base, or (ii) if we elect, LIBOR plus, in each case, 2.5%-3.5% depending on the utilization of the borrowing base. At December 31, 2018, the interest rate on the credit facility was approximately 6.0% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is May 16, 2021. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the credit facility and is 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 the Company's subsidiaries has guaranteed the 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 the Company and its subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of the Company's proven reserves. The Company has also granted its lenders a security interest in our headquarters building.

Under the credit facility, the Company is subject to customary covenants, including certain financial covenants and reporting requirements. The Company is required to maintain a current ratio, as defined in the credit facility, 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. The Company is also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 3.50 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 loss, 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 headquarters building and obligations with respect to surety bonds and derivative contracts.

At December 31, 2018, we were in compliance with the interest coverage ratio and the total debt to EBITDAX ratio and received a waiver with respect to our non- compliance with the current ratio. As of December 31, 2018, the interest coverage ratio was 11.94 to 1.00, the total debt to EBITDAX ratio was 2.14 to 1.00, and our current ratio was 0.96 to 1.00. We received a waiver for the non-compliance with the current ratio which related only to compliance at December 31, 2018.

The credit facility contains a number of other 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 certain additional covenants including:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and
- If the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

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. As of December 31, 2018, we were in compliance with, or have obtained a waiver for, all of the terms of our credit facility.

Real Estate Lien Note

The Company has 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 was modified on June 20, 2018 to a fixed rate of 4.9% and is payable in monthly installments of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2017 and 2018, $3.6 million and $3.4 million, respectively, were outstanding on the note.

6. Property and Equipment

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

	Estimated Useful life	December 31, 2017	December 31, 2018
	Years	(In thousands)	
Oil and gas properties	[(1)]	$ 923,237	$1,091,905
Equipment and other	3-39	15,648	15,369
Drilling rig	15	23,488	24,084
		962,373	1,131,358
Accumulated depreciation, depletion, amortization and impairment		(724,606)	(768,140)
Net Property and Equipment		$ 237,767	$ 363,218

(1) Oil and gas properties are amortized utilizing units of production method.

7. Stock-Based Compensation and Option Plans

The Company's Amended and Restated 2005 Employee Long-Term Equity Incentive Plan reserves 12.6 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.

Stock Options

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 2016, 2017 and 2018:

	2016	2017	2018
Weighted average value per option granted during the period	$ 0.68	$1.81	$1.87
Assumptions:			
Forfeiture rate[(1)]	4.2%	2.0%	1.7%
Expected dividend yield[(2)]	0.0%	0.0%	0.0%
Volatility[(3)]	71.1%	67.6%	66.5%
Risk free interest rate[(4)]	1.7%	2.2%	2.9%
Expected life (years)[(5)]	7.0	6.9	7.3
Fair value of options granted (in thousands)	$2,307	$ 574	$ 841

(1) The estimated future forfeiture rate is based on the Company's historical forfeiture rate on similar grants of stock options.
(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 for a period approximating the expected life of the option.
(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:

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Intrinsic value per share
Options outstanding December 31, 2015	6,808	$2.89		
Granted	2,265	1.02		
Exercised	(83)	1.40		
Forfeited/Expired	(836)	2.84		
Options outstanding December 31, 2016	8,154	$2.39		
Granted	317	1.81		
Exercised	(5)	0.97		
Forfeited/Expired	(149)	3.58		
Options outstanding December 31, 2017	8,317	$2.35		
Granted	300	2.80		
Exercised	(379)	1.71		
Forfeited/Expired	(689)	2.70		
Options outstanding December 31, 2018	7,549	$2.37	4.9	$1.68
Exercisable at end of year	6,479	$2.50	4.5	$1.78

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

	2016	2017	2018
Weighted average grant date fair value of stock options granted (per share)	$ 0.68	$ 1.81	$ 1.87
Total fair value of options vested (000's)	$2,776	$2,795	$2,054
Total intrinsic value of options exercised (000's)	$ 39	$ 5	$ 395

As of December 31, 2018, the total compensation cost related to non-vested awards not yet recognized was approximately $0.5 million, which will be recognized in 2019 through 2021. For the years ended December 31, 2016, 2017 and 2018, we recognized $2.0 million, $1.8 million and $1.4 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, 2018:

	Outstanding Options			Exercisable		
Range of stock option prices	**Number Outstanding**	**Weighted average remaining life**	**Weighted average exercise price**	**Number Outstanding**	**Weighted average remaining life**	**Weighted average exercise price**
0.97 – 1.99	3,270,117	4.9	$1.26	2,490,367	4.2	$1.32
2.00 – 2.99	1,422,975	4.4	$2.44	1,319,725	4.0	$2.43
3.00 – 3.99	2,212,606	5.4	$3.29	2,025,106	5.3	$3.30
4.00 – 4.99	544,750	4.2	$4.54	544,750	4.2	$4.54
5.00 – 5.99	98,000	5.4	$5.38	98,000	5.4	$5.38
6.00 – 6.28	1,000	5.5	$6.28	1,000	5.5	$6.28
	7,549,448	4.9	$2.37	6,478,948	4.5	$2.50

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, 2018, the total compensation cost related to non-vested awards not yet recognized was approximately $1.3 million, which will be recognized from 2019 through 2021. For the years ended December 31, 2016, 2017 and 2018, we recognized $1.2 million, $1.4 million and $0.7 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, 2018:

	Number of Shares	**Weighted average grant date fair value**
Unvested December 31, 2015	1,643,284	$3.44
Granted	—	—
Vested/Released	(52,017)	2.40
Forfeited	(98,802)	3.63
Unvested December 31, 2016	1,492,465	$3.47
Granted	44,000	1.75
Vested/Released	(56,340)	3.14
Forfeited	(750)	2.63
Unvested December 31, 2017	1,479,375	$3.43
Granted	861,113	2.17
Vested/Released	(1,326,250)	3.43
Forfeited	(187,557)	3.22
Unvested December 31, 2018	826,681	$2.15

Performance Based Restricted Stock Awards

Effective on April 1, 2018, the Company issued performance-based shares of restricted stock to certain officers and employees under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. The shares will vest in 2021 upon the achievement of performance goals based on the Company's Total Shareholder Return ("TSR") as compared to a peer group of companies. The number of shares which would vest depends upon the rank of the Company's TSR as compared to the peer group at the end of the three-year vesting period, and can range from zero percent of the initial grant up to 200% of the initial grant.

The table below provides a summary of Performance Based Restricted Stock as of the date indicated (shares in thousands):

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2017	—	$ —
Granted	464	2.37
Vested/Released	—	—
Forfeited	(59)	2.37
Unvested December 31, 2018	405	$2.37

Compensation expense associated with the performance based restricted stock is based on the grant date fair value of a single share as determined using a Monte Carlo Simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the performance based restricted stock awards with shares of the Company's common stock, the awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the awards.

As of December 31, 2018, the total compensation cost related to non-vested awards not yet recognized was approximately $0.7 million, which will be recognized from 2019 through 2021. For the year ended December 31, 2018, we recognized $0.2 million, in stock-based compensation expense related to performance based restricted stock awards.

Director Stock Awards

The 2005 Directors Plan (as amended and restated) reserves 2.9 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.

At December 31, 2018, the Company had approximately 10.3 million shares reserved for future issuance for conversion of its stock options, and incentive plans for the Company's directors, employees and consultants.

Common Stock Issuance

In May 2016, we completed a stock offering of 28.8 million shares of common stock for net proceeds of approximately $27.1 million and in January 2017, we completed an offering of 28.8 million shares of common stock for net proceeds of approximately $65.2 million.

8. Income Taxes

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

	As of December 31,		
	2016	2017	2018
	(In thousands)		
Deferred tax liabilities:			
Hedge contracts	$ —	$ —	$ 3,167
Assets held for sale	3,390	—	—
Other	4,431	2,834	2,977
Total deferred tax liabilities	7,821	2,834	6,144
Deferred tax assets:			
Oil and gas properties	48,436	20,011	4,310
Capital loss carryforwards	7,361	3,015	3,980
Depletion carryforward	5,216	3,174	3,098
U.S. net operating loss carryforward	80,670	53,545	61,309
Alternative minimum tax credit	757	757	757
Hedge contracts	3,135	2,777	—
Total deferred tax assets	145,575	83,279	73,454
Valuation allowance for deferred tax assets	(137,754)	(80,445)	(67,310)
Net deferred tax assets	7,821	2,834	6,144
Net deferred tax	$ —	$ —	$ —

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

	Years ended December 31,		
	2016	2017	2018
	(In thousands)		
Current:			
Federal	$—	$—	$—
State	—	—	—
	$—	$—	$—
Deferred:			
Federal	$—	$—	$—
	$—	$—	$—

At December 31, 2018, the Company had, $245.2 million of pre 2018 NOLs for U.S. tax purposes and $46.8 million of 2018 NOLs for U.S. tax purposes. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018, can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

The use of our NOLs 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, 2018, we have not had an ownership change as defined by Section 382. Given historical losses, uncertainties exist as to the future utilization of the NOL carryforwards, therefore, the Company has established a valuation allowance of $137.8 million at December 31, 2016, $80.4 million at December 31, 2017 and $67.3 million at December 31, 2018.

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

	Years Ended December 31,		
	2016	2017	2018
		(In thousands)	
Tax (expense) benefit at U.S. Statutory rates	$ 33,732	$ (5,602)	$(12,142)
(Increase) decrease in deferred tax asset valuation allowance	(34,072)	57,309	13,135
Permanent differences	(1,133)	(1,134)	(500)
Return to provision estimated revision	1,473	2,494	(470)
Change in deferred tax rate	—	(53,125)	—
Other	—	58	(23)
	$ —	$ —	$ —

As of December 31, 2016, 2017 and 2018, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2013 through 2018 remain open to examination by the tax jurisdictions to which the Company is subject.

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act (H.R. 1), was enacted on December 22, 2017. ASC740, *Accounting for Income Taxes*, requires companies to recognize the effect of tax law changes in the period of enactment even though the effective date for most provisions is for tax years beginning after December 31, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance, the reduction in the U.S. corporate income tax rate to 21% did not materially affect the Company's financial statements. Significant provisions that will impact income taxes in future years include: the repeal of the corporate Alternative Minimum Tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

9. Commitments and Contingencies

Operating Leases

The Company leases office space in Dickinson, North Dakota, Lusk, Wyoming and Denver, Colorado. During 2016, 2017 and 2018, rent expense incurred for the Dickinson, North Dakota office was $27,165, $27,840, and $23,200, respectively. The lease expired on October 31, 2018 and was not renewed. Rent expense incurred for the Lusk, Wyoming office for 2016 and 2017 was $9,000 for each year. The lease expired on December 31, 2017 and was not renewed. Rent expense for the Denver Colorado office for 2016 and 2017 was $15,601 and $13,837, respectively. The lease expired on December 31, 2017 and was not renewed.

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, 2018, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

10. Earnings per Share

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

	Years ended December 31,		
	2016	2017	2018
	(in thousands, except per share data)		
Numerator:			
Net income (loss)	$ (96,378)	$ 16,006	$ 57,821
Denominator for basic earnings per share—weighted-average common shares outstanding	122,132	161,141	165,635
Effect of dilutive securities: Stock options, restricted shares and performance based shares	—	1,703	2,054
Denominator for diluted earnings per share—adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	122,132	162,844	167,689
Net (loss) income per common share—basic	$ (0.79)	$ 0.10	$ 0.35
Net (loss) income per common share—diluted	$ (0.79)	$ 0.10	$ 0.34

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, 2016, 1,635 of 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. For the year December 31, 2017 and 2018, 5,018 and 4,007 of 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 options being underwater, respectively

11. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2017 and 2018 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 2017				
Net revenue	$18,802	$ 13,152	$24,722	$29,588
Operating income	$ 4,953	$ 1,260	$ 5,654	$ 9,470
Net income (loss)	$13,690	$ 7,195	$ (770)	$ (4,109)
Net income (loss) per common share—basic	$ 0.09	$ 0.04	$ —	$ (0.02)
Net income (loss) per common share—diluted	$ 0.09	$ 0.04	$ —	$ (0.02)
Year Ended December 31, 2018				
Net revenue	$40,630	$ 30,916	$41,625	$35,996
Operating income	$20,090	$ 10,931	$17,735	$ 8,722
Net income (loss)	$10,779	$(10,554)	$ 1,777	$55,819
Net income (loss) per common share—basic	$ 0.07	$ (0.06)	$ 0.01	$ 0.34
Net income (loss) per common share—diluted	$ 0.06	$ (0.06)	$ 0.01	$ 0.33

12. Benefit Plans

The Company has a defined contribution plan (401(k) plan) covering all eligible employees. In 2016, 2017 and 2018, in accordance with the safe harbor provisions of the plan, the Company contributed $256,309, $330,415 and $331,957, respectively, to the plan. The Company adopted the safe harbor provisions for its 401(k) plan which requires it 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%. Each 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 2016 and 2017 was $18,000 for employees under the age of 50 and $24,000 for employees 50 years of age or older. The employee contribution limit was increased in 2018 to $18,500 for employees under the age of 50 and $24,500 for employees 50 years of age and older.

13. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Our derivative contracts have not been designated 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, 2018

	Oil—WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
January—December 2019	2,941	$56.20
January—December 2020	2,204	$54.35
January—December 2021	1,815	$60.32
Basis Swaps		
January—December 2019	4,000	$ 2.98
January—December 2020	4,000	$ 2.98

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

	Fair Value Derivative Contracts as of December 31, 2017			
	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives—current	$ —	Derivatives—current	$10,837
Commodity price derivatives	Derivatives—long-term	—	Derivatives—long-term	2,387
		$ —		$13,224

	Fair Value Derivative Contracts as of December 31, 2018			
	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives—current	$ 9,602	Derivatives—current	$ 616
Commodity price derivatives	Derivatives—long-term	10,527	Derivatives—long-term	4,434
		$20,129		$ 5,050

Gains and losses from derivative activities are reflected as "(Gain) loss on derivative contracts" in the accompanying Consolidated Statements of Operations. The net estimated value of our commodity derivative contracts was an asset of approximately $15.1 million as of December 31, 2018. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year-ended December 31, 2018, we recognized a gain of $8.1 million, consisting of a loss of $19.0 million on closed contracts and a gain of $27.1 million on the mark to market valuation on open contracts. For the year ended December 31, 2017, we incurred a loss on our derivative contracts of approximately $1.8 million, consisting of a gain of $2.5 million on closed contracts and a loss of $4.3 million on the mark to market valuation of open contracts.

14. 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, 2017 and 2018, 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, 2017
Assets:				
NYMEX fixed price derivative contracts	$—	$ —	$—	$ —
Total Assets	$—	$ —	$—	$ —
Liabilities:				
NYMEX fixed price derivative contracts	$—	$13,208	$—	$13,208
NYMEX basis differential swap		—	16	16
Total Liabilities	$—	$13,208	$ 16	$13,224

	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, 2018
Assets:				
NYMEX fixed price derivative contracts	$—	$18,172	$ —	$18,172
NYMEX basis differential swap	—	—	1,957	1,957
Total Assets	$—	$18,172	$1,957	$20,129
Liabilities:				
NYMEX fixed price derivative contracts	$—	$ —	$ —	$ —
NYMEX basis differential swap	—	—	5,050	5,050
Total Liabilities	$—	$ —	$5,050	$ 5,050

The Company's derivative contracts at December 31, 2018 consisted of NYMEX-based fixed price commodity swaps and basis differential swaps. The NYMEX- based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, we enter the various inputs into a model and compare our results to the third party for reasonableness. The fair value of the basis swaps 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, 2018.

	(In thousands)
Unobservable inputs at January 1, 2018	$ (16)
Changes in market value	$(3,093)
Settlements during the period	$ 16
Unobservable inputs at December 31, 2018	$(3,093)

There were no transfers from level 3 in 2018.

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

15. Subsequent Events

In March 2019, the Company entered into the following derivative contracts:

	Oil—WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
July—December 2019	1,156	$58.50
January—December 2020	819	$57.65
January—December 2021	236	$55.70

16. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying tables (in thousands) presents information concerning the Company's oil and gas producing activities "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows as of December 31:

	Years Ended December 31,	
	2017	2018
Proved oil and gas properties	$ 923,237	$1,091,905
Unproved properties	—	—
Total	923,237	1,091,905
Accumulated depreciation, depletion, amortization and impairment	(706,537)	(748,773)
Net capitalized costs	$ 216,700	$ 343,132

Cost incurred in oil and gas property acquisition and development activities were as follows for the years ended December 31 (in thousands):

	2016	2017	2018
Development costs	$18,262	$ 94,478	$131,271
Exploration costs	12,529	8,509	—
Property acquisition costs	—	31,409	41,465
	$30,791	$134,396	$172,736

Results of operations from oil and gas producing activities were as follows for the years ended December 31:

	2016	2017	2018
Revenues	$ 56,493	$ 86,189	$149,030
Production costs	(23,659)	(22,425)	(36,323)
Depreciation, depletion and amortization	(22,803)	(25,676)	(42,237)
Proved property impairment	(67,626)	—	—
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$(57,595)	$ 38,088	$ 70,470
Depletion rate per barrel of oil equivalent	$ 10.08	$ 9.52	$ 11.80

Estimated Quantities of Proved Oil and Gas Reserves

Reserve estimates are inherently imprecise and 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.

The following set forth changes in estimated net proved reserves for the years ended December 31, 2016, 2017 and 2018.

	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Oil Equivalents (Mboe)
Change in Proved Reserves				
Balance at December 31, 2015	24,131	6,556	75,027	43,190
Revisions of previous estimates	1,379	2,300	(1,537)	3,424
Extensions and discoveries	1,183	157	1,179	1,537
Sales of minerals in place	(1,112)	(6)	(680)	(1,232)
Production	(1,372)	(363)	(3,160)	(2,262)
Balance at December 31, 2016	24,209	8,644	70,829	44,657
Revisions of previous estimates	259	1,269	19,311	4,747
Extensions and discoveries	14,533	2,813	14,534	19,768
Purchases of minerals in place	8	14	1,001	189
Sales of minerals in place	(364)	(289)	(3,958)	(1,312)
Production	(1,574)	(476)	(3,889)	(2,698)
Balance at December 31, 2017	37,071	11,975	97,828	65,351
Revisions of previous estimates	(4,206)	(1,927)	(2,618)	(6,570)
Extensions and discoveries	11,270	1,797	11,475	14,979
Purchases of minerals in place	688	—	1,137	877
Sales of minerals in place	(278)	(1,303)	(13,491)	(3,829)
Production	(2,308)	(508)	(4,587)	(3,580)
Balance at December 31, 2018	42,237	10,034	89,744	67,228

The following is a summary of the changes to the Company's proved reserves that occurred during 2018:

Revisions to prior estimates:

There was a decrease of 45 MBoe of net reserves attributable to changes in projections for the Company's producing wells based on actual performance during 2018. The Company also converted thirteen proved undeveloped Three Fork 2nd bench locations in McKenzie County, North Dakota, to probable undeveloped reserves during 2018, accounting for 6,525 MBoe of net reserves. These locations are no longer included in the Company's five-year development plan.

Extensions, discoveries and other additions:

The Company added nineteen new proved undeveloped operated locations accounting for 8,130 MBoe of net reserves along with two proved undeveloped non- operated locations accounting for 838 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing wells or producing wells operated by others. The Company also converted two probable undeveloped locations to producing reserves accounting for 1,523 MBoe of net reserves. The Company also converted five probable undeveloped locations to proved undeveloped reserves accounting for 2,670 MBoe of net reserves. In the Bakken/Three Forks system in McKenzie County, North Dakota, during 2018 the Company added three new proved undeveloped locations attributable to unit line well configurations accounting for 1,692 MBoe of net reserves. The Company also added six new non-operated proved non-producing locations accounting for 126 MBoe of net reserves.

Purchases:

In the Wolfcamp/3rd Bone Spring system in Ward, County, Texas, during 2018 the Company acquired four new producing wells accounting for 877 MBoe of net producing reserves.

Sales:

The Company sold substantially all its holdings in the Ira Area accounting for 203 MBoe of net proved reserves. The Company also sold one producing and two proved undeveloped Delaware locations in Ward County, Texas, accounting for 3,558 MBoe of net reserves. Other miscellaneous asset sales during the year accounted for 68 MBoe of net reserves.

Production:

The Company produced 3,580 MBoe of net reserves during 2018.

The following is a summary of the changes to the Company's proved reserves that occurred during 2017:

Revisions to prior estimates:

There was an increase of 621 MBoe of net reserves attributable to changes in projections for the Company's producing wells based on actual performance during 2017. Most of this increase was attributable to the Company's Wolfcamp producing wells in Ward County, Texas. There was also an increase of 1,951 net MBoe attributable to increases in projections for the Company's Wolfcamp PUDs in Ward County. These increases were based on the over-performance of the Company's existing Wolfcamp producing wells as mentioned above. There was also an increase in this category of 2,698 MBoe attributable to increased economic life calculations at the higher commodity pricing experienced during 2017. There were also seven miscellaneous cases in this category that were removed from the report due to the fact that the Company no longer intends to develop them within the five-year allowance. These cases accounted for 523 MBoe of net reserves.

Extensions, discoveries and other additions:

The Company added three new Wolfcamp producing wells in Ward, County, Texas accounting for 1,229 MBoe of net producing reserves. The Company also converted three probable undeveloped Wolfcamp A locations in Ward County, TX, to proved producing reserves during 2017 accounting for 2,028 MBoe of net reserves. The Company also added 27 proved undeveloped Wolfcamp A locations, four Third Bone Spring locations, and two Wolfcamp B locations in Ward County, Texas, accounting for 11,928 MBoe of net reserves. These locations are direct offsets to either successful Abraxas producing wells or producing wells operated by others. The Company also converted ten probable undeveloped Wolfcamp A locations in Ward County, Texas, to proved undeveloped reserves during 2017 accounting for 4,343 MBoe of net reserves. The Company also developed a new Eagle Ford well in Atascosa County, Texas, accounting for 240 MBoe of net reserves.

Purchases:

The company purchased wells and acquired additional interest in existing wells which added 189 MBoe of net reserves.

Sales:

The Company sold substantially all of its holdings in the Powder River Basin of Wyoming during 2017. These sales accounted for the decrease of 1,312 MBoe of net proved reserves.

Production:

The Company produced 2,698 MBoe of net reserves during 2017.

The following is a summary of the changes to the Company's proved reserves that occurred during 2016:

Revisions to prior estimates:

An increase of 5,005 MBoe of reserves was attributable to the Company's Bakken and Three Forks proved undeveloped locations in McKenzie County, North Dakota, due to continuing improvement in its producing well production results. Well results improved as a result of the application of optimized completion methods. Similarly, reserves for the Company's Bakken and Three Forks producing wells increased by 1,360 MBoe of net producing reserves due to improved performance. Projections for the Hedgehog State 16-2H producing well and its two related proved undeveloped locations in the Porcupine Field, Campbell County, Wyoming, decreased by 670 MBoe of net reserves due to the under-performance of the Hedgehog State 16-2H. There was also a reduction in this category of 2,271 MBoe attributable to shortened economic life calculations at the lower commodity pricing.

Extensions, discoveries and other additions:

The Company added the Caprito 99 302H as a new Wolfcamp producing well in Ward County, Texas, accounting for 449 MBoe of net producing reserves. It also added five new proved undeveloped Wolfcamp locations offsetting this new producer accounting for 805 MBoe of net undeveloped reserves. The Company also developed a new Austin Chalk producer in Atascosa County, Texas, which accounted for 265 MBoe of net producing reserves. Further, the Company added eight new proved undeveloped Bakken/Three Forks locations on non-operated units in McKenzie County, North Dakota, accounting for 18 MBoe of net undeveloped reserves. These locations were added in response to operator well proposals.

Sales:

The Company sold all its holdings in the Portilla Field in San Patricio County, Texas, and in the Brooks Draw Field in Converse County, Wyoming, during 2016. These sales accounted for 1,232 MBoe of net proved reserves.

Production:

The Company produced 2,262 MBoe of net reserves during 2016.

The following table presents the Company's estimate of its net proved developed and undeveloped oil and gas reserves as of December 31, 2016, 2017 and 2018:

	Total			
	OIl (MBbl)	**NGL (MBbl)**	**Gas (MMcf)**	**Oil Equilavents (Mboe)**
Proved Developed Reserves:				
December 31, 2016	7,818	2,568	27,792	15,018
December 31, 2017	10,820	3,794	39,974	21,720
December 31, 2018	13,586	3,804	43,271	24,602
Proved Undeveloped Reserves:				
December 31, 2016	16,391	6,076	43,037	29,639
December 31, 2017	25,808	8,181	57,854	43,631
December 31, 2018	28,651	6,230	46,473	42,626

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, 2016, and 2017 and LaRoche Petroleum Consultants as of December 31, 2018, assisted by the engineering and operations departments of the Company.

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 2016, 2017, and 2018, 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 LaRoche Petroleum Consultants 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. LaRoche Petroleum Consultants 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 LaRoche Petroleum Consultants were developed utilizing studies performed by LaRoche Petroleum Consultants and assisted by the Engineering and Operations departments of Abraxas. Reserves are estimated by independent petroleum engineers. The report of LaRoche Petroleum Consultants dated February 12 2019, contains further discussions of the reserve estimates and evaluations prepared by LaRoche Petroleum Consultants as well as the qualifications of LaRoche Petroleum Consultants'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, 2016, 2017 and 2018 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 40 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, 2016, 2017 and 2018 (in thousands):

	Years Ended December 31,		
	2016	2017	2018
Future cash inflows	$ 999,716	$2,035,619	$2,876,976
Future production costs	(357,917)	(609,921)	(849,063)
Future development costs	(267,836)	(461,619)	(547,163)
Future income tax expense (1)	—	(83,915)	(181,224)
Future net cash flows	373,963	880,164	1,299,526
Discount	$(213,363)	$ (474,423)	$ (647,642)
Standardized Measure of discounted future net cash relating to proved reserves	$ 160,600	$ 405,741	$ 651,884

(1) There was no provision for future income tax expense for the year ended December 31, 2016 due to net operating loss carryovers.

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 for the periods indicated (in thousands):

	Years Ended December 31,		
	2016	2017	2018
Standardized Measure, beginning of year	$197,251	$160,600	$ 405,741
Sales and transfers of oil and gas produced, net of production costs	(32,834)	(63,764)	(112,707)
Net change in prices and development and production costs from prior year	(58,425)	159,661	268,942
Extensions, discoveries, and improved recovery, less related costs	5,531	129,277	153,544
Sales of minerals in place	(4,433)	(8,583)	(39,253)
Purchases of minerals in place	—	1,238	8,990
Revisions of previous estimates	12,317	31,044	(67,345)
Change in timing and other	21,468	1,908	30,811
Change in future income tax expense	—	(21,700)	(37,413)
Accretion of discount	19,725	16,060	40,574
Standardized Measure, end of year	$160,600	$405,741	$ 651,884

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

	Years Ended December 31,		
	2016	2017	2018
Oil (per Bbl) (1)	$42.74	$51.34	$65.56
Gas (per MMbtu) (2)	$ 2.50	$ 2.99	$ 3.05
Oil (per Bbl) (3)	$35.54	$46.83	$56.95
Gas (per MMbtu) (4)	$ 1.41	$ 1.79	$ 1.76
NGL's (per Bbl) (5)	$ 5.17	$13.19	$19.95

(1) The quoted oil price for the year ended December 31 of each year, 2016, 2017 and 2018 is the 12-month unweighted average first-day-of-the-month West Texas Intermediate spot price for each month of 2016, 2017 and 2018.

(2) The quoted gas price for the year ended December 31, 2016, 2017 and 2018 is the 12-month unweighted average first-day-of-the-month Henry Hub spot price for each month of 2016, 2017 and 2018.

(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

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

23.2 Consent of LaRoche Petroleum Consultants. (Filed herewith).

23.3 Consent of DeGoyler 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 LaRoche Petroleum Consultants with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).

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* Management Compensatory Plan or Agreement.

SIGNATURES

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

ABRAXAS PETROLEUM CORPORATION

By: /s/ Robert L.G. Watson	By: /s/ Steven P. Harris	By: /s/ G. William Krog, Jr.
President and Principal Executive Officer	Vice President and Chief Financial Officer Principal Financial Officer	Vice President and Chief Accounting Officer Principal Accounting Officer

DATED: March 15, 2019

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

Signature	Name and Title	Date
/s/ Robert L.G. Watson Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	March 15, 2019
/s/ Steven P. Harris Steven P. Harris	Vice President, CFO (Principal Financial Officer)	March 15, 2019
/s/ G. William Krog, Jr. G. William Krog, Jr.	Vice President, Chief Accounting Officer (Principal Accounting Officer)	March 15, 2019
/s/ Harold D. Carter Harold D. Carter	Director	March 15, 2019
/s/ Ralph F. Cox Ralph F. Cox	Director	March 15, 2019
/s/ W. Dean Karrash W. Dean Karrash	Director	March 15, 2019
/s/ Jerry J. Langdon Jerry J. Langdon	Director	March 15, 2019
/s/ Dennis E. Logue Dennis E. Logue	Director	March 15, 2019
/s/ Brian L. Melton Brian L. Melton	Director	March 15, 2019
/s/ Paul A. Powell, Jr. Paul A. Powell, Jr.	Director	March 15, 2019
/s/ Edward P. Russell Edward P. Russell	Director	March 15, 2019

CORPORATE INFORMATION

Corporate Office
18803 Meisner Drive
San Antonio, Texas 78258
Phone: 210.490.4788

Legal Counsel
Jackson Walker L.L.P.
San Antonio, Texas

Independent Public Accountants
BDO USA, LLP
San Antonio, Texas

Independent Reservoir Engineers
LaRoche Petroleum Consultants, LTD.
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 7, 2019 at 9:00 a.m. CT
Abraxas Petroleum Corporation
San Antonio, Texas

OFFICERS

Robert L.G. Watson
President / Chief Executive Officer

Steven P. Harris
Vice President / Chief Financial Officer

Peter A. Bommer
Vice President—Engineering

Tod A. Clarke
Vice President—Land

G. William Krog, Jr.
Vice President—Chief Accounting Officer

Dirk A. Schwartz
Vice President—Business Development

Kenneth W. Johnson
Vice President—Operations

Stephen T. Wendel
Vice President—Marketing & Contracts

DIRECTORS

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

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

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

W. Dean Karrash[1]
President / Chief Financial Officer,
Burke, Lawton, Brewer & Burke, LLC
Ambler, Pennsylvania

Jerry J. Langdon[1]
Private Investor
Houston, TX

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

Brian L. Melton[1]
Chief Commercial Officer
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

Web Address
www.abraxaspetroleum.com

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