ABRAXAS PETROLEUM CORP
Form 10-K
March 13, 2015

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2014

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

Commission File Number 001-16071

ABRAXAS PETROLEUM CORPORATION
(Exact name of Registrant as specified in its charter)

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

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

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

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

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

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act.Yes No ý

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

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 ýNo

Indicate by check mark if the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ýNo

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 x 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 x
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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

As of June 30, 2014, 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 $604,088,667 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 10, 2015, there were 106,191,078 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2015 Annual Meeting of Stockholders to be held on May 5, 2015.	Part III

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

- the availability of capital;
- the prices we receive for our production and the effectiveness of our hedging activities;
- our success in development, exploitation and exploration activities;
- our ability to procure services and equipment for our drilling and completion activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- our restrictive debt covenants;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- other factors discussed elsewhere in this report

GLOSSARY OF TERMS

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

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

Terms used to describe quantities of oil and gas:

“Bbl” – barrel or barrels.

“Bcf” – billion cubic feet of gas.

“Bcfe” – billion cubic feet of gas equivalent.

“Boe” – barrels of oil equivalent.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

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“Mcfe” – thousand cubic feet of gas equivalent.

“MMBbl” – million barrels.

“MMBoe” – million barrels of oil equivalent.

“MMBtu” – million British Thermal Units of gas.

“MMcf” – million cubic feet of gas.

“MMcfe” – million cubic feet of gas equivalent.

“NGL” – natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

“Developed acreage” means acreage which consists of leased acres spaced or assignable to productive wells.

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

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

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

“Gross acres” are the number of acres in which we own a working interest.

“Gross well” is a well in which we own an interest.

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

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

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

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

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

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

“Proved reserves*” Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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

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

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

“Undeveloped oil and gas reserves*"” Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see:
http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.21

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Part I

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

Item 1. Business

General

On October 31, 2014 we closed on the sale of our interest in Canadian Abraxas Petroleum, ULC (" Canadian Abraxas"), an indirect wholly-owned Canadian subsidiary of Abraxas Petroleum Corporation. As a result of the disposal of Canadian Abraxas, the results of operations of Canadian Abraxas are reflected in our Financial Statements and in this report as “Discontinued Operations” and our remaining operations are referred to in our Financial Statements and in this report as “continuing Operations” or “continued Operations.” Unless otherwise noted, all disclosures are for continuing operations.
We are an independent energy company primarily engaged in the acquisition, exploration, development and production of oil and gas. At December 31, 2014, our estimated net proved reserves were 42.4 MMBoe, of which 42% were classified as proved developed, 78% were oil and NGL and 92% of which (on a PV-10 basis) were operated by us. Our daily net production for the year ended December 31, 2014 was 5,720 Boepd, of which 77% was oil or liquids.

Our oil and gas assets are located in three operating regions, the Rocky Mountain, Permian Basin and onshore Gulf Coast. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2014:

				Estimated Net Proved Reserves		Net Production	
	Gross Producing Wells	Average Working Interest	Total Net Acres	(MBoe)	% Oil/NGL	(MBoe)	% Oil/NGL
Rocky Mountain	788	11.28 %	43,855	23,304	82.3 %	1,088.0	83.8 %
Permian Basin	236	65.39 %	30,891	5,100	42.6 %	333.1	49.8 %
Onshore Gulf Coast	77	85.71 %	13,577	14,002	83.8 %	666.5	78.8 %
Total United States	1,101	29.22 %	88,323	42,406	78.1 %	2,087.6	76.7 %

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

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

Our properties in the onshore Gulf Coast region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas, the Eagle Ford shale in Atascosa and McMullen Counties, Texas and in the Portilla field in San Patricio County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation at a depth of 14,000 feet. In the Eagle Ford, our wells produce from the Eagle Ford shale from 8,000 to 11,000 feet, and in the Portilla field, our wells produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.

Strategy

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

Focusing our capital and resources on our core operated basins. Our core basins consist of the Williston Basin (Bakken/Three Forks), onshore Gulf Coast (Eagle Ford shale), which primarily produce oil and liquids, and the Permian Basin and Powder River Basin, which primarily produce gas. Given the disparity which has existed during the past several years and which continues currently between oil and gas prices, the economics of drilling oil wells is far superior to drilling gas wells. Thus, substantially all of our 2015 estimated capital expenditures will be in our two primary oil basins drilling Bakken, Three Forks and Eagle Ford oil wells. The remainder of our capital will be spent on leasehold acquisitions in these core basins. As part of our efforts to focus our property portfolio, we are continually marketing assets we have deemed non-core. These include assets with a low working interest that are non-operated and/or that fall outside of our four core basins. Any proceeds from these asset sales will be used to reduce our indebtedness and/or redeployed into our core operating basins.

Maintaining financial flexibility. Our primary sources of capital are availability under our credit facility and cash flow from operations. At December 31, 2014 we had approximately $95.0 million of availability under our credit facility and for the year ended December 31, 2014, we generated approximately $94.5 million of cash flow from operations. We seek to reduce the volatility of our cash flow from operations by hedging a portion of our production . We also plan on deploying our available capital in a cost-effective manner. For example, we exclusively utilize PAD development drilling with our drilling rig in the Williston Basin and we seek to operate a high percentage of our properties which allows us to better control costs. At December 31, 2014, we operated properties comprising 92% of our proved developed reserves on a PV-10 basis.

Profitably grow production and reserves. We have a substantial low-decline legacy production base as evidenced by our over 21 year reserve life as of year-end 2014. Our capital is currently being deployed largely into unconventional oil assets with relatively predictable production profiles, yet steep initial decline rates. Therefore, the economics of these oil wells are highly dependent on both near term commodity prices and strong operational cost control. Cost savings achieved through efficiencies of using our rig in the Williston Basin, and heightened focus on cost control in all of our operated positions both contribute to our history of adding low cost barrels to our production base. As evidence of production growth not being an objective, but rather the outcome of sound investment decisions, we achieved 242% oil growth and 68% total volume growth since the first quarter of 2010.

2015 Budget and Drilling Activities

Our capital expenditure budget for 2015 is $54.0 million. Substantially all of the 2015 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks in the Rocky Mountain region and in the Eagle Ford Shale play in South Texas. The 2015 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other petroleum producing countries, the actions of the Organization of

Petroleum Exporting Countries, domestic regulation, legislation and policies. Decreases in the prices we receive for our oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, our revenue, profitability and cash flow from operations. Refer to "Risk Factors – Risks Relating to Our Industry — Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies" for more information relating to the effects 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. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Hedging Arrangements" and Note 12 of the notes to our consolidated financial statements for more information regarding our derivative activities.

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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, 2014, two purchasers of production accounted for approximately 62% of our oil and gas sales. During the year ended December 31, 2013, two purchasers of production accounted for approximately 49% 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 2012 to 2014.

Regulation of Oil and Gas Activities

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

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

Development and Production

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

- the location of wells;
- the method of drilling and casing wells;
- the 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.

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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 natural 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

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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 for FERC’s NGA jurisdiction. From time to time, FERC reconsiders its test for defining non-jurisdictional gathering. FERC has also permitted jurisdictional pipelines to “spin down” exempt gathering facilities into affiliated entities that are not subject to FERC jurisdiction, although FERC continues to examine the circumstances in which such a “spin down” is appropriate and whether it should reassert jurisdiction over certain gathering companies and facilities that previously had been “spun down.” We cannot predict the effect that FERC’s activities in this regard may have on the operations of our properties, but we do not expect these activities to affect the operations in any way that is materially different from the effect thereof on our competitors.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service requirements, but does not generally entail rate regulation. In the United States, gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under FERC Order 636. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the state’s more active review of rates, services and practices associated with the gathering and transportation of gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

Regulation of Transportation of Oil in the United States

Sales of oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, FERC, in February 2003, increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulations, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines’ published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

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

In response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. Recently, in response to train derailments occurring in 2013, U.S. regulators are 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) to develop 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) to audit 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

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product is properly tested and classed and to assure all shipments by rail of oil be handled as a Packing Group I or II hazardous material.

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

Environmental Matters

Oil and gas operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, storage and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences;
- require protective measures to prevent drilling fluids from coming into contact with ground water;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, and gas processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and areas inhabited by threatened or endangered species and other protected areas;
- require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells;
- require disclosure of chemicals injected into wells in conjunction with hydraulic fracturing operations;
- restrict injection of liquids into subsurface strata that may contaminate groundwater; and
- impose substantial penalties for violations of environmental rules or pollution resulting from our operations.

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

We are not currently involved in any administrative, judicial or legal proceedings arising under federal, state, 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 owner or operator of a disposal site or sites where a release occurred and companies that arranged for the disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment.

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

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

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

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

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

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

Safe Drinking Water Act. Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act, which we refer to as the SDWA, and analogous state and local laws. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production. The main goal of the SDWA is the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In most states, no underground injection may take place except as authorized by permit or rule. In addition, subsurface injection of water or other produced fluids from drilling or hydraulic fracturing processes have come under increased public and governmental scrutiny. Some jurisdictions, Texas for example, have adopted new rules for injection wells aimed at reducing the potential for earthquakes associated with injection activities. We currently own and operate various underground injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. In the past few years, EPA has adopted new more restrictive regulations governing air emissions from oil and gas operations, including regulations which impose new restrictions on volatile organic compounds, sulfur dioxide and hazardous air pollutants. Certain of these regulations became effective in 2014, with the majority of regulatory requirements imposing new restrictions on air emissions arising from hydraulic fracturing operations in 2015.

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

Hydraulic Fracturing. Most of our current operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand, or other proppants, into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate the formation to enhance production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills such as the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act have been introduced in Congress to subject hydraulic fracturing to federal regulation under laws such as the Safe Drinking Water Act. If adopted, these bills could result in additional chemical disclosure and permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, these bills would require the public disclosure of information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. The EPA has finalized its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, which is expected to result in a final report on the subject with recommendations in early 2015. Also, the U.S. Department of the Interior, Bureau of Land Management ("BLM") is expected to finalize proposed regulations, in 2015, concerning hydraulic fracturing on federal and tribal lands, including chemical disclosure. In addition to these federal legislative and regulatory proposals, some states and local governments have considered imposing, or have adopted various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact water available for hydraulic fracturing. If these types of conditions are widely adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells. Some states in which we operate have implemented disclosure requirements for chemicals used in hydraulic fracturing. Additional information concerning hydraulic fracturing is included under Item 1A. related to risk factors.

Climate change legislation and greenhouse gas regulation. Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. As a result of the U.S. Supreme Court decision in Massachusetts, et al. v. EPA, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, the EPA has issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. These regulations may apply to our operations. The EPA has adopted other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and gas exploration and production industry and the pipeline industry. Moreover, in January 2015, the Obama Administration announced that it would directly regulate methane emissions from the oil and gas industry as part of its climate strategy. Additional rules from the EPA, BLM, and Department of Energy are expected under this methane plan. Although the announcement gave no details on the upcoming regulations, it warned that the oil and gas sector will need to reduce its methane emissions by 40 to 50 percent from 2012 emission levels by 2025. The EPA's finding, the greenhouse gas reporting rule, the methane plan and the other rules to regulate the emissions of greenhouse gases may affect the cost of our operations and also affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Although various climate change legislative measures have been under consideration by the U.S. Congress, it is not possible at this time to predict when, or if, Congress will act on climate change legislation. Finally, some states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular jurisdiction of our operations, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations. Additional information concerning climate change is included under Item 1A. related to risk factors.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. If we were to conduct any exploration and production activities on federal lands in the future, those activities would need to obtain governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and gas projects.

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Endangered Species Act. The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our properties may be located in areas that may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. Looking forward, we expect more listings of such species to occur, in light of consent decrees involving the U.S. Fish and Wildlife Service which require the agency to decide whether or not to list, as endangered or threatened, approximately 251 candidate species by 2016. Included in this group are a number of terrestrial species, such as the lesser prairie chicken which, if listed, could include habitat in areas where we operate or plan to operate. Such listing of additional species, or the discovery of previously unidentified endangered or threatened species, could cause us to incur additional costs or become subject to operating restrictions, construction delays, or bans on operating in the affected areas.

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

Title to Properties

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

Competition

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

Employees

As of March 10, 2015, we had 123 full-time employees. We retain independent geological, land, marketing and engineering consultants from time to time and expect to continue to do so in the future.

Available Information

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

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

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Item 1A. Risk Factors

Risks Related to Our Business

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

Prices for oil and gas (including prices for NGL and condensate) fluctuate widely. For example, during 2014, daily settlement prices for New York Mercantile Exchange (NYMEX) for West Texas Intermediate prices ranged from a high of $107.26 per Bbl to a low of $53.27 per Bbl and NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu. Among the factors that can or could cause these price fluctuations are:

- 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 and refining facilities;
- worldwide economic and political conditions, including political instability or armed conflict in oil and gas producing regions;
- 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;

Our cash flows and results of operations depend to a great extent on the prevailing prices for oil and gas. Prolonged or substantial declines in oil and/or gas prices may 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.
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 may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance capital expenditures. Additionally, if we expect or 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 flow from operations, borrowings under credit facilities, sales of producing properties, and sales of debt and equity securities and we expect to continue to do so in the future. We cannot assure you that we will have sufficient capital resources in the future to finance all of our planned capital expenditures.

Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flow from operations. Lower prices and/or lower production could also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If

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our cash flow from operations does not increase as a result of planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

The borrowing base under our credit facility is determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under our credit facility to meet our capital requirements and/or trigger certain repayment obligations. Such a reduction could be the result of lower commodity prices and/or production, an inability to drill or unfavorable drilling results, changes in oil and gas reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

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

We have sold producing properties to provide us with liquidity and capital resources in the past and we may continue to do so in the future. After any such sale, we would expect to utilize the proceeds to reduce our indebtedness and to drill new wells on our remaining properties. If we cannot replace the properties sold with production from our remaining properties, our cash 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 future downturn in our business or the economy in general or otherwise conduct necessary or desirable business activities.

A breach of any of these covenants could result in a default under our credit facility. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms acceptable or favorable to us.

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

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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, 2014, our average annual estimated decline rate for our net proved developed producing reserves is 12% during the first five years, 8% in the next five years, and approximately 6% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. As our proved reserves and consequently our production decline, our cash flow from operations, and the amount that we are able to borrow under our credit facility could also decline. In addition, approximately 58% of our total estimated proved reserves at December 31, 2014 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 58% of our total estimated proved reserves as of December 31, 2014 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling and completion operations. In addition, our properties may be susceptible to drainage from production by other operations on adjacent properties. If the volume of oil and gas we produce decreases, our cash flow from operations may decrease.

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

We drill wells in unconventional formations in several emerging plays. Part of our drilling strategy to maximize recoveries from these formations involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have proven to be successful in other basins. Risks that we face include landing our well bore in the desired drilling zone, staying in the desired drilling zone, running casing the entire length of the well bore and being able to run tools and recover equipment the entire length of the well bore during completion. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date, as well as the industry's drilling and production history in these formations, is relatively limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established. In addition, based on reported decline rates in these emerging plays as well as the industry's experience in these formations, we estimate that the average monthly rates of production may decline as much as 95% during the first twelve months of production. Actual decline rates may differ significantly. Accordingly, the results of our drilling in these unconventional formations are more uncertain than drilling results in other more established plays with longer reserve and production histories.

We may not adhere to our proposed drilling schedule.

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

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

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- lease expirations.

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

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

At December 31, 2014, we had a total of $70.0 million of indebtedness under our credit facility and total indebtedness of $78.8 million (including the current portion). Our indebtedness could have important consequences to us, including:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, shoreline contamination, underground migration and surface spills or mishandling of chemical additives;

- abnormally pressured formations;

- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- leaks of gas, oil, condensate, NGL and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, or in the gathering and transportation of hydrocarbons, malfunctions of pipelines, measurement equipment or processing or other facilities in the Company’s operations or at delivery points to third parties;
- fires and explosions;

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- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

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

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

Hydraulic fracturing is the primary completion method used to extract reserves located in many of the unconventional oil and gas plays. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure, usually down tubing or casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and gas production. We use this completion technique on substantially all of our wells. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal and state levels, exploration, exploitation and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Some states in which we operate, including Texas, have recently implemented disclosure requirements related to chemicals used in hydraulic fracturing, and the U.S. Department of the Interior, Bureau of Land Management (“BLM”) is expected to finalize regulations in 2015 governing hydraulic fracturing on federal and tribal lands, including requiring chemical disclosure. Individually or collectively, such existing and new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business, financial condition and results of operations.

Hydraulic fracturing is typically regulated by state oil and gas commissions; however, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Underground Injection Control Program established under the Safe Drinking Water Act, or SDWA, and published draft permitting guidance in February 2014 addressing the performance of such activities. In May 2014, EPA announced its intent to initiate rulemaking regulations under the Toxic Substances Control Act to obtain data on chemical substances and mixtures used in hydraulic fracturing. In August 2012, the EPA published final rules under the CAA, which became effective October 15, 2012, that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 or performing reduced emission completions, also known as “green completions,” with or without combustion devices, on or after January 1, 2015. Additional regulation on air emissions resulting from hydraulic fracturing operations could result from EPA’s proposal of a new, more stringent, ozone standard if this standard is ultimately adopted and implemented by EPA. In January 2015, the Obama Administration also announced its intent to directly regulate methane emissions from the oil and gas industry. 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. For example, Texas adopted a law in June 2011 requiring disclosure to the Texas Railroad Commission and the public disclosure of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact water available for hydraulic fracturing. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, in the event state or local restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

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Certain governmental reviews were recently conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report released by the agency on December 21, 2012 and a final report expected to be available for public comment and peer review by early 2015. Moreover, in early 2015, the EPA is expected to propose effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. See "Item 1. Business – Environmental Matters – Hydraulic Fracturing " above for additional discussion related to environmental risks associated with our hydraulic fracturing activities.

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

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

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

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- limited access or damage to or destruction of our property;

- legal challenges or lawsuits;
- increased regulation of our business;
- damaging publicity and reputational harm;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

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

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

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

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

Our oil and gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for our oil and gas are typically lower than the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, 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.

During 2014, differentials averaged $(10.49) per Bbl of oil and $(0.09) per Mcf of gas. Approximately 57% of our oil and NGL production during 2014 was from the Rocky Mountain region. Historically, this region has experienced wider differentials than our Permian Basin and Gulf Coast properties. If the percentage of our production from the Rocky Mountain region continues to increase, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the realized price we receive could significantly reduce our revenues and our cash flow from operations.

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

To achieve more predictable cash flow and reduce our exposure to adverse fluctuations in the prices of oil and gas, we enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 30% of the oil production of our estimated net proved developed producing reserves (as of December 31, 2014) through December 31, 2015, 42% in 2016 and 27% for 2017. In addition, approximately 17% of 2015 gas production of our estimated net proved developed producing reserves (as of December 31, 2014) is hedged. Any new hedging arrangements will be priced at then-current market prices and may be significantly lower than the commodity swaps we currently have in place. The extent of our commodity price exposure will be related largely to the effectiveness and scope of our commodity price derivative contracts. For example, the prices utilized in our derivative contracts are currently NYMEX-based, which may differ significantly from the actual prices we receive for oil and gas which are based on the local markets where the oil and gas is produced. The prices that we receive for our oil and gas production are typically lower than the relevant benchmark prices that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential, a significant portion of which is based on the delivery location which is called the basis differential. As a result, our cash flow from operations could be affected if the basis differentials widen more than we anticipate. We currently do not have any basis differential hedging arrangements in place. Our cash flow from operations could also be affected based upon the levels of our production. If production is higher than we estimate, we will have greater commodity price exposure than we intended. If production is lower than the nominal amount that is subject to our hedging arrangements, we may be forced to satisfy all or a portion of our hedging arrangements without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows.

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

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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, 2014, we recognized a realized gain on oil and gas derivative contracts of $0.4 million and an unrealized gain of $24.9 million. The realized gain resulted in an increase in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility.

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

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

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

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

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

On July 21, 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which imposes a comprehensive regulatory scheme significantly impacting companies engaged in over-the-counter swap transactions. The Dodd-Frank Act generally applies to “swaps” entered into by “major swap participants” and/or “swap dealers,” each as defined in the Dodd-Frank Act. A swap is very broadly defined in the Dodd-Frank Act and includes an energy commodity swap. A swap dealer includes an entity that regularly enters into swaps with counterparties as an “ordinary course of business for its own account.” Furthermore, a person may qualify as a major swap participant if it maintains a “substantial position” in outstanding swaps, other than swaps used for “hedging or mitigating commercial risk” or whose positions create substantial exposure to its counterparties or the U.S. financial system. The Dodd-Frank Act subjects swap dealers and major swap participants to substantial supervision and regulation by the Commodity Futures Trading Commission, or the CFTC, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. The CFTC recently promulgated regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. Position limits for spot month limits became effective on October 12, 2012 while non-spot limits for energy-related commodities are not expected to be effective until early 2015. The CFTC also has proposed regulations to establish minimum capital and margin requirements, as well as clearing and trade-execution requirements in connection with certain derivative activities, although it’s not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rule making under Dodd Frank. In addition, the CFTC’s regulations adopted pursuant to the Dodd-Frank Act impose certain record keeping and transactional reporting requirements that may be burdensome and costly to us and to the counterparties to our commodity derivative contracts.

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

Lower oil and gas prices increase the risk of ceiling limitation write-downs.

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We use the full cost method to account for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop our oil and gas properties. Under full cost accounting rules, the net capitalized cost of our oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from our proved reserves, discounted at 10%. If the net capitalized costs of our oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but it does reduce our stockholders' equity and earnings. The risk that we will be required to write-down the carrying value of our oil and gas properties increases when oil and gas prices are low, which could be further impacted by the SEC's modernized oil and gas reporting disclosures, which require us to use an average price over the prior 12-month period, rather than the year-end price, when calculating the PV-10. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though oil and gas prices may have increased the ceiling applicable in the subsequent period.

At December 31, 2013 and 2014, the net capitalized costs of our oil and gas properties did not exceed the present value of our estimated proved reserves. If commodity prices remain at depressed levels or decrease further, we could be required to write down the carrying value of our reserves during 2015 which would also reduce our net income.

Use of our net operating loss carryforwards may be limited.

At December 31, 2014, we had, subject to the limitation discussed below, $145.5 million of net operating loss carryforwards for U.S. tax purposes. The loss carryforwards will expire in varying amounts through 2034, if not otherwise used.

The use of our net operating loss carryforwards may be limited if an "ownership change" of over 50 percentage points occurs during any three-year period. Based on current estimates, we believe that we have not surpassed this threshold.

Additionally, uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 740-10, we have established a valuation allowance of $60.1 million at December 31, 2014.

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

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

While we have not experienced significant cyber attacks, we may suffer such losses in the future. We did have a cyber attack in 2010 relating to electronic bank transfers, although the monetary loss was very minimal, additional procedures were implemented to safeguard against future cyber attacks. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber attacks.

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

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

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

We depend to a large extent on Robert L.G. Watson, our President and Chief Executive Officer, for our management and business and financial contacts. Mr. Watson may terminate his employment agreement with us at any time on 30 days' notice, but,

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if he terminates without cause, he would not be entitled to the severance benefits provided under the terms of that agreement. Mr. Watson is not precluded from working for, with or on behalf of a competitor upon termination of his employment with us. If Mr. Watson were no longer able or willing to act as President, Chief Executive Officer and Chairman of the Board, the loss of his services could have an adverse effect on our operations.

Risks Related to Our Industry

Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth.

Our revenue, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also make it uneconomical for us to increase or even continue current production levels of oil and gas.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and gas, market uncertainty and a variety of other factors beyond our control, including:

- changes in foreign and domestic supply and demand for oil and gas;
- political stability and economic conditions in oil producing countries, particularly in the Middle East;
- weather conditions;
- price and level of foreign imports;
- terrorist activity;
- availability of pipeline and other secondary capacity;
- general economic conditions;
- domestic and foreign governmental regulation; and
- the price and availability of alternative fuel sources.

Estimates of proved reserves and future net revenue are inherently imprecise.

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

The estimates of our reserves as of December 31, 2014 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the PV-10 thereof for our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2014. The average realized sales prices as of such date used for purposes of such estimates were $5.15 per Mcf of gas and $87.11 per Bbl of oil. The December 31, 2014 estimates also assume that we will make future capital expenditures of approximately $557.8 million in the aggregate primarily from 2015 through 2019, which are necessary to develop and realize the value of proved reserves on our properties. In addition, approximately 58% of our total estimated proved reserves as of December 31, 2014 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, 2014 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2014

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and costs in effect on December 31, 2014, the date of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

•supply of and demand for our oil and gas;

•actual prices we receive for our oil and gas;

•our actual operating costs;

•the amount and timing of our capital expenditures;

•the amount and timing of our actual production; and

•changes in governmental regulations or taxation.

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

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

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

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

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

Our oil and gas operations are subject to various U.S. federal, state 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 and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow from oil and gas wells below actual production capacity. U.S. federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas by-products and other substances and materials produced or used in connection with oil and gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

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

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and gas exploration and production activities in certain U.S. federal

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income tax incentives and deductions currently available to such companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

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

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of gas, and carbon dioxide, a by-product of the burning of oil, gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change and the Kyoto Protocol address greenhouse gas emissions, and several countries including the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, several states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs. At the federal legislative level, various climate change legislative measures have been considered by the U.S. Congress, but it is not possible at this time to predict when, or if, Congress will act on climate change legislation, although any major initiatives in this area may unlikely to become law in the near future due to opposition in the U.S. House of Representatives.

As a result of the U.S. Supreme Court decision in Massachusetts, et al. v. EPA, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, the EPA has issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. These regulations may apply to our operations. The EPA has adopted other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and gas exploration and production industry and the pipeline industry. The EPA's finding, the greenhouse gas reporting rule, and the rules to regulate the emissions of greenhouse gases may affect the cost of our operations and also affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and gas that we produce and as a result, our financial condition and results of operations could be adversely affected.

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) to develop 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) to audit 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.

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

Risks Related to Our Common Stock

Future issuance of additional shares of common stock could cause dilution of ownership interests and adversely affect our stock price.

We are currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. We may in the future issue previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. The potential issuance of any such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

We will not pay dividends on our common stock for the foreseeable future.

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

Shares eligible for future sale may depress our stock price.

At December 31, 2014, we had 106,186,678 shares of common stock outstanding of which 9,176,554 shares were held by affiliates and, in addition, 5,885,470 shares of common stock were subject to outstanding options granted under stock option plans (of which 4,111,853 shares were vested at December 31, 2014).

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

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

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

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the oil and gas industry;
- sales of common stock or other actions by our stockholders;
- additions or departures of key management personnel;
- commencement of or involvement in litigation;
- speculation in the press or investment community regarding our business;

- an inability to maintain the listing of our common stock on a national securities exchange;
- market conditions; and
- analysts’ estimates and other events in the oil and gas industry.

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

Subject to the rules of The NASDAQ Stock Market, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our

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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, 2014.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage (1)		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres (2)
Rocky Mountain	37,500	21,666	49,352	21,301	2,478	888	43,855
Permian Basin	18,797	14,512	13,244	11,107	12,008	5,272	30,891
Onshore Gulf Coast	8,265	7,937	5,202	4,604	3,040	1,036	13,577
Total	64,562	44,115	67,798	37,012	17,526	7,196	88,323

(1) Fee mineral acreage represents fee simple absolute ownership of the mineral estate or fraction thereof.
(2) Includes 1,217 net acres in the Permian Basin region that are included in both developed and fee mineral acres.

The flowing table sets forth Abraxas’ net undeveloped acreage subject to expire in year:

	2015	2016	2017	2018
Rocky Mountain	1,190	230	17	646
Permian Basin	2,829	822	66	—
Onshore Gulf Coast	333	687	2,336	111

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2014:

Productive Wells

	Oil		Gas	
	Gross	Net	Gross	Net
Rocky Mountain	347.0	76.8	441.0	12.1
Permian Basin	185.0	125.8	51.0	28.6
Onshore Gulf Coast	50.5	41.5	26.5	24.5

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Total	582.5	244.1	518.5	65.2

Reserves Information

The estimation and disclosure requirements we employ conform to the definition of proved reserves with the Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. This accounting standard requires that the average first-day-of-the-month price during the 12-month period preceding the end of the year be used when estimating reserve quantities and permits the use of reliable technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes.

For the year ended December 31, 2014, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for Abraxas' properties comprising approximately 99% of the PV-10 of our proved oil and gas reserves. Proved reserves for the remaining 1% of our properties were estimated by Abraxas personnel because we determined that it was not practical for DeGolyer and MacNaughton to prepare reserve estimates for these properties as they are located in a widely dispersed geographic area and have relatively low value. DeGolyer and MacNaughton's reserve report as of December 31, 2014 included a total of 318 properties and our internal report included 302 properties.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists. They do not own an interest in any of our properties and are not employed on a contingent fee basis. All reports by DeGolyer and MacNaughton were developed utilizing their own geological and engineering data, supplemented by data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 11, 2015, which contains further discussions of the reserve estimates and evaluations prepared by DeGolyer and MacNaughton as well as the qualifications of DeGolyer and MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of reserves at December 31, 2014 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 36 years of experience in reserve evaluations. The operations department of Abraxas assisted in the process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, include oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages which are obtained from other departments within Abraxas.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations or de-escalations except by contractual arrangements. For the year ended December 31, 2014, 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, 2014. All of our reserves are located in the United States.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2014

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil Equivalents (MBoe)
Proved				

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Developed	10,162	2,006	34,677	17,947
Undeveloped	19,228	1,702	21,176	24,459
Total Proved	29,390	3,708	55,853	42,406

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2012, 2013, and 2014, 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, 2014. 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, 2014 report. The average realized sales prices used for purposes of such estimates were $87.11 per Bbl of oil and $5.15 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $557.8 million in the aggregate primarily in the years 2015 through 2019, which are necessary to develop and realize the value of proved reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

You should not assume that the present value of future net revenues referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are calculated using the average first-day-of-the-month price over the prior 12-month period. Costs used in the estimated discounted future net cash flows are costs as of the end of the period. Because we use the full cost method to account for our oil and gas operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. This is known as a “ceiling limitation write-down.” This charge does not impact cash flow from operating activities but does reduce our stockholders’ equity and reported earnings. We have experienced ceiling limitation write-downs in the past and we cannot assure you that we will not experience additional ceiling limitation write-downs in the future. As of December 31, 2014, the Company’s net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. If commodity prices remain at depressed levels or decrease further, we could be required to write down the carrying value of our reserves during 2015 which would also reduce our net income.

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

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

Proved Undeveloped Reserves

Changes in PUDs. Significant changes to PUDs occurring during 2014 are summarized in the table below. Revisions of prior estimates reflect the addition of new PUDs associated with current development plans, revisions to prior PUDs, revisions to infill drilling development plans, as well as the transfer of PUDs to unproved reserve categories due to changes in development plans during the period. Our year-end development plans are consistent with SEC guidelines for PUDs development within five years

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unless specific circumstances warrant a longer development time horizon. There are no PUDs as of December 31, 2014, included in this report that are not planned to be developed within five years.

	MMBoe
PUDs at December 31, 2013	17,397
Revisions of prior estimates	4,600
Extensions, discoveries, and other additions	8,619
Conversion to developed	(5,195)
Sales	(962)
PUDs at December 31, 2014	24,459

We spent approximately $137.9 million converting proved undeveloped reserves to proved developed reserves in 2014. We added approximately 4.6MMBOE in net proved undeveloped reserves as the result of revisions in the Bakken PUD projections based on existing well performance. We added approximately 8.6 MMBOE in additional Bakken downspaced locations proved through drilling results in 2014. Additionally 5.2 MMBOE representing twenty 2013 PUD cases were drilled and completed in 2014 and moved to proved producing.

For the period ending December 31, 2014, proved producing reserves were increased by approximately 4.4 MMBoe, net, due primarily to the completion of 20 new wells during 2014. Ten of these new wells were located on the Company’s North Fork prospect acreage in McKenzie County, North Dakota, and ten were located on various acreage tracts in the Eagle Ford play of Atascosa and McMullen Counties, Texas. The Company also added 28 new Bakken proved undeveloped down-spaced locations on the Company’s North Fork and Pershing prospect acreage in McKenzie County, North Dakota. These locations were added based on the Company’s successful test of down-spacing from 1320 feet between wells in the same zone to 660 feet. Reserves attributable to these new down-spaced locations amounted to approximately 7.7 MMBoe, net. The Company also gained approximately 1.1 MMBoe of net proved undeveloped reserves in the Bakken due to upward revisions in its Bakken type curve, which curve is used to forecast results on undeveloped locations. These upward revisions were attributable to better-than-anticipated results in the Company’s existing Bakken producing wells. The Company also gained proved undeveloped reserves of approximately 2.3 MMBbls of oil, net, due to the change in classification of ten probable undeveloped Bakken cases into the proved category. These locations achieved proved status by virtue of offsetting development activity during 2014. An equivalent volume of reserves was removed from the probable undeveloped category as a result of this change in classification.

Reconciliation of Standardized Measure to PV-10

PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2013 and 2014:

December 31,

(in thousands)	2013	2014
PV-10	$425,235	$637,443
Present value of future income taxes discounted at 10%	(84,250)	(124,886)
Standardized measure of discounted future net cash flows	$340,985	$512,557

Oil and Gas Production, Sales Prices and Production Costs

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

	2012	2013	2014
Oil production (Bbls)			
Rocky Mountain	402,869	501,657	816,323
Permian Basin	113,691	100,846	86,614
Onshore Gulf Coast	86,107	224,625	491,142
Mid-Continent (4)	8,408	2,197	—
Total	611,075	829,325	1,394,079
Gas production (Mcf)			
Rocky Mountain	802,001	940,969	1,057,759
Permian Basin	1,657,165	1,288,198	1,003,018
Onshore Gulf Coast	1,257,124	1,029,346	856,928
Mid-Continent (4)	265,909	84,384	—
Total	3,982,199	3,342,897	2,917,705
NGL production (Bbls)			
Rocky Mountain	23,468	50,421	95,384
Permian Basin	82,200	88,254	79,321
Onshore Gulf Coast	2,036	7,871	32,592
Mid-Continent (4)	562	178	—
Total	108,266	146,724	207,297
Total production (MBoe) (1)	1,383	1,533	2,088
Average sales price per Bbl of oil (2)			
Rocky Mountain	$81.61	$87.80	$78.59
Permian Basin	$87.97	$91.72	$84.38
Onshore Gulf Coast	$100.31	$101.59	$88.44
Mid-Continent (4)	$90.52	$90.53	$—
Composite	$85.55	$92.02	$82.42
Average sales price per Mcf of gas (2)			
Rocky Mountain	$2.71	$3.33	$4.41
Permian Basin	$2.45	$3.47	$4.29
Onshore Gulf Coast	$2.14	$2.99	$3.73
Mid-Continent (4)	$2.00	$2.87	$—
Composite	$2.37	$3.27	$4.17
Average sales price per Bbl of NGL			
Rocky Mountain	$37.27	$40.59	$36.41
Permian Basin	$35.45	$32.12	$31.10
Onshore Gulf Coast	$27.52	$18.96	$21.41
Mid-Continent (4)	$31.72	$30.09	$—
Composite	$35.68	$34.32	$32.02
Average sales price per Boe (2)	$47.42	$60.18	$64.04
Average cost of production per Boe produced (3)			
Rocky Mountain	$17.41	$13.11	$7.36
Permian Basin	$13.11	$14.50	$15.15
Onshore Gulf Coast	$8.55	$8.34	$9.30
Mid-Continent (4)	$14.91	$15.65	$—
Composite	$13.41	$12.71	$9.22

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(1) Oil and gas were combined by converting gas to a Boe equivalent on the basis of 6 Mcf of gas to 1 Bbl of oil.
(2) Before the impact of hedging activities.
(3) Production costs include controllable direct lease operating costs but exclude ad valorem taxes, production taxes and non-recurring lease operating costs.
(4) All of our Mid-Continent properties were sold in 2013.

Within the above major operating regions, the Rocky Mountain and Onshore Gulf Coast regions represented more than 15% of our proved reserves as of December 31, 2014. The following is a summary, by product sold, for each primary field in these regions for the three years ended December 31, 2014:

	2012	2013	2014
Rocky Mountain Region			
Oil production (Bbls)			
Bakken/Three Forks	3,533	296,451	660,447
Gas production (Mcf)			
Bakken/Three Forks	3,466	351,248	570,792
NGL production (Bbls)			
Bakken/Three Forks	—	31,229	77,120
Average sales price per Bbl of oil (1)			
Bakken/Three Forks	$81.06	$88.35	$78.01
Average sales price per Mcf of gas (1)			
Bakken/Three Forks	$4.39	$2.87	$4.60
Average sales price per Bbl of NGL			
Bakken/Three Forks	$—	$37.34	$34.86
Average cost of production per Boe produced (2)			
Bakken/Three Forks	$28.50	$10.03	$6.88
Onshore Gulf Coast Region			
Oil production (Bbls)			
Eagle Ford	13,027	154,910	431,892
Gas production (Mcf)			
Eagle Ford	21,370	45,560	229,385
NGL production (Bbls)			
Eagle Ford	2,036	7,530	32,592
Average sales price per Bbl of oil (1)			
Eagle Ford	$97.46	$102.17	$88.30
Average sales price per Mcf of gas (1)			
Eagle Ford	$2.87	$3.11	$3.69
Average sales price per Bbl of NGL			
Eagle Ford	$27.52	$18.48	$21.42
Average cost of production per Boe produced (2)			
Eagle Ford	$10.79	$6.40	$7.98

(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 working interests in exploratory and development wells drilled during the three years ended December 31:

2012 (1)	2013	2014

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	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Rocky Mountain	—	—	—	—	—	—
Permian Basin	—	—	—	—	—	—
Onshore Gulf Coast	—	—	—	—	—	—
Total	—	—	—	—	—	—
Dry wells						
Permian Basin	1.0	—	2.0	2.0	—	—
Total	1.0	—	2.0	2.0	—	—
Development						
Productive						
Rocky Mountain	22.0	2.6	31.0	3.1	10.0	6.4
Permian Basin	1.0	1.0	1.0	1.0	—	—
Onshore Gulf Coast	2.0	0.5	11.0	3.9	10.0	10.0
Total	25.0	4.1	43.0	8.0	20.0	16.4

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

In addition to the above drilling activity, as of December 31, 2014 we had 17.0 gross (7.07 net) wells that were at various stages of drilling and/or completion that are not represented in the above table.

Present Activities

As of March 10, 2015, we had six gross (5.0 net) operated wells in the process of drilling and/or completing. In the following discussion, production rates do not include the impact of NGL production and shrinkage from processing including the flaring of gas. The following provides an overview of our present activities by region:

Williston Basin

At Abraxas' North Fork prospect, in McKenzie County, North Dakota, the Stenehjem 3H, producing from the Middle Bakken, averaged 1,057 Boepd (848 Bbls of oil per day, 1,254 Mcf of gas per day) over the well's peak 30 days of production. The Stenehjem 2H and 4H, producing from the Three Forks, averaged 863 Boepd (686 Bbls of oil per day, 1,062 Mcf of gas per day) over the wells' peak 30 days of production. In the Jore unit, Abraxas recently set production casing in the laterals of the Jore 5H, 6H, 7H and 8H. All four Jore wells are awaiting completion. Abraxas owns a working interest of approximately 73% and 76% in the Stenehjem and Jore wells, respectively.

Eagle Ford

At Abraxas' Jourdanton prospect in Atascosa County, Texas, the Cat Eye 1H averaged 491 Boepd (464 Bbls of oil per day, 169 Mcf of gas per day) over the well's peak 30 days of production. Since being placed on submersible pump the Cat Eye 1H averaged 587 Boepd (552 Bbls of oil per day, 211 Mcf of gas per day) over the following twelve production days. The Cat Eye 1H represents the Company's first well on the Southern fault block at Jourdanton.

Abraxas has completed drilling on the Grass Farm 2H and is awaiting completion. Abraxas owns a 100% working interest across the Jourdanton prospect.

At Abraxas' Dilworth East prospect, in McMullen County, Texas, the Company has completed drilling the R. Henry 1H and is awaiting completion. Following the completion of drilling operations on the R. Henry 1H, the Company released the Eagle Ford rig. Abraxas owns a 100% working interest in the R. Henry 1H.

Abraxas recently leased 204 incremental net acres at the Company's Dilworth East prospect in McMullen County, Texas. The prospect now consists of a combined 1,148 net contiguous acres and can accommodate up to ten 5,000-5,500 foot laterals and three 8,500 foot laterals.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist of approximately 21,000 square feet. We own the building which is subject to a real estate lien note. The note bears interest at a fixed

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rate of 4.25%, and is payable in monthly installments of principal and interest of $34,354. The note matures in July 2023. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2014, $4.3 million was outstanding on the note. We lease office space in Dickinson, North Dakota for a monthly rental of $2,245 through October 2015, increasing to $2,320 in November 2015 through October 2016 . The lease expires on October 31, 2016. We lease office space in Lusk, Wyoming for a monthly rental of $750. The lease expires on December 31, 2016. We also lease office space in Denver, Colorado for a monthly rental of $895. The lease expires on December 31, 2015.

Other Properties

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

We own 32 vehicles which are used in the field by employees. We own two workover rigs, which are used for servicing our wells. Raven Drilling owns a 2000 HP drilling rig, primarily to be used for drilling wells in the Williston Basin. We own three houses in North Dakota and a man-camp in North Dakota to house rig crews.

Item 3. Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2014, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

Item 4.Mine Safety Disclosures

Not applicable

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Part II

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

Market Information

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

	Period	High	Low
2013			
	First Quarter	$2.54	$1.93
	Second Quarter	2.55	1.99
	Third Quarter	2.72	2.01
	Fourth Quarter	3.96	2.57
2014			
	First Quarter	$4.15	$2.99
	Second Quarter	6.41	3.82
	Third Quarter	6.45	4.81
	Fourth Quarter	5.30	2.33
2015	First Quarter (Through March 10, 2015)	$3.56	$2.60

Holders

As of March 10, 2015, we had 106,191,078 shares of common stock outstanding and approximately 1,036 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 compiled by our third party compensation consultants Longnecker and Associates ("L&A"). L&A identified potential peer candidates based on 1) companies of similar size, 2) other similar companies in the oil and gas exploration industry, and 3) similar operations in comparable geographies. L&A then analyzed each company based on:

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

Using these criteria, L&A developed the following list of comparable companies: Approach Resources, Inc. (AREX), Callon Petroleum Company (CPE), Clayton Williams Energy, Inc. (CWEI), Comstock Resources, Inc. (CRK), Contango Oil & Gas Company (MCF), Emerald Oil (EOX), Evolution Petroleum Corp. (EPM), Gastar Exploration Inc. (GST), Magnum Hunter Resources Corp. (MHR), Northern Oil and Gas, Inc (NOG), Penn Virginia Corporation (PVA), Swift Energy Co. (SFY), Triangle Petroleum Corporation (TPLM) and Warren Resources Inc. (WRES). The following companies which were included in the 2013 graph were eliminated from the 2014 performance graph as L&A considered them unsuitable peers based on the criteria it established listed above: American Eagle Energy (AMZG), Cubic Energy (CBNR), Double Eagle Petroleum (DBLE), Enerjex Resources (ENRJ), Fieldpoint Petroleum (FPP), Forest Oil Corporation (FST), Goodrich Petroleum (GDP), Lucas Energy (LEI), Panhandle Oil and Gas (PHX), PetroQuest Energy Inc. (PQ), Quicksilver Resources, Inc. (KWK), Resolute Energy (REN), Rex Energy (REX), Samson Oil and Gas (SSN), Synergy Resources (SYNG), US Energy Corp (USEG) and Zaza Energy Corporation (ZAZA).

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Magnum Hunter Resources Corp was added to the index versus the 2013 performance graph due to the determination by L&A that Magnum Hunter satisfied the peer group criteria L&A had established.

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, 2009, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2010, 2011, 2012, 2013 and 2014.

	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
L&A Comparable Company Index	$ 100.00	$ 177.88	$ 128.91	$ 85.75	$ 113.76	$ 54.70
S&P 500	$ 100.00	$ 112.78	$ 112.78	$ 127.90	$ 165.76	$ 184.64
AXAS	$ 100.00	$ 238.02	$ 171.88	$ 114.06	$ 169.84	$ 153.13
12/31/13 Peer Group	$ 100.00	$ 147.95	$ 103.87	$ 69.92	$ 91.84	$ 45.00

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, 2010 through 2014. 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.

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	Year Ended December 31,				
	2010	2011	2012	2013	2014
	(In thousands, except per share data)				
Total revenue - continuing operations	$57,990	$63,105	$65,664	$92,324	$133,776
Net income (loss)	$1,766	$13,743	$(18,791)	$38,647	$63,269
Net income from continuing operations	$7,263	$14,395	$3,106	$46,841 (3)	61,951
Net (loss) income from discontinued operations	$(5,497)(1)	$(652)	$(21,897)(2)	$(8,194)(4)	1,318 (5)
Net income per common share – diluted - continuing operations	$0.02	$0.15	$0.04	$0.50	$0.61
Weighted average shares outstanding – diluted	77,224	92,244	91,914	93,538	101,468
Total assets	$182,909	$241,150	$240,607	$223,650	$374,899
Long-term debt, excluding current maturities	$140,940	$126,258	$124,101	$41,790	$76,554
Total stockholders' equity (deficit)	$(14,976)	$62,651	$46,700	$86,906	$207,495

(1) Includes proved property impairment of $4.8 million related to discontinued operations.
(2) Includes proved property impairment of $19.8 million related to discontinued operations.
(3) Includes a gain on the sale of properties of $33.4 million
(4) Includes proved property impairment of $6.0 million related to discontinued operations.
(5) Includes a gain of $1.9 million on the sale of our Canadian subsidiary.

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

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion excludes the operations of Blue Eagle, except our equity share of Blue Eagle's income (loss). The Blue Eagle joint venture was dissolved effective August 31, 2012. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See "Financial Statements and Supplementary Data" in Item 8. Also excluded from this discussion are the results of our Canadian subsidiary which was sold October 31, 2014. The results of these foreign operations are included as discontinued operations in the accompanying Consolidated Financial Statements and Notes thereto.

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 four 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;

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- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

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

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL, and gas prices in the future. The market price of oil and condensate, NGL and gas in 2015 will impact the amount of cash generated from operating activities, which will in turn impact our financial position. As of March 10, 2015, the NYMEX oil and gas price was $48.29 per Bbl of oil and $2.73, per Mcf of gas, respectively, representing declines of 48% and 36%, respectively, from the average NYMEX prices in 2014.

During 2014, the NYMEX future price for oil averaged $92.91 per barrel as compared to $98.06 per barrel in 2013. During 2014 the NYMEX future spot price for gas averaged $4.26 per MMBtu compared to $3.73 per MMBtu in 2013. Prices closed on December 31, 2014 at $53.27 per Bbl of oil and $2.89 per MMBtu of gas. If commodity prices remain at these levels or continue to decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices remain depressed or continue to decline, our revenues, profitability and cash flow from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income.

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, 2012, 2013 and 2014:

	Oil			Gas		
	2012	2013	2014	2012	2013	2014
Average realized price	$85.55	$92.02	$82.42	$2.37	$3.27	$4.17
Average NYMEX price	$94.16	$98.06	$92.91	$2.83	$3.73	$4.26
Differential	$(8.61)	$(6.04)	$(10.49)	$(0.46)	$(0.46)	$(0.09)

Our hedging arrangements equate to approximately 30% of the estimated oil production from our net proved developed producing reserves (as of December 31, 2014) through December 31, 2015, 42% in 2016, 27% in 2017. By removing a portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have in the past and will in the future sustain realized and unrealized losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts. In 2012, we incurred a realized loss of $0.5 million and an unrealized gain of $2.7 million. In 2013, we incurred a realized loss of $5.0 million and an unrealized gain of $2.6 million. In 2014 we incurred a realized gain of $0.4 million and an unrealized gain of $24.9 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at December 31, 2014:

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Contract Periods	Oil - WTI Daily Volume (Bbl)	Swap Price (per Bbl)	Gas Daily Volume (Mcf)	Swap Price (per Mcf)
2015	1,045	$85.04	1,450	$4.08
2016	948	$84.10	—	$—
2017	493	$84.18	—	$—

At December 31, 2014, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $23.2 million.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve estimates as of December 31, 2014, our average annual estimated decline rate for net proved developed producing reserves is 12% during the first five years, 8% in the next five years, and approximately 6% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures during 2014 of $192.8 million related to our exploration and development activities. We have a capital expenditure budget for 2015 of $54.0 million. Substantially all of our 2015 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Eagle Ford. The 2015 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the years ended December 31, 2012, 2013 and 2014:

	Year Ended December 31, 2012	2013	2014
Total production (MBoe)	1,383	1,533	2,088
Average daily production (Boepd)	3,779	4,201	5,720
% Oil/ NGL	52 %	64 %	77 %

Availability of Capital. As described more fully under “Liquidity and Capital Resources” below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing of derivative instruments, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of December 31, 2014, we had approximately $95.0 million of availability under our credit facility.

Borrowings and Interest. At December 31, 2014, we had a total of $70.0 million outstanding under our credit facility and total indebtedness of $78.8 million (including the current portion). If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2014, we operated properties accounting for approximately 92% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2014, we drilled or participated in 146 gross (54.2 net) wells of which 97% were commercially productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 58% of our estimated proved reserves at December 31, 2014 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.

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Results of Operations

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

	Year Ended December 31, (In thousands, except per unit data)		
	2012	2013	2014
Operating revenue (1):			
Oil sales	$52,279	$76,311	$114,898
Gas sales	9,449	10,921	12,166
NGL sales	3,862	5,036	6,637
Total operating revenues	$65,590	$92,268	$133,701
Operating income	5,532	23,097	$39,922
Oil sales (MBbls)	611	829	1,394
Gas sales (MMcf)	3,982	3,343	2,918
NGL sales (MBbls)	108	147	207
Oil equivalents (MBoe)	1,383	1,533	2,088
Average oil sales price (per Bbl)(1)	$85.55	$92.02	$82.42
Average gas sales price (per Mcf)(1)	$2.37	$3.27	$4.17
Average NGL sales price (per Bbl)	$35.68	$34.32	$32.02
Average oil equivalent sales price (Boe)	$47.42	$60.18	$64.04

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

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

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

Oil sales volumes increased to 1,394 MBbls for the year ended December 31, 2014 from 829 MBbls for the same period of 2013. The increase in oil sales volumes was due to new production brought on line in 2014. New wells brought onto production in 2014 contributed 722 MBbls to production for the year ended December 31, 2014, offset by natural field declines and property sales. Gas sales volumes decreased to 2,918 MMcf for the year ended December 31, 2014 from 3,343 MMcf for the year ended December 31, 2013. The decrease in gas production was due to natural field declines; the timing of new wells being brought on line, property sales, as well as our emphasis on drilling oil wells as opposed to gas wells. New wells brought onto production during 2014 contributed 549 MMcf to production for the year ended December 31, 2014. Due to continued weakness in gas prices, our focus during 2014 was primarily on oil and NGL projects. NGL sales increased to 207 MBbls for the year ended December 31, 2014 from 147 MBbls for the same period of 2013. The increase in NGL sales was primarily due to increased gas production from fields in West Texas, Wyoming and North Dakota that have a higher NGL content than our historical gas production.

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

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

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

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation for the year ended December 31, 2014 increased to $2.7 million from $2.1 million in 2013. The increase was due to the grant of a greater amount of srares of restricted stock in 2014 as compared to 2013.

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

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

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

Loss (Gain) on Derivative Contracts. Realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The net estimated value of our commodity derivative contracts was an asset of approximately $23.2 million as of December 31, 2014. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2014, we realized a gain on our derivative contracts of approximately $0.4 million and had an unrealized gain of $24.9 million. For the year-ended December 31, 2013, we incurred a realized loss of $5.0 million and an unrealized gain of $2.6 million on our commodity swaps.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2014 and 2013, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. The year-end amount was calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2014 which were $95.28 per Bbl for oil and $4.35 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

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

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decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

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

Comparison of Year Ended December 31, 2013 to Year Ended December 31, 2012

Operating Revenue. During the year ended December 31, 2013, operating revenue increased to $92.3 million from $65.6 million in 2012. The increase in revenue was primarily due to a 36% increase in oil sales volumes in 2013 as compared to 2012, as well as an increase in realized oil prices. Gas sales volumes were down by approximately 19%; however the decrease in gas volumes was offset by higher realized gas prices. We also had a significant increase in NGL sales volumes in 2013 as compared to 2012, which was partially offset by lower realized NGL prices. Increased sales volumes of oil and NGL contributed $20.0 million to operating revenue. Lower gas sales volumes had a negative impact on operating revenue of $1.5 million. Higher realized prices for oil and gas contributed $8.3 million to operating revenue.

Oil sales volumes increased to 829 MBbls for the year ended December 31, 2013 from 611 MBbls for the same period of 2012. The increase in oil sales volumes was due to new production brought on line in 2013. New wells brought onto production in 2013 contributed 264 MBbls to production for the year ended December 31, 2013, offset by natural field declines and property sales. Gas sales volumes decreased to 3,343 MMcf for the year ended December 31, 2013 from 3,982 MMcf for the year ended December 31, 2012. The decrease in gas production was due to natural field declines; the timing of new wells being brought on line, property sales, as well as our emphasis on drilling oil wells as opposed to gas wells. New wells brought onto production during 2013 contributed 178 MMcf to production for the year ended December 31, 2013. Due to weak gas prices, our focus during 2013 was primarily on oil and NGL projects. NGL sales increased to 147 MBbls for the year ended December 31, 2013 from 108 MBbls for the same period of 2012. The increase in NGL sales was primarily due to increased gas production from fields in West Texas, Wyoming and North Dakota that have a higher NGL content than our historical gas production.

Lease Operating Expenses (“LOE”). LOE for the year ended December 31, 2013 increased to $23.2 million from $22.6 million in 2012. The increase in LOE was primarily due to increased cost of services, and significant non-recurring LOE. The increase was partially offset by sales of producing properties in 2013, which had higher operating cost. LOE per Boe for the year ended December 31, 2013 was $15.13 compared to $16.33 for the same period of 2012. The decrease in LOE per Boe was attributable to higher sales volumes in 2013, partially offset by higher costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2013 increased to $8.4 million from $6.6 million in 2012. The increase was primarily due to increased production in 2013 as compared to 2012. Production and ad valorem taxes as a percentage of oil and gas revenue decreased to 9% for the year ended December 31, 2013 from 10% in 2012.

General and Administrative (“G&A”) Expense. G&A expense, excluding stock-based compensation, increased to $9.9 million for the year ended December 31, 2013 from $7.9 million in 2012. G&A expense per Boe was $6.45 for the year ended December 31, 2013 compared to $5.73 for the same period of 2012. The increase in G&A was primarily due to performance bonuses awarded in 2013 and expenses incurred due to a proxy contest in the first quarter of 2013.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. Stock-based compensation for the year ended December 31, 2013 and 2012, was $2.1 million for both years.

Depreciation, Depletion, and Amortization (“DD&A”) Expenses. DD&A expense increased to $25.6 million for the year ended December 31, 2013 from $21.0 million in 2012. Our DD&A rate increased primarily due to higher future development cost in the 2013 year end reserve report. DD&A per Boe for 2013 was $16.69 compared to $15.15 in 2012. The increase in DD&A per BOE was due to higher future development cost offset by higher sales volumes in 2013 as compared to 2012.

Interest Expense. Interest expense decreased to $4.6 million in 2013 from $5.5 million for 2012. The decrease was primarily due to lower levels of debt during 2013 as compared to 2012.

Income Taxes. An income tax expense of $0.7 million was recognized in 2013. Approximately $81,000 was recognized as a result of an audit of our 2009 federal income tax return. We incurred federal income tax of $0.5 million and various state income taxes of approximately $68,000 for the year ended December 31, 2013, primarily as a result of the gains realized on property sales during the year. Income tax in 2012 was the result of the Internal Revenue Service audit of our 2009 federal income tax return.

Loss (Gain) on Derivative Contracts. Realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of commodity swaps and interest rate swaps. Our interest rate swap expired in August 2012. The net estimated value of our commodity derivative contracts was a liability of approximately $4.0 million as of December 31, 2013. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2013, we realized a loss on our derivative contracts of approximately $5.0 million and had an unrealized gain of $2.6 million. For the year-ended December 31, 2012, we incurred an unrealized gain of $2.7 million on our commodity swaps. For the year ended December 31, 2012, we realized a loss on our derivative contracts of approximately $0.5 million, which included a realized loss of approximately $0.3 million on our commodity swaps and a realized loss of approximately $0.2 million on our interest rate swap.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2012, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2013, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. The year-end amount was calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2013 which were $97.33 per Bbl for oil and $3.67 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

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

Earnings from Equity Method Investment. Through August 31, 2012 we accounted for the joint venture under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in "Investment in joint venture" and was also recorded as equity investment income (loss) in "Earnings from equity method investment." The joint venture was dissolved effective

September 4, 2012, with the assets being distributed to the joint venture partners. For the year ended December 31, 2012, we reported income of $2.2 million related to Blue Eagle. See Note 2 of the Notes to Condensed Consolidated Financial Statements.

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

Liquidity and Capital Resources

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

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

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties.

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

Working Capital (Deficit). At December 31, 2014, our current liabilities of $81.3 million exceeded our current assets of $38.4 million resulting in a working capital deficit of $42.9 million. This compares to a working capital deficit of $43.2 million at December 31, 2013. Current assets at December 31, 2014 primarily consisted of cash of $3.8 million, and accounts receivable of $21.6 million and the current portion of our derivative asset of $12.2 million. Current liabilities at December 31, 2014 primarily consist of trade payables of $63.5 million, revenues due third parties of $14.4 million, current maturities of long-term debt of $2.2 million and accrued expenses of $1.1 million. The working capital deficit is funded by cash flow from operations and borrowings under our credit facility.

Capital Expenditures. Capital expenditures in 2012, 2013 and 2014 were $59.5 million, $92.5 million, and $192.8 million, respectively. The table below sets forth the components of these capital expenditures:

	Year Ended December 31,		
	2012	2013	2014
	(In thousands)		
Expenditure category:			
Acquisition of producing properties	$7,200	$—	$—
Exploration/Development	48,283	91,324	189,210
Facilities and other	4,045	1,165	3,589
Total	$59,528	$92,489	$192,799

During 2012 our expenditures were primarily for development of our existing properties, the acquisition of producing properties in West Texas and the completion of the refurbishment of our drilling rig. During 2013 and 2014, capital expenditures were primarily for development of our existing properties, as well as acquisitions of leaseholds.

We anticipate making capital expenditures in 2015 of $54.0 million. The 2015 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, and our ability to obtain permits for drilling locations. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

Year Ended December 31,

	2012	2013	2014
	(In thousands)		
Net cash provided by operating activities	$55,373	$52,479	$94,462
Net cash (used in) provided by investing activities	(37,979)	35,040	(186,800)
Net cash (used in) provided by financing activities	(15,333)	(84,389)	87,857
Total	$2,061	$3,130	$(4,481)

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

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

Operating activities for the year ended December 31, 2012 provided $55.4 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities, including the monetization of our gas derivative assets accounted for most of these funds. Investing activities used $38.0 million in 2012, primarily for the development of our oil and gas properties, the purchase and reconditioning of a drilling rig off set by the sale of producing properties. Financing activities used $15.3 million for the year ended December 31, 2012, primarily for the reduction of long-term debt.

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

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 58% of our total estimated proved reserves at December 31, 2014 were classified as undeveloped.

We have in the past, and may in the future, sell producing properties. Most recently, beginning in the third quarter of 2012 and continuing through 2014, we sold certain non-core assets for combined net proceeds of approximately $155.0 million. The net proceeds were primarily used to repay outstanding indebtedness under our credit facility.

We have also sold debt and equity securities in the past when the opportunity has presented itself. On June 18, 2014, we closed a public offering of 11.5 million shares of common stock at a public offering price of $5.00 per share for total net proceeds to us of approximately $53.8 million, after fees and expenses.

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

- Long-term debt, and
- Operating leases for office facilities.

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2014:

Contractual Obligations (In thousands)	Payments due in twelve month periods ending:				
	Total	December 31, 2015	December 31, 2016-2017	December 31, 2018-2019	Thereafter
Long-term debt (1)	$78,789	$2,235	$2,941	$70,535	$3,078
Interest on long-term debt (2)	6,781	1,845	3,423	1,045	468
Lease obligations (3)	79	47	32	—	—

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Total	$85,649	$4,127	$6,396	$71,580	$3,546

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These payments assume that we will not borrow additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.
(3) Lease on office space in Dickinson, North Dakota, which expires on October 31, 2016, office space in Lusk, Wyoming, which will expire on December 31, 2016 and office space in Denver, Colorado which will expire on December 31, 2015.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2014, our reserve for these obligations totaled $9.5 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, 2014, 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, 2014, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

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

Long-Term Indebtedness.

Long-term debt consisted of the following:

	December 31, 2013	December 31, 2014
	(In thousands)	
Credit facility	$33,000	$70,000
Rig loan agreement	6,378	4,456
Real estate lien note	4,554	4,333
	43,932	78,789
Less current maturities	(2,142)	(2,235)
	$41,790	$76,554

Credit Facility

We have a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of December 31, 2014, $70.0 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, 2014, we had a borrowing base of $165.0 million. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 0.75%—

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1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At December 31, 2014, the interest rate on the credit facility was 2.16% based on 1-month LIBOR borrowings and level of utilization.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2018. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

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

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio, as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 4.00 to 1.00.The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is defined as the sum of consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts plus expenses incurred in connection with the negotiation, execution, delivery and performance of the Credit Facility plus expenses incurred in connection with any acquisition permitted under the Credit Facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At December 31, 2014, we were in compliance with all of our debt covenants. As of December 31, 2014, the interest coverage ratio was 42.81 to 1.00, the total debt to EBITDAX ratio was 0.82 to 1.00, and our current ratio was 1.53 to 1.00.

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

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

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

Rig Loan Agreement

On September 19, 2011 Raven Drilling entered into a rig loan agreement, secured by our Oilwell 2000 HP diesel electric drilling rig (the “Collateral”). The original principal amount of the note was $7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of $179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of December 31, 2013 and 2014, $6.4 million and $4.5 million, respectively, were outstanding under the rig loan agreement.

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

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest for five years at a fixed rate of 4.25% and is payable in monthly installments of $34,354. Beginning August 20, 2018, the interest rate will adjust to the current bank prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of December 31, 2013 and 2014, $4.6 million and $4.3 million, respectively, were outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. We have entered into commodity swaps on approximately 30% of our estimated oil production from our net proved developed producing reserves (as of December 31, 2014) through December 31, 2015, 42% for 2016, and 27% for 2017.

The following table sets forth the summary position of our derivative contracts as of December 31, 2014:

Contract Periods	Oil - WTI Daily Volume (Bbl)	Swap Price (per Bbl)	Gas Daily Volume (Mcf)	Swap Price (per Mcf)
2015	1,045	$85.04	1,450	$4.08
2016	948	$84.10	—	$—
2017	493	$84.18	—	$—

By removing a portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future will sustain, realized and unrealized losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts. For the year ended December 31, 2014, we incurred a realized gain of $0.4 million and an unrealized gain of $24.9 million on our commodity derivative contracts. For the year ended December 31, 2013, we incurred a realized loss of $5.0 million and an unrealized gain of $2.6 million on our commodity derivative contracts. For the year ended December 31, 2012, we incurred a realized loss of $0.5 million and an unrealized gain of $2.7 million on our commodity derivative contracts. If the disparity between our contract prices and market prices continues, we will sustain realized and unrealized gains or losses on our derivative contracts. While unrealized gains and losses do not impact our cash flow from operations, realized gains and losses do impact our cash flow from operations. In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower. In addition, borrowings under our credit facility bear interest at floating rates. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

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

Net Operating Loss Carryforwards

At December 31, 2014, we had, subject to the limitation discussed below, $145.5 million of net operating loss carryforward tax purposes. The loss carryforward will expire through 2034, if not utilized.

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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 $60.1 million for deferred tax assets at December 31, 2014.

We account for uncertain tax positions under the provisions of ASC 740-10. ASC 740-10 did not have any effect on the Company’s financial position or results of operations for the year ended December 31, 2014 or for the year ended December 31, 2013. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2014, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2001 through 2014 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly owned subsidiary of Abraxas, have undergone an audit of their 2009 federal income tax returns. The audit of the federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of proposed adjustment of $619,000. For the year ended December 31, 2012, the Company accrued $310,000 in income tax expense related to the audit of its 2009 federal tax return. This amount was determined by an analysis of what the amount that is greater than 50% likely to be paid upon final settlement. On July 23, 2013, we settled the assessment for $391,000 resulting in $81,000 being recognized as expense in 2013.

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 2013 or 2014.

Environmental Regulations

Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs as a result of their effect on oil and gas exploration, development and production operations. These laws and regulations could cause us to incur remediation or other corrective action costs in connection with a release of regulated substances, including oil, into the environment. In addition, we have acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under our control, and under environmental laws and regulations, we could be required to remove or remediate wastes disposed of or released by prior owners or operators. We also could incur costs related to the clean-up of sites to which we sent regulated substances for disposal or to which we sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such sites. In addition, we could be responsible under environmental laws and regulations for oil and gas properties in which we own an interest but are not the operator. Moreover, we are subject to the EPA’s rule requiring annual reporting of GHG emissions.

Compliance with such laws and regulations increases our overall cost of business, but has not had, to date, a material adverse effect on our operations, financial condition, results of operations or competitive position. It is not anticipated, based on current laws and regulations, that we will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to our total exploration and development expenditure program in order to comply with such laws and regulations, but, inasmuch as such laws and regulations are frequently changed, we are unable to predict the ultimate cost of compliance or the effect on our operations, financial condition, results of operations and competitive position.

We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. In addition to the EPA's rule requiring annual reporting of GHG emissions, we are also aware of legislation proposed by United States lawmakers to reduce GHG emissions. We are unable to predict the timing, scope and effect of any such proposed laws, regulations and treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations, financial condition and competitive position.

We strive to reduce GHG emissions throughout our operations which is in the best interest of the environment and a generally good business practice. We will continue to review the risks to our business and operations associated with all environmental matters, including climate change. In addition, we will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary.

Critical Accounting Policies

The preparation of financial statements in conformity with U.S. generally accepted accounting principles (“GAAP”) requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are

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particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

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

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years. Our oil and gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from impairment testing procedures associated with the full cost method of accounting as discussed below.

Under full cost accounting rules, the net capitalized cost of oil and gas properties, less related deferred taxes, may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves on a pool by pool basis, discounted at 10%, plus the lower of cost or fair market value of unproved properties and the cost of properties not being amortized, less income taxes. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are depressed. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

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

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
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