Yuma Energy, Inc.
Form 10-K
March 30, 2015

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

FORM 10-K

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

For the fiscal year ended December 31, 2014

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

For the transition period from to

Commission File Number: 001-32989

Yuma Energy, Inc.
(Exact name of registrant as specified in its charter)

CALIFORNIA	94-0787340
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

1177 West Loop South, Suite 1825 Houston, Texas	77027
(Address of principal executive offices)	(Zip Code)

(713) 968-7000
(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, no par value per share	NYSE MKT
9.25% Series A Cumulative Redeemable Preferred Stock	NYSE MKT

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. o Yes þ No

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

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

Indicate by check mark whether 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). þ Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. o

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

Larger accelerated filer	o	Accelerated filer	o
Non-accelerated filer (Do not check if a smaller reporting company)	o	Smaller reporting company	þ

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

The aggregate market value on June 30, 2014, (the last business day of the registrant's most recently completed second fiscal quarter) of the voting shares held by non-affiliates was approximately $15,171,528 based on the closing sales price of the registrant's common stock on the NYSE MKT on such date

At March 26, 2015, 69,125,624 shares of the Registrant's common stock, no par value, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13, and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2015 annual meeting of shareholders which will be filed no later than 120 days after December 31, 2014.

TABLE OF CONTENTS

Cautionary Statement Regarding Forward-Looking Statements

Certain statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts contained in this report are forward-looking statements. These forward-looking statements can generally be identified by the use of words such as "may," "will," "could," "should," "project," "intends," "plans," "pursue," "target," "believes," "anticipates," "expects," "estimates," "predicts," or "potential," the negative of such terms or variations thereof other comparable terminology. Statements that describe our future plans, strategies, intentions, expectations, objectives, goals or prospects are also forward-looking statements. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

volatility and weakness in commodity prices for oil and natural gas and the effect of prices set or influenced by action of the Organization of the Petroleum Exporting countries ("OPEC");

our ability to successfully integrate acquired oil and natural gas businesses and operations;

the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits and will divert management's time and energy, which could have an adverse effect on our financial position, results of operations, or cash flows;

risks in connection with potential acquisitions and the integration of significant acquisitions;

we may incur more debt; higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;

our ability to successfully develop our large inventory of undeveloped acreage in our resource plays;

our oil and natural gas assets are concentrated in a relatively small number of properties;

access to adequate gathering systems, processing facilities, transportation take-away capacity to move our production to market and marketing outlets to sell our production at market prices, which is necessary to fully execute our capital program;

our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and fully develop our undeveloped acreage positions;

our ability to replace our oil and natural gas reserves;

the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;

the potential for production decline rates for our wells to be greater than we expect;

our ability to retain key members of senior management and key technical employees;

environmental risks;

drilling and operating risks;

exploration and development risks;

the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;

social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as Africa, the Middle East, and armed conflict or acts of terrorism or sabotage;

other economic, competitive, governmental, regulatory, legislative, including federal, state and tribal regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;

the insurance coverage maintained by us may not adequately cover all losses that may be sustained in connection with our business activities;

title to the properties in which we have an interest may be impaired by title defects;

management’s ability to execute our plans to meet our goals;

the cost and availability of goods and services, such as drilling rigs; and

our dependency on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Glossary of Selected Oil and Natural Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and this annual report on Form 10-K:

2-D Seismic. Geophysical data that depicts the subsurface strata in two dimensions.

3-D Seismic. Advanced technology method of detecting accumulations of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

HH. Henry Hub natural gas price index.

HLS. Heavy Louisiana Sweet oil price index.

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

LLS. Light Louisiana Sweet oil price index.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMbtu. One million British Thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

MMcf. One million cubic feet of natural gas.

Net revenue interest. An owner’s share of petroleum after satisfaction of all royalty and other non-cost bearing interests.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids.

NYMEX. The New York Mercantile Exchange.

Operator. The individual or company responsible for the exploration and/or exploitation and/or production of an oil or natural gas well or lease.

Proved developed reserves. Proved reserves that can be expected to be recovered 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, or 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 reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (“LKH”), as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (“HKO”), elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves or PUD. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is

contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has been previously completed.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spot market price. The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate oil price index, light sweet crude oil delivered to Cushing, Oklahoma, the benchmark for crude oil in the United States.

PART I

Item 1. Business.

Overview

Unless the context otherwise requires, all references in this annual report to the "Company," "Yuma," "our," "us," and "we" re to Yuma Energy, Inc. (formerly known as Pyramid Oil Company) and its subsidiaries, as a common entity. Unless otherwise noted, all information in this annual report relating to oil, natural gas and natural gas liquids reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent reserve engineers and are net to our interest. We have included certain technical terms important to an understanding of our business under the Glossary of Selected Oil and Natural Gas Terms section above. Throughout this annual report we make statements that may be classified as "forward-looking." Please refer to the Cautionary Statement Regarding Forward-Looking Statements section above for an explanation of these types of statements.

Yuma Energy, Inc. is a U.S.-based oil and gas company focused on the exploration for, and development of, conventional and unconventional oil and natural gas properties, primarily through the use of 3-D seismic surveys, in the U.S. Gulf Coast and California. We were incorporated in California on October 7, 1909. We have employed a 3-D seismic-based strategy to build a multi-year inventory of development and exploration prospects. Our current operations are focused on onshore central Louisiana, where we are targeting the Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex and Hackberry formations. In addition, we have a non-operated position in the Bakken Shale in North Dakota and operated positions in Kern and Santa Barbara Counties in California. As a result of the merger between Yuma Energy, Inc., a Delaware corporation ("Yuma Co."), and Pyramid Oil Company, the Company underwent a substantial change in ownership, management, assets and business strategy, all effective as of September 10, 2014. Our common stock is traded on the NYSE MKT under the trading symbol "YUMA." Our Series A Preferred Stock is traded on the NYSE MKT under the trading symbol "YUMAprA."

Business Strategy

Our business strategy is to achieve long-term growth in production and cash flow on a cost-effective basis. We focus on maximizing our return on capital employed and adding production and reserves through the development of our Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex, Hackberry, Bakken, Three Forks, and Monterey Shale acreage.

Several of the key elements of our business strategy are as follows:

- Ø transition existing inventory of reserves into oil and natural gas production;
- Ø add to project inventory through ongoing prospect generation, exploration and strategic acquisitions; and
- Ø retain a greater percentage working interest in, and operatorship of, our projects going forward.

Our core competencies include generating:

- Ø unconventional oil resource plays;
- Ø onshore liquids-rich projects through the use of 3-D seismic surveys; and
- Ø identification of high impact deep onshore prospects located beneath known producing trends through the use of 3-D seismic surveys.

Our Key Strengths and Competitive Advantages

We believe the following key strengths and competitive advantages will allow us to successfully execute our business strategy:

- Ø Extensive technical knowledge and history of operations in the Gulf Coast region. Since 1983 Yuma Co. or its predecessor has operated in the Gulf Coast region, which is an area that extends through Texas, Louisiana and Mississippi. Our extensive understanding of the geology and experience in interpreting well control, core and 3-D seismic data in this area provides us with a competitive advantage in exploring and developing projects in the Gulf Coast region. We have cultivated amicable and mutually beneficial relationships with acreage owners in this region and adjacent oil and natural gas operators, which generally provides for effective leasing and development activities.

- Ø In-house technical expertise in 3-D seismic programs. We design and generate in-house 3-D seismic survey programs on many of our projects. By controlling the 3-D seismic program from field acquisition through seismic processing and interpretation, we gain a competitive advantage through proprietary knowledge of the project.

- Ø Liquids-rich, quality assets with attractive economics. Our reserves and drilling locations are primarily oil plays with associated liquids-rich natural gas.

- Ø Diversified portfolio of producing and non-producing assets. Our current portfolio of producing and non-producing assets covers a large area within the U.S. Gulf Coast, the Bakken/Three Forks shale in North Dakota, and the Monterey Shale, along with shallow oil fields in central and southern California.

- Ø Significant inventory of oil and natural gas assets. We have a significant inventory of both proved reserves and significant growth assets that we believe can be developed over the near to medium term. In addition, we have the ability to organically generate new oil and natural gas prospects and projects through techniques utilized by our experienced management team, which include analyzing subsurface data, negotiating mineral rights with landowners in prospective areas, and shooting and reprocessing 3-D seismic surveys.

- Ø Company operated assets. In order to maintain better control over our assets, we have established a leasehold position comprised primarily of assets where we are the operator. By controlling operations, we are able to dictate the pace of development and better manage the cost, type, and timing of exploration and development activities.

- Ø Experienced management team. We have a highly qualified management team with many years of industry experience, including extensive experience in the Gulf Coast region. Our team has substantial expertise in the design, acquisition, processing and interpretation of 3-D seismic surveys, and our experienced operations staff allows for efficient turnaround from project identification, to drilling, to production.

- Ø Experienced board of directors. Our directors have substantial experience managing successful public companies and realizing value for investors through the development, acquisition and monetization of both conventional and unconventional oil and natural gas assets in the Gulf Coast region.

Description of Major Properties

We are the operator of properties containing approximately 82% of our proved oil and natural gas reserves as of December 31, 2014. As operator, we are able to directly influence exploration, development and production

operations. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price fluctuations, and have provided a solid foundation for our technical staff to pursue the development of our undeveloped acreage, further develop our existing properties and also generate new projects that we believe have the potential to increase shareholder value.

As is common in the industry we participate in non-operated properties on a selective basis; our non-operating participation decisions are dependent on the technical and economic nature of the projects and the operating expertise and financial standing of the operators. The following is a description of our significant oil and natural gas properties.

Greater Masters Creek Field, Allen, Vernon, Rapides and Beauregard Parishes, Louisiana. Our Greater Masters Creek Field properties are located in the Austin Chalk Trend in west central Louisiana. At December 31, 2014, we held approximately 69,470 net acres in the field. The acreage is located within an existing field which has previously been partially developed. Based on our technical analysis and independent third-party engineering, we believe there are approximately 67 operated proved undeveloped locations and 14 non-operated proved undeveloped locations that are either held by production or leases.

In the fourth quarter of 2014, we completed our second operated Austin Chalk well, the Crosby 14-1, which was drilled vertically to approximately 15,000 feet to the top of the Austin Chalk formation and then 3,100 feet horizontally in the Austin Chalk formation. Upon completion of the Crosby 14-1, we shut the well in to install surface facilities and to drill a salt water disposal well. In December 2014, we produced the well for three days to test and complete the installation of the facilities. In January of 2015 we began to produce and clean-up the production from the Crosby 14-1 well. Although early production results were encouraging, with higher oil cuts than expected, drilling mud and cuttings accumulated in the well which prevented it from flowing. We are planning operations designed to reduce or eliminate these restrictions. Work-over operations are being prepared to bring the well back on production. We hold a 61% working interest in this well.

La Posada – Bayou Hebert Field, Vermilion Parish, Louisiana. We have a 12.5% working interest in La Posada – Bayou Hebert Field. The primary objectives were the Lower Planulina Cris R sands, at a depth from approximately 17,700 to 18,250 feet. We initially generated the exploration prospect by utilizing data from a 3-D seismic survey, which resulted in a significant discovery.

The prospect was successfully tested in 2011 on the southern portion of the structure by PetroQuest Energy, Inc., the operator. A brief summary of the drilling activity to date is as follows:

1. The Thibodeaux No. 1 well was drilled to a total depth of 19,079 feet and logged a net 217 feet of hydrocarbon bearing sand. The well was put on production in March 2012.

2. The Broussard No. 2 well was drilled to a depth of 19,150 feet on the north side of the structure in 2012. This well logged a net 328 feet of hydrocarbon bearing sand in the Lower Planulina Cris R-1 and Cris R-2A, B and C sandstones. The well was put on production in September 2012.

3. The Broussard No. 1 well (partially drilled and temporarily abandoned in 2007) was re-entered and sidetracked to the upper Cris R-2 sand as an acceleration well. The Broussard No. 1 sidetrack was drilled to a depth of 18,035 feet and encountered the upper productive sand in 2013. The well was put on production in May 2013.

In November 2014, after encountering excess water production relating to the wells, the operator reconfigured the production facilities and gross production averaged approximately 52.6 MMcf/d of natural gas and 970 Bbl/d of oil (4.7 MMcf/d and 87 Bbl/d net) during the fourth quarter of 2014. During the last week in January 2015, the operator completed the installation of higher capacity water handling equipment to handle increased water production from the Broussard No. 2 and the Thibodeaux No. 1. With the installation of this equipment, the operator plans to optimize gas production within the water handling limits of the upgraded facilities. As of March 15, 2015, the field was producing approximately 59 MMcf/d of natural gas and 1,100 Bbl/d of oil gross (5.3 MMcf/d and 98 Bbl/d net). Future potential production increases and the timing of potentially recompleting the Thibodeaux No. 1 from its current “C” zone to the overlying “B” zone will depend on the performance and optimization of the well.

Livingston Prospects, Livingston Parish, Louisiana. Our primary exploration targets which produce in the area include intermediate depth Wilcox sands and the deeper lower Tuscaloosa sands. We hold an average 33% working interest across the Livingston prospects and we are the operator.

To date we have drilled five exploration wells with four discoveries on our Livingston project. Three of the wells targeted the lower Tuscaloosa sands (oil), two of which were discoveries, one well targeted the Wilcox formation (oil), and one well was drilled to a shallow Miocene target (natural gas). The shallow Miocene well has produced out and has been shut in.

We have since drilled two development wells offsetting our Lower Tuscaloosa discoveries in addition to two development wells offsetting our Wilcox discovery. One of our Wilcox development wells, the Blackwell 39-1 was drilled and completed on January 14, 2015 and has averaged 73 Bbl/d of oil gross when producing during the two months ended March 16, 2015. We anticipate placing the Blackwell 39-1 on pump during the second quarter of 2015.

Currently, four wells are producing from the lower Tuscaloosa sands and three wells are producing from the Wilcox. The average daily production from the seven wells during the three months ended December 31, 2014 was approximately 391 Bbl/d of oil gross (90 Bbl/d net).

Lake Fortuna Field (Raccoon Island), St. Bernard Parish, Louisiana. We discovered our Lake Fortuna field in 1996 when our 3-D Raccoon Island prospect was drilled. The target was a Middle Miocene sand on a known productive structure. In 2005, we acquired the majority of the working interest in Raccoon Island from Amerada Hess, and now own a working interest of 91%. During the three months ended December 31, 2014, we temporarily shut in a portion of the field to repair a salt water disposal well which curtailed production and consequently resulted in lower revenues from the field. Normal production levels in the field are approximately 250 Bbl/d of oil gross (162 Bbl/d net).

Gardner Island and Branville Bay, St. Bernard Parish, Louisiana. During the fourth quarter of 2014, we performed repair work on the salt water disposal well servicing the two fields which was completed in January 2015. This resulted in reduced production and revenues from the field in the fourth quarter due to the downtime for the repair. Since the repair, the fields were produced for approximately six weeks and then shut in for facility upgrades. We anticipate completing the upgrades in March 2015 and restoring production to approximately 250 Bbl/d gross (63 Bb/d net). Additionally, during the fourth quarter of 2014 we acquired additional interest in our Gardner Island field bringing our working interest from 7% to 34%

Amazon 3-D Project, Calcasieu and Jefferson Parishes, Louisiana. In 2011, we shot a 70 square mile 3-D seismic survey targeting the Frio (Hackberry and Marg Tex/Cib Haz/Camerina objectives). The Hackberry is a “bright spot” play for natural gas with rich condensate yields found in stratigraphic traps at depths of approximately 13,000 feet. The Marg Tex/Cib Haz/Camerina objectives are found at depths typically around 9,000 feet in structural traps independent of the underlying Hackberry.

We have recently finished drilling our Anaconda prospect, the Talbot 23-1, where we hold approximately a 45% working interest after casing point. This single well prospect is unique in that it encountered both Hackberry and Marg Tex objectives.

In the Marg Tex interval, the well logged approximately 45 feet of hydrocarbon bearing pay in four Marg Tex sands. In the Hackberry interval, we logged approximately 45 feet of hydrocarbon bearing pay in two Hackberry sands. We plan to begin completion and testing operations in the near future.

Cat Canyon Field, Santa Barbara County, California. Our Cat Canyon field is a legacy asset that was developed and owned by Pyramid Oil Company prior to our merger completed on September 10, 2014. The field produces from the Monterey formation at a depth of 4,500 feet and is nearly 2,000 feet thick. We have a 100% working interest in 120 acres held by production in this field. The field is surrounded by Monterey wells drilled from the late 1940’s through 1982 on 10 acre spacing. The wells are drilled vertically, completed naturally (without fracking) and are put on pump immediately. We plan to drill our first operated well on this property in 2015.

Bakken – Yellowstone and Southeast Homerun. At December 31, 2014, we held an average 5% non-operated working interest in 18,513 gross acres (674 net acres) in McKenzie County, North Dakota. We have interests in six producing oil wells and two active salt water disposal wells. All producing wells are located in two fields, Yellowstone and Southeast Homerun. The majority of our interests are currently operated by Zavanna, LLC. We currently estimate that approximately 140 gross drilling locations remain across our Bakken asset. In addition, we believe significant future infill and Three Forks development upside potential exists on our acreage.

Oil and Natural Gas Reserves

All of our oil and natural gas reserves are located in the United States. Unaudited information concerning the estimated net quantities of all of our proved reserves and the standardized measure of future net cash flows from the reserves is presented in Note X – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report. The reserve estimates have been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm. We have no long-term supply or similar agreements with foreign governments or authorities. We did not provide any reserve information to any federal agencies in 2014 other than to the SEC.

Estimated Proved Reserves

The table below summarizes our estimated proved reserves at December 31, 2014 based on the report prepared by NSAI. In preparing these reports, NSAI evaluated 100% of our properties at December 31, 2014. For more information regarding our independent reserve engineers, please see Independent Reserve Engineers below. The information in the following table does not give any effect to or reflect our commodity derivatives.

	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)	Present Value Discounted at 10% ($ in thousands) (2)
Proved developed (3)					
Greater Masters Creek Field (4)	515	100	1,043	789	$15,134
Other	1,520	212	6,744	2,856	79,497
Total proved developed	2,035	312	7,787	3,645	94,631
Proved undeveloped (3)					
Greater Masters Creek Field (4)	8,972	2,060	23,095	14,882	272,094
Other	525	107	4,378	1,361	14,321
Total proved undeveloped	9,497	2,167	27,473	16,243	286,415
Total proved (3)	11,532	2,479	35,260	19,888	$381,046

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(2) Present Value Discounted at 10% ("PV10") is a Non-GAAP measure that differs from the GAAP measure "standardized measure of discounted future net cash flows" in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of the PV10 value is relevant and useful to investors because it presents the estimated discounted future net cash flows attributable to our estimated proved reserves independent of our income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, we believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and natural gas properties. PV10 does not necessarily represent the fair market value of oil and natural gas properties.

PV10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For a presentation of the standardized measure of discounted future net cash flows, see Note X – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report. The table below titled “Non-GAAP Reconciliation” provides a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

Non-GAAP Reconciliation ($ in thousands)

The following table reconciles our direct interest in oil, natural gas and natural gas liquids reserves as of December 31, 2014:

Present value of estimated future net revenues (PV10)	$381,046
Future income taxes discounted at 10%	(86,591)
Standardized measure of discounted future net cash flows	$294,455

(3) Proved reserves were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month prices for each of the preceding twelve months, which were $91.48 per Bbl (WTI) and $4.35 per MMBtu (HH), for the year ended December 31, 2014. Adjustments were made for location and grade.

(4) Our Greater Masters Creek Field is our only field that contained 15% or more of our estimated proved reserves as of December 31, 2014.

Proved Undeveloped Reserves

At December 31, 2014, our estimated proved undeveloped reserves ("PUDs") were approximately 16,243 MBoe. The following table details the changes in proved undeveloped reserves for the year ended December 31, 2014 (in MBoe):

Beginning proved undeveloped reserves at January 1, 2014	16,958
Undeveloped reserves transferred to developed	(189)
Purchases of minerals-in-place	-
Extensions and discoveries	-
Production	-
Revisions	(526)
Proved undeveloped reserves at December 31, 2014	16,243

From January 1, 2014 to December 31, 2014, our PUDs decreased 4% from 16,958 MBoe to 16,243 MBoe, or a decrease of 715 MBoe. Reserves of 189 MBoe were moved from the PUD reserve category to the proved developed producing category through the drilling of the Crosby 14-1 and Bertha 8-3 wells. We incurred approximately $16.7 million in capital expenditures during the year ended December 31, 2014 in converting these wells to the proved developed reserve category. The remaining change in PUDs of 526 MBoe was a result of decreased prices and performance revisions over the time period. Based on our 2014 year-end independent engineering reserve report, we plan to drill all of our PUD drilling locations within five years.

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of the estimates, as well as economic factors such as change in product prices, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

Technology Used to Establish Reserves

Under the SEC rules proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward

from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, NSAI employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using both volumetric estimates and performance from analogous wells in the surrounding area. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Independent Reserve Engineers

We engaged NSAI to prepare our annual reserve estimates and have relied on NSAI's expertise to ensure that our reserve estimates are prepared in compliance with SEC guidelines. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are G. Lance Binder and Philip R. Hodgson. Mr. Binder has been practicing consulting petroleum engineering at NSAI since 1983. Mr. Binder is a Registered Professional Engineer in the State of Texas (No. 61794) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1978 with a Bachelor of Science degree in Chemical Engineering. Mr. Hodgson has been practicing consulting petroleum geology at NSAI since 1998. Mr. Hodgson is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1314) and has over 30 years of practical experience in petroleum geosciences. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our principal engineer was primarily responsible for overseeing our independent petroleum engineering firm during the preparation of our reserve report. His professional qualifications met or exceeded the qualifications of reserve estimators and auditors set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications included: Bachelors of Science degree in Petroleum Engineering from Texas A&M University, 1999; Masters in Finance from the University of Houston in 2008; Executive Masters of Business Administration degree from Rice University in 2011; member of the Society of Petroleum Engineers since 1998; and more than 14 years of experience in the oil and gas industry.

Internal Control over Preparation of Reserve Estimates

We maintain adequate and effective internal controls over our reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are technical information, financial data, ownership interest, and production data. The relevant field and reservoir technical information, which is updated annually, is assessed for validity when our independent petroleum engineering firm has technical meetings with our engineers, geologist, operations and land personnel. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field-level commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to our internal controls over financial

reporting, and they are incorporated in our reserve database as well and verified internally by us to ensure their accuracy and completeness. Once the reserve database has been updated with current information, and the relevant technical support material has been assembled, our independent engineering firm meets with our technical personnel to review field performance and future development plans in order to further verify the validity of estimates. Following these reviews the reserve database is furnished to NSAI so that it can prepare its independent reserve estimates and final report. The reserve estimates prepared by NSAI are reviewed and compared to our internal estimates by our principal engineer and staff in our reservoir engineering department. Material reserve estimation differences are reviewed between NSAI's reserve estimates and our internally prepared reserves on a case-by-case basis. An iterative process between NSAI and us, and additional data is provided to address the differences. If the supporting documentation will not justify additional changes, the NSAI reserves are accepted. In the event that additional data supports a reserve estimation adjustment, NSAI will analyze the additional data, and may make changes it deems necessary. Additional data is usually comprised of updated production information on new wells. Once the review is completed and all material differences are reconciled, the reserve report is finalized and our reserve database is updated with the final estimates provided by NSAI. Access to our reserve database is restricted to specific members of our reservoir engineering department and management.

Production, Average Price and Average Production Cost

The net quantities of oil, natural gas and natural gas liquids produced and sold by us for each of the years ended December 31, 2014, 2013 and 2012, the average sales price per unit sold and the average production cost per unit are presented below.

	Years Ended December 31,		
	2014	2013	2012
Production volumes:			
Crude oil and condensate (Bbls)	231,816	184,349	154,437
Natural gas (Mcf)	2,714,586	1,580,468	515,112
Natural gas liquids (Bbls)	97,783	51,875	9,571
Total (Boe) (1)	782,030	499,635	249,860
Average prices realized:			
Excluding commodity derivatives (both realized and unrealized):			
Crude oil and condensate (per Bbl)	$93.98	$104.26	$107.57
Natural gas (per Mcf)	$4.62	$3.83	$3.07
Natural gas liquids (per Bbl)	$38.44	$40.17	$42.67
Including commodity derivatives (realized only):			
Crude oil and condensate (per Bbl)	$91.74	$102.46	$106.45
Natural gas (per Mcf)	$4.32	$4.08	$4.07
Natural gas liquids (per Bbl)	$38.44	$40.17	$42.67
Production cost per Boe (2)	$11.60	$12.40	$11.99

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(2) Excludes ad valorem taxes (which are included in lease operating expenses on our Consolidated Statements of Operations in the Consolidated Financial Statements in Part II, Item 8 in this report) and severance taxes, totaling $3,741,513, $3,121,185, and $2,104,025 in fiscal years 2014, 2013, and 2012, respectively.

Effective January 1, 2013, we acquired our interest in the Greater Masters Creek Field, which contained 79% and 78% of our total proved reserves as of December 31, 2014 and 2013, respectively. No other single field accounted for 15% or more of our proved reserves as of December 31, 2014 and 2013. The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2014 and 2013, the average sales price per unit sold and the average production cost per unit for the Greater Master Creek Field are presented below.

	Years Ended December 31,	
Greater Masters Creek Field	2014	2013
Production volumes:		
Crude oil and condensate (Bbls)	45,656	24,972
Natural gas (Mcf)	170,916	85,866
Natural gas liquids (Bbls)	16,558	8,702
Total (Boe) (1)	90,700	47,985
Average prices realized: (2)		
Crude oil and condensate (per Bbl)	$95.29	$100.87
Natural gas (per Mcf)	$4.68	$4.07

Natural gas liquids (per Bbl)	$33.67	$34.98
Production cost per Boe (3)	$43.10	$55.89

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(2) Excludes commodity derivatives (realized and unrealized) as they are not recorded by specific field.

(3) Excludes ad valorem taxes (which are included in lease operating expenses on our Consolidated Statements of Operations in the Consolidated Financial Statements in Part II, Item 8 in this report) and severance taxes, totaling $1,111,162 and $875,488 in fiscal years 2014 and 2013, respectively.

Our La Posada (Bayou Herbert) field contained 17% of our total proved reserves as of December 31, 2012. No other single field accounted for 15% or more of our proved reserves as of December 31, 2012. The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the year ended December 31, 2012, the average sales price per unit sold and the average production cost per unit for our La Posada (Bayou Herbert) field are presented below.

	Year Ended December 31, 2012
La Posada (Bayou Herbert) Field	
Production volumes:	
Crude oil and condensate (Bbls)	6,780
Natural gas (Mcf)	345,309
Natural gas liquids (Bbls)	8,442
Total (Boe) (1)	72,774
Average prices realized: (2)	
Crude oil and condensate (per Bbl)	$107.68
Natural gas (per Mcf)	$3.17
Natural gas liquids (per Bbl)	$43.05
Production cost per Boe (3)	$2.54

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(2) Excludes commodity derivatives (realized and unrealized) as they are not recorded by specific field.

(3) Excludes severance taxes but includes ad valorem taxes in lease operating expenses since this well is non-operated by us and the operator does not break-out the ad valorem taxes from lease operating expenses.

Gross and Net Productive Wells

As of December 31, 2014, our total gross and net productive wells were as follows:

Oil (1)		Natural Gas (1)		Total (1)	
Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
83	42	37	2	120	44

(1) A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractions of working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production. Horizontal re-entries of existing wells do not increase a well total above one gross well. We have working interests in 10 gross wells with completions into more than one productive zone; in the table above, these wells with multiple completions are only counted as one gross well.

Gross and Net Developed and Undeveloped Acres

As of December 31, 2014, we had total gross and net developed and undeveloped leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated or permitted by state regulatory authorities. Gross acres are those acres in which a working interest is owned. The number of net acres represents the sum of fractional working interests we own in gross acres.

	Developed		Undeveloped		Total	
State	Gross	Net	Gross	Net	Gross	Net
Louisiana	100,839	52,822	28,882	20,815	129,721	73,637
North Dakota	18,553	674	-	-	18,553	674
Texas	2,761	306	-	-	2,761	306
Oklahoma	2,160	96	-	-	2,160	96
California	1,422	1,400	-	-	1,422	1,400
New York	12,246	4,082	-	-	12,246	4,082
Wyoming	7,360	3	-	-	7,360	3
Total	145,341	59,383	28,882	20,815	174,223	80,198

As of December 31, 2014, we had leases representing 2,965 net acres (1,329 of which were in the Greater Masters Creek Field) expiring in 2015; 1,921 net acres (1,647 of which were in the Greater Masters Creek Field) expiring in 2016; and 6,336 net acres (6,256 of which were in the greater Masters Creek Field) expiring in 2017 and beyond. We anticipate that our current and future drilling plans, along with selected lease extensions, will address the majority of the leases expiring in the Greater Masters Creek Field and our other fields in 2015 and beyond.

Exploratory Wells and Development Wells

Set forth below for the years ended December 31, 2014, 2013 and 2012 is information concerning our drilling activity during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells
Year	Productive	Dry	Productive	Dry	Drilled
2014	.61	-	.54	-	1.15
2013	.32	-	.57	.31	1.21
2012	.33	.28	.64	-	1.25

Present Activities

At March 25, 2015, we had 1.0 gross (.45 net) wells in the process of drilling or completing.

Supply Contracts or Agreements

Crude oil and condensate are sold through month-to-month evergreen contracts. The price is tied to an index or a weighted monthly average of posted prices with certain adjustments for gravity, BS&W (Basic Sediment and Water) and transportation. Generally, the index or posting is based on WTI (West Texas Intermediate) and adjusted to LLS (Light Louisiana Sweet) or HLS (Heavy Louisiana Sweet). For the years ended December 31, 2014, 2013 and 2012, the LLS postings averaged $3.02, $9.58, and $17.16 over WTI, respectively. Pricing for our California properties is

based on an average of specified posted prices, adjusted for gravity, transportation, and for one field, a market differential.

Our natural gas is sold under multi-year contracts with pricing tied to either first of the month index or a monthly weighted average of purchaser prices received. Natural gas liquids are also sold under multi-year contacts usually tied to the related natural gas contract. Pricing is based on published prices for each product or a monthly weighted average of purchaser prices received.

We also engage in hedging activities as discussed below in “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Hedging Activities.”

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Major Customers

The purchasers of our oil, natural gas and natural gas liquids production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2014, two individual purchasers of our production, PetroQuest Energy, LLC and GulfMark Energy, Inc. each accounted for more than 10% of our total sales, and two purchasers, Gavilon, LLC and Genesis Crude Oil, L.P. each accounted for more than 6% of our total sales, collectively representing 74% of our total sales for the year.

In 2013, two individual purchasers of our production, PetroQuest Energy, LLC and GulfMark Energy, Inc., each accounted for more than 10% of our total sales, and two purchasers, Hilcorp Energy Company and
Genesis Crude Oil, L.P., each accounted for more than 7% of our sales, collectively representing 78% of our total sales for the year.

In 2012, four individual purchasers of our production, PetroQuest Energy, LLC, GulfMark Energy, Inc., Hilcorp Energy Company, and Genesis Crude Oil, L.P., each accounted for more than 10% of our total sales, collectively representing 79% of our total sales for the year.

We believe there are adequate alternate purchasers of our production such that the loss of one or more of the above purchasers would not have a material adverse effect on our results of operations or cash flows.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental leakage or spills of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position or cash flows. For further discussion of risks see Item 1A. Risk Factors of this report.

Title to Properties

We believe that the title to our oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and natural gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following:

royalties and other burdens and obligations, express or implied, under oil and natural gas leases;

overriding royalties and other burdens created by us or our predecessors in title;

a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;

back-ins and reversionary interests existing under purchase agreements and leasehold assignments;

liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and

easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form

spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically regulate the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

New programs and changes in existing programs, however, may address various aspects of our business including natural occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and natural gas wastes and reclassify them as hazardous wastes. If such proposals were to be enacted, they could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration and production activities may be

regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff. We believe that we will be able to obtain, or be included under, these permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act ("SDWA"), the Underground Injection Control ("UIC") regulations promulgated under the SDWA and related state programs regulate the drilling and operation of salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. The well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and local, state and federal jurisdictions. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and natural gas production.

Under the direction of Congress, the EPA has undertaken a study of the effect of hydraulic fracturing on drinking water and groundwater. The EPA has also announced its plan to propose pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations. Congress may consider legislation to amend the SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Certain states, including Colorado, Utah and Wyoming, have issued similar disclosure rules. Several environmental groups have also petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning and Community Right-to-Know Act to the oil and natural gas extraction industry. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and

locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

Recently, the EPA issued four new regulations for the oil and natural gas industry, including: a new source performance standard for volatile organic compounds ("VOCs"); a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. The final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several sources, such as storage tanks and other equipment, and limits methane emissions from these sources. Compliance with these regulations will impose additional requirements and costs on our operations.

In December 2014, the EPA proposed to lower the existing 75 parts per billion ("ppb") national ambient air quality standards ("NAAQS") for ozone under the federal Clean Air Act to a range within 65-70 ppb. The EPA is also taking public comment on whether the ozone NAAQS should be revised to as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

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 require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural 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 those comprising the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the EPA has issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from our oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA has issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, President Obama released a Strategy to Reduce Methane Emissions in March 2014. Consistent with that strategy, the EPA has announced that it intends to issue a proposed rule in 2015 to set standards for methane and VOC emissions from new and modified oil and natural gas production sources and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. As another prong of the President's strategy, the federal Bureau of Land Management ("BLM") is expected to propose standards in 2015 to reduce venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and natural gas industry as compared to 2012 levels. In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have 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. Although the Company has a few future projects that could potentially involve federal lands, federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of future oil and natural gas projects.

Threatened and endangered species, migratory birds and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communication and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act and may require that information be provided to state and local government authorities and the public.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Employees and Principal Office

As of December 31, 2014, we had 41 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Our principal executive office is located at 1177 West Loop South, Suite 1825, Houston, Texas 77027, where we occupy approximately 15,180 square feet of office space. Our Bakersfield office, consisting of approximately 4,200 square feet, is located at 2008 Twenty-First Street, Bakersfield, California 93301.

We owned the following real property as of December 31, 2014, all located in Kern county in the State of California: Mullaney yard (20 acres), Miller property (112 acres), Ranton property (80 acres), Murphy property (50 acres) and in the City of Bakersfield (3 lots).

Recent Developments

Merger – Change in Management, Control and Business Strategy

On September 10, 2014, a wholly owned subsidiary of the Company merged with and into Yuma Co., in exchange for 66,336,701 shares of common stock and we changed our name to "Yuma Energy, Inc." (the "merger"). As a result of the merger, the former Yuma Co. stockholders received approximately 93% of the then outstanding common stock of the Company and thus acquired voting control. Although the Company was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of the Company by Yuma Co.

Subsequent to the merger, Sam L. Banks assumed the role of Chairman, President and Chief Executive Officer, Paul D. McKinney became Executive Vice President and Chief Operating Officer, and Kirk F. Sprunger became Chief Financial Officer, Treasurer and Corporate Secretary. Our board of directors was reconstituted to include the directors of Yuma Co., Sam L. Banks, James W. Christmas, Frank A. Lodzinski, Ben T. Morris, Richard K. Stoneburner, and Richard W. Volk. Also, as part of the merger, our headquarters were relocated to Houston, Texas.

Issuance of 9.25% Series A Cumulative Redeemable Preferred Stock

On October 23, first closing, and then on October 24, 2014, final closing, we closed a public offering of 507,739 shares of our 9.25% Series A Cumulative Redeemable Preferred Stock, no par value per share, with a liquidation preference of $25.00 per share (the "Series A Preferred Stock"), at a public offering price of $22.00 per share, with aggregate net proceeds of $10,555,893, net of the underwriters' discount and underwriters' expenses.

At-the-Market Issuance Sales Agreement

On December 19, 2014, we entered into an At-the-Market Issuance Sales Agreement (the "sales agreement") with an investment banking firm (the "Agent"). Under this sales agreement, we could issue and sell from time to time, up to $18,829,742 in the aggregate of shares of our Series A Preferred Stock and shares of our common stock. The offer and

sale of these shares are registered under a universal shelf registration statement filed with the SEC on November 21, 2013. The sales agreement provides that our Series A Preferred Stock and our common stock will be sold at market prices prevailing at the time of the sale of such shares, at no discount to market. We were not obligated to make any sales under the sales agreement. We have agreed to pay the Agent a commission rate of up to 6.0% of the gross proceeds from the sale of shares of Series A Preferred Stock and shares of our common stock sold through the Agent under the sales agreement, reimburse the Agent for certain expenses incurred in connection with entering into the sales agreement, and provide the Agent with customary indemnification rights. The full terms and text of the sales agreement were filed with our Current Report on Form 8-K on December 29, 2014. Through March 25, 2015, we have sold 37,769 shares of Series A Preferred Stock and 221,159 shares of our common stock under the sales agreement.

Amendment to Senior Credit Agreement

On January 23, 2015, we entered into the Sixth Amendment to our Credit Agreement (the “credit agreement”) with Société Générale (the “Bank”) as Administrative Agent, which provides for a line of credit until May 20, 2017. Pursuant to the credit agreement, we secured a credit facility (the “credit facility”), which is available to provide financing of up to $40.0 million. The credit agreement is secured by a first lien on substantially all of the Company’s assets. The credit facility has a $40.0 million conforming borrowing base, and is subject to redetermination on March 1 and October 1 of each year. As of March 25, 2015, the borrowing base was $40.0 million and long-term debt outstanding was approximately $26.7 million. At this time, the borrowing base is in the process of redetermination. The Company expects the borrowing base to be reset at a somewhat lower value. Amounts borrowed under the credit agreement bear interest at either (a) the LIBOR rate plus 2.25% to 3.75% or (b) the prime rate plus 1.25% to 2.75%, depending on the amount borrowed under the credit facility. The credit facility contains a number of covenants that, among other things, restrict, subject to certain exceptions, our ability to incur additional indebtedness, create liens on assets, sell certain assets and engage in certain transactions with affiliates. Additionally, the credit agreement contains a covenant restricting the payment of dividends on preferred stock if there is less than ten percent availability on the borrowing base. The credit facility also requires the maintenance of certain financial ratios. See Part II, Item 8. Notes to the Consolidated Financial Statements, Note L – Debt and Change in Banking Line and Agent Bank.

Item 1A. Risk Factors.

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under “Cautionary Statement Regarding Forward-Looking Statements” and other information included and incorporated by reference into this Annual Report on Form 10-K.

Oil and natural gas prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our credit agreement will be subject to periodic redetermination based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

the domestic and foreign supply of oil and natural gas;

the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and determine oil prices and production levels;

social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as northern Africa and the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;

the level of consumer product demand;

the growth of consumer product demand in emerging markets, such as China;

labor unrest in oil and natural gas producing regions;

weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;

the price and availability of alternative fuels;

the price of foreign imports;

worldwide economic conditions; and

the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

Our operations and future development activities are concentrated in the Greater Masters Creek Field in west central Louisiana. In the event the field does not meet our expectations with respect to drilling and future production or we are unable to develop the field due to capital constraints, our future business, financial condition and results of operations will be materially adversely affected.

As set forth elsewhere in this report, our Greater Masters Creek Field in west central Louisiana is our largest oil and gas development project. At December 31, 2014 we held approximately 69,470 net acres in the field. Although the acreage has been partially developed by prior operators, our internal geological and engineering evaluation, as substantiated by two independent third-party engineering firms, supports the presence of significant remaining proved undeveloped reserves and additional potential. Our independent petroleum engineering reserve report as of December 31, 2014 includes 67 operated proved undeveloped well locations and 14 non-operated proved undeveloped well locations that are held by production or leases in the field. During 2014, we completed our second operated Austin Chalk well, the Crosby 14-1. While this well has encountered bottom-hole pressure consistent with our third-party engineering estimates and demonstrated encouraging initial production results, we encountered significant mechanical difficulties while drilling and completing the well. Consequently, costs to drill and complete the well significantly exceeded our pre-drill estimates. In addition, this well's production has been scaled back due to restrictions in the well bore, including down-hole drilling motor components, which could not be recovered. Our current estimates of the future capital required to develop the proved undeveloped well locations in the field have been made taking into account our experience with the Crosby 14-1.

As of December 31, 2014, the field contained approximately 91.6% of our total proved undeveloped reserves and 95.0% of the PV-10 of such reserves. Additionally, the field's proved undeveloped reserves represent approximately 74.8% of our total proved reserves. Because such a significant portion of our operations are concentrated in the field, the success of our operations and our profitability may be disproportionately exposed to the effect of various events with respect to the field, including but not limited to unanticipated costs and delays in drilling, fluctuations in prices of natural gas and oil produced from wells, natural disasters, restrictive governmental regulations, transportation capacity constraints, inclement weather, curtailment of production due to unforeseen events, and any resulting delays or interruptions of production from existing or planned new wells in the field. We intend to drill and complete the proposed wells in this field in accordance with our development plan, which is based on substantial technical engineering analyses. However, in the event our assumptions and analyses regarding the field are incorrect to any significant degree, the future production from the wells to be drilled may be adversely affected, which in turn could materially adversely affect our business, financial condition and results of operations. In addition, our development plan as of January 1, 2015 assumes that the net capital for development of the field will be approximately $377.5 million. Our ability to have sufficient capital in accordance with our plan to complete the development of these undeveloped reserves will be subject to our future cash flows, future prices for oil and gas, as well as our capital raising abilities. Any significant sustained decrease in the price of oil and gas or our ability to obtain financing, either debt or equity, could have a significant negative impact on our ability to develop the field as planned and hence, realize the positive cash flow and net income as estimated elsewhere in this report.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Further deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of operational issues, weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

25

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flow and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This report contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2014, approximately 82% of our estimated reserves (as consolidated with our two subsidiaries) were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations; however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2014, 2013 and 2012, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

actual prices we receive for oil and natural gas;

actual cost of development and production expenditures;

the amount and timing of actual production; and

changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure 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 natural gas industry in general. As a corporation, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent on our future taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this report which could have a material effect on the value of our reserves.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

27

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment and increased drilling and production costs;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or salt water, into the environment;
- hazards resulting from the presence of hydrogen sulfide or other contaminants in natural gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially affected and may differ materially from those anticipated by us.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially

productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

unexpected drilling conditions;

downhole and well completion difficulties;

pressure or irregularities in formations;

equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;

adverse weather conditions, including hurricanes; and

compliance with governmental requirements.

We are subject to complex federal, state, local and other laws and regulations that from time to time are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

water discharge and disposal permits for drilling operations;

drilling bonds;

drilling permits;

reports concerning operations;

air quality, air emissions, noise levels and related permits;

spacing of wells;

rights-of-way and easements;

unitization and pooling of properties;

pipeline construction;

gathering, transportation and marketing of oil and natural gas;

taxation; and

waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations. Under these laws and other environmental health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Federal, state, tribal and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we have operated and non-operated working interests and the operator of such properties could be subject to additional levels of regulation, operational delays or increased operating costs and could have regulatory burdens imposed upon it that could make it more difficult to perform hydraulic fracturing and increase the costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the Safe Drinking Water Act ("SDWA") to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Further, the EPA is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report describing its ongoing study, and announcing its expectation that a final draft report will be released for public comment and peer review in 2014. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing, including for example, a BLM rulemaking for hydraulic fracturing practices on federal and Indian lands that has resulted in a May 2013 proposal that would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business with regard to our operated and non-operated properties.

Certain states likewise have adopted, and other states are considering the adoption of regulations that impose new or more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. 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. Such efforts have extended to bans on hydraulic fracturing.

As a working interest owner, we use a significant amount of water with respect to hydraulic fracturing operations. The inability to locate sufficient amounts of water, or dispose of or recycle water used in exploration and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to participate in certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. Compliance with environmental regulations and regulatory permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase the operating costs of our properties and cause delays, interruptions or termination of operations, all of which could have an adverse effect on our results of operations and financial condition. Further, if the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

Hydraulic fracturing involves the injection of water, sand and various chemicals under pressure into geologic formations to fracture the surrounding rock and stimulate production. This process may give rise to operational issues such as an underground migration of water and chemicals to unintended areas, wellbore integrity, possible surface spillage and contamination caused by mishandling of fracturing fluids, including chemical additives. Properly administering the hydraulic fracturing process entails operational costs and a failure to properly administer the process could cause significant remedial and financial costs.

30

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural 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 been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural 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 international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration is attempting to address climate change through a variety of administrative actions. The EPA has issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, the President released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA has released five draft white papers on methane and volatile organic compound emissions and mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities and natural gas production and transmission facilities. Building on its white papers and the public input on those documents, the EPA has announced that it intends to issue a proposed rule in the summer of 2015 to set standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. Also as part of the President's strategy, the BLM is expected to propose standards for reducing venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls or other compliance costs, and reduce demand for our products.

The ongoing implementation of federal legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation. The CFTC, in coordination with the SEC and various U.S. federal banking regulators, has issued regulations to implement the so-called “Volcker Rule” under which banking entities are generally prohibited from proprietary trading of derivatives. Although conditional exemptions from this general prohibition are available, the Volcker Rule may limit the trading activities of banking entities that have been counterparties to our derivatives trades in the past. Also, a provision of the Dodd-Frank Act known as the “swaps push-out rule” may require some of the banking counterparties to our commodity derivative contracts to “push out” some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The CFTC also has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin and position limits; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the Dodd-Frank Act and the CFTC regulations may require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain of our derivative activities. Also, the CFTC has re-proposed regulations setting 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 are expected to be made exempt from these limits. It is possible that the CFTC, in conjunction with the U.S. federal banking regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which we would be required to post collateral.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, 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 potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a consequence, 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 the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing 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.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

personal injury;

bodily injury;

third party property damage;

medical expenses;

legal defense costs;

pollution in some cases;

well blowouts in some cases; and

workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our financial position, results of operations and cash

flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The oil and natural gas industry is cyclical and, from time to time, there have been shortages of drilling rigs, equipment, supplies, water 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. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We depend on the skill, ability and decisions of third-party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of third-party operators to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could materially affect our results of operations.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into oil, natural gas, and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil, natural gas and natural gas liquids prices, such transactions may limit our potential gains and increase our potential losses if oil, natural gas and natural gas liquids prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

our production is less than expected;

there is a widening of price differentials between delivery points for our production; or

the counterparties to our hedging agreements fail to perform under the contracts.

Risks Related to the Ownership of our Common Stock

We are a “controlled company” within the meaning of the NYSE MKT rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements. As a result, our shareholders do not have the same protections afforded to shareholders of companies that are subject to such requirements.

Sam L. Banks, our Chairman, President and Chief Executive Officer, beneficially owns a majority of our common stock. As a result, we are a "controlled company" within the meaning of the NYSE MKT corporate governance standards. Under the NYSE MKT rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE MKT corporate governance requirements, including the requirements that:

a majority of our board of directors consist of independent directors;

we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and

we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

We are currently utilizing, and intend to continue to utilize, the exemption relating to the nominating committee, and we may utilize this exemption for so long as we are a controlled company. Accordingly, our shareholders do not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance requirements of the NYSE MKT.

Our common stock price has been and is likely to continue to be highly volatile.

The trading price of our common stock is subject to wide fluctuations in response to a variety of factors, including quarterly variations in operating results, announcements of drilling and rig activity, economic conditions in the natural gas and oil industry, general economic conditions or other events or factors that are beyond our control.

In addition, the stock market in general and the market for oil and natural gas exploration companies, in particular, have experienced large price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common stock regardless of our actual operating performance. In the past, following periods of volatility in the overall market and in the market price of a company's securities, securities class action litigation has been instituted against certain oil and natural gas exploration companies. If this type of litigation were instituted against us following a period of volatility in our common stock trading price, it could result in substantial costs and a diversion of our management's attention and resources, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

We are able to issue shares of preferred stock with greater rights than our common stock.

Our Restated Articles of Incorporation authorize our board of directors to issue one or more series of preferred shares and set the terms of the preferred shares without seeking any further approval from our shareholders. The preferred shares that we have issued rank ahead of our common stock in terms of dividends and liquidation rights. We may issue additional preferred shares that rank ahead of our common stock in terms of dividends, liquidation rights or voting rights. If we issue additional preferred shares in the future, it may adversely affect the market price of our common stock. We have issued in the past, and may in the future continue to issue, in the open market at prevailing prices or in capital markets offerings series of perpetual preferred stock with dividend and liquidation preferences that rank ahead of our common stock.

Because we have no plans to pay dividends on our common stock, shareholders must look solely to appreciation of our common stock to realize a gain on their investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, our credit agreement contains covenants that prohibit us from paying cash dividends on our common stock as long as such debt remains outstanding. The payment of future dividends, if any, will be determined by our board of directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. Accordingly, shareholders must look solely to appreciation of our common stock to realize a gain on their investment, which may not occur.

Risks Related to the Ownership of our Series A Preferred Stock

The Series A Preferred Stock ranks junior to all of our indebtedness and other liabilities and is effectively junior to all indebtedness and other liabilities of our subsidiaries.

In the event of our bankruptcy, liquidation, dissolution or winding-up of our affairs, our assets will be available to pay obligations on the Series A Preferred Stock only after all of our indebtedness and other liabilities have been paid. The rights of holders of the Series A Preferred Stock to participate in the distribution of our assets will rank junior to the prior claims of our current and future creditors and any future series or class of preferred stock we may issue that ranks senior to the Series A Preferred Stock. As of March 25, 2015, 545,508 shares of Series A Preferred Stock, having a liquidation value of $25 per share, are outstanding. If we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets to pay amounts due on any or all of the Series A Preferred Stock then outstanding. We and our subsidiaries have incurred and may in the future incur substantial amounts of debt and other obligations that will rank senior to the Series A Preferred Stock. At March 25, 2015, we had $26.7 million of bank debt, on a consolidated basis, ranking senior to the Series A Preferred Stock. Our credit facility prohibits payments of dividends on the Series A Preferred Stock if we fail to comply with certain financial covenants or, at certain times, if a default or event of default has occurred. Certain of our other existing or future debt instruments may restrict the authorization, payment or setting apart of dividends on the Series A Preferred Stock.

Future offerings of debt or senior equity securities may adversely affect the market price of the Series A Preferred Stock. If we decide to issue debt or senior equity securities in the future, it is possible that these securities will be governed by an indenture or other instruments containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of the Series A Preferred Stock and may result in dilution to owners of the Series A Preferred Stock. We and, indirectly, our shareholders, will bear the cost of issuing and servicing such securities. Because our decision to issue debt or equity securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. The holders of the Series A Preferred Stock will bear the risk of our future offerings, reducing the market price of the Series A Preferred Stock and diluting the value of their holdings in us.

We may not be able to pay dividends in cash on the Series A Preferred Stock.

Under California law, cash dividends may be paid only if either (1) our retained earnings exceed the amount of the distribution plus the amount, if any, of dividends in arrears on shares with preferential dividend rights, or (2) our total assets are not less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the distribution to satisfy the preferential rights upon dissolution of shareholders whose preferential rights on dissolution are superior to those receiving the distribution. Further, notwithstanding these factors, we may not have sufficient cash to pay dividends on the Series A Preferred Stock. Our ability to pay dividends may be impaired if any of the risks described in this report, were to occur. In addition, payment of our dividends depends upon our financial condition and other factors as our board of directors may deem relevant from time to time. We cannot make assurances that our business will generate sufficient cash flow from operations or that future borrowings will be available to us in an amount sufficient to enable us to make distributions on our Series A Preferred Stock, or to pay our indebtedness or to fund our other liquidity needs.

The Series A Preferred Stock has not been rated.

We have not sought to obtain a rating for the Series A Preferred Stock. No assurance can be given, however, that one or more rating agencies might not independently determine to issue such a rating or that such a rating, if issued, would not adversely affect the market price of the Series A Preferred Stock. In addition, we may elect in the future to obtain

a rating for the Series A Preferred Stock, which could adversely affect the market price of the Series A Preferred Stock. Ratings only reflect the views of the rating agency or agencies issuing the ratings and such ratings could be revised downward, placed on a watch list or withdrawn entirely at the discretion of the issuing rating agency if, in its judgment, circumstances so warrant. Any such downward revision, placing on a watch list, or withdrawal of a rating could have an adverse effect on the market price of the Series A Preferred Stock.

Holders of Series A Preferred Stock may not be able to exercise conversion rights upon a Change of Control, and, if exercisable, these conversion rights may not adequately compensate you.

Upon the occurrence of a Change of Control, each holder of the Series A Preferred Stock will have the right (unless, prior to the Change of Control Conversion Date, we have provided notice of our election to redeem some or all of the shares of Series A Preferred Stock held by such holder, in which case such holder will have the right only with respect to shares of Series A Preferred Stock that are not called for redemption) to convert some or all of such holder's Series A Preferred Stock into shares of our common stock (or under specified circumstances involving certain alternative consideration).

Although we generally may not redeem the Series A Preferred Stock prior to October 23, 2017 (and we are subject to a general prohibition on redemptions under the terms of our credit facility prior to the date which is 30 days after all of our obligations and the lender commitments under those credit facilities have been satisfied), we have a special optional redemption right to redeem the Series A Preferred Stock in the event of a Change of Control, and holders of the Series A Preferred Stock will not have the right to convert any shares that we have elected to redeem prior to the Change of Control Conversion Date.

If we do not elect to redeem or are prohibited from redeeming the Series A Preferred Stock prior to the Change of Control Conversion Date, then, upon an exercise of the applicable conversion rights, the number of shares of our common stock or other applicable consideration that the holders of Series A Preferred Stock will be entitled to receive will be limited to a maximum of 14.12 multiplied by the number of shares of Series A Preferred Stock to be converted.

The market price of the Series A Preferred Stock could be substantially affected by various factors.

The market price of the Series A Preferred Stock will depend on many factors, which may change from time to time, including:

prevailing interest rates, increases in which may have an adverse effect on the market price of the Series A Preferred Stock;

trading prices of common and preferred equity securities issued by other energy companies;

the annual yield from distributions on the Series A Preferred Stock as compared to yields on other financial instruments;

general economic and financial market conditions;

government action or regulation;

the financial condition, performance and prospects of us and our competitors;

changes in financial estimates or recommendations by securities analysts with respect to us, or competitors in our industry;

our issuance of additional preferred equity or debt securities; and

actual or anticipated variations in quarterly operating results of us and our competitors.

As a result of these and other factors, investors who purchase the Series A Preferred Stock may experience a decrease, which could be substantial and rapid, in the market price of the Series A Preferred Stock, including decreases unrelated to our operating performance or prospects.

We may issue additional shares of Series A Preferred Stock and additional series of preferred stock that rank on parity with the Series A Preferred Stock as to dividend rights, rights upon liquidation, or voting rights.

We are allowed to issue additional shares of Series A Preferred Stock and additional series of preferred stock that would rank equally to the Series A Preferred Stock as to dividend payments and rights upon our liquidation, dissolution or winding up of our affairs pursuant to our restated articles of incorporation, as amended, and the certificate of determination for the Series A Preferred Stock without any vote of the holders of the Series A Preferred Stock. The issuance of additional shares of Series A Preferred Stock and preferred stock that would rank on parity with the Series A Preferred Stock could have the effect of reducing the amounts available to the current holders of our Series A Preferred Stock upon our liquidation or dissolution or the winding up of our affairs. It also may reduce dividend payments to the current holders of the Series A Preferred Stock if we do not have sufficient funds to pay dividends on all Series A Preferred Stock outstanding and other classes of stock with equal priority with respect to dividends.

In addition, although holders of Series A Preferred Stock are entitled to limited voting rights with respect to such matters, the Series A Preferred Stock will vote separately as a class along with the holders of all other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series A Preferred Stock. As a result, the voting rights of holders of Series A Preferred Stock may be significantly diluted, and the holders of such other series of preferred stock that we may issue may be able to control or significantly influence the outcome of any vote.

Future issuances and sales of preferred stock ranking on parity with the Series A Preferred Stock, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series A Preferred Stock and our common stock to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Holders of Series A Preferred Stock have extremely limited voting rights.

Voting rights as a holder of Series A Preferred Stock is limited. Our shares of common stock are the only class of our securities that carry full voting rights. Voting rights for holders of Series A Preferred Stock exist primarily with respect to the ability to elect, voting together with the holders of any other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series A Preferred Stock, two additional directors to our board of directors, subject to certain limitations, in the event that a “Listing Event” (defined below) occurs or if we do not pay dividends on the Series A Preferred Stock for any monthly dividend period within a quarterly period for a total of six (6) consecutive or non-consecutive quarterly periods, and with respect to voting on amendments to our restated articles of incorporation, as amended, or certificate of determination relating to the Series A Preferred Stock that materially and adversely affect the rights of the holders of Series A Preferred Stock or authorize, increase or create additional classes or series of our shares that are senior to the Series A Preferred Stock. A “Listing Event” means, with respect to the Series A Preferred Stock, if that class of stock is not listed on certain specified national stock exchanges (including the New York Stock Exchange, NYSE MKT or NASDAQ) for 180 or more consecutive days. Other than the limited circumstances described in this Annual Report, holders of Series A Preferred Stock do not have any voting rights.

The Series A Preferred Stock is a relatively new issue of securities and has only a limited trading market, which may negatively affect its value and the ability to transfer and sell shares.

The Series A Preferred Stock is a relatively new issue of securities with only a limited trading market. The volume of trades of shares of the Series A Preferred Stock on the NYSE MKT is often low, and an active trading market on the NYSE MKT for the Series A Preferred Stock may not be maintained in the future and may not provide adequate

liquidity. The liquidity of any market for the Series A Preferred Stock that may exist now or in the future will depend on a number of factors, including prevailing interest rates, the dividend rate on our common stock, our financial condition and operating results, the number of holders of the Series A Preferred Stock, the market for similar securities and the interest of securities dealers in making a market in the Series A Preferred Stock. As a result, the ability to transfer or sell the Series A Preferred Stock could be adversely affected.

If the Series A Preferred Stock or our common stock is delisted, the ability to transfer or sell shares of the Series A Preferred Stock may be limited, and the market value of the Series A Preferred Stock will likely be materially adversely affected.

Other than in connection with a Change of Control, the Series A Preferred Stock does not contain provisions that are intended to protect shareholders if our common stock is delisted from the NYSE MKT. Since the Series A Preferred Stock has no stated maturity date, shareholders may be forced to hold their shares of the Series A Preferred Stock and receive stated dividends on the Series A Preferred Stock when, and if authorized by our board of directors and paid by us with no assurance as to ever receiving the liquidation value thereof. In addition, if our common stock is delisted from the NYSE MKT, it is likely that the Series A Preferred Stock will be delisted from the NYSE MKT as well. Accordingly, if the Series A Preferred Stock or our common stock is delisted from the NYSE MKT, the ability to transfer or sell shares of the Series A Preferred Stock may be limited and the market value of the Series A Preferred Stock will likely be materially adversely affected.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is included in Item 1. Business and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

Item 3. Legal Proceedings.

A description of our legal proceedings is included in Part II, Item 8. Consolidated Financial Statements and Supplementary Data, Note P – Contingencies, and is incorporated herein by reference.

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not currently involved in any legal proceedings, nor are we a party to any pending or threatened claims, that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Our common stock has been listed for trading on the NYSE MKT under the symbol "YUMA" since September 11, 2014. Prior to that date, the common stock was traded on the NYSE MKT under the symbol "PDO". The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock on the NYSE MKT.

	Common Stock Price	
	High	Low
Quarter Ended		
2013		
March 31	$4.50	$3.89
June 30	4.38	3.77
September 30	5.00	4.03
December 31	5.89	4.28
2014		
March 31	$7.15	$4.86
June 30	6.30	5.03
September 30	5.92	3.81
December 31	4.28	1.71

As of March 25, 2015, there were approximately 1,912 shareholders of record of our common stock. The actual number of holders of our common stock is greater than the number of record holders and includes shareholders who are beneficial owners, but whose shares are held in street name by brokers and nominees.

Dividends

We have not paid cash dividends on our common stock in the past two years and we do not anticipate that we will declare or pay dividends on our common stock in the foreseeable future. Payment of dividends, if any, is within the sole discretion of our board of directors and will depend, among other factors, upon our earnings, capital requirements and our operating and financial condition. In addition under California law, we may not pay a dividend if, after giving effect, we would be unable to pay our debts as they become due in the usual course of business or if our total assets would be less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the payment of the dividend to satisfy the preferential rights upon dissolution of shareholders whose preferential rights were superior to those receiving the dividend. In addition, our credit agreement does not permit us to pay dividends on our common stock.

Item 6. Selected Financial Data.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this Item.

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

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Results of Operations

Production

The following table presents the net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2014, 2013 and 2012, and the average sales price per unit sold.

	Years Ended December 31,		
	2014	2013	2012
Production volumes:			
Crude oil and condensate (Bbl)	231,816	184,349	154,437
Natural gas (Mcf)	2,714,586	1,580,468	515,112
Natural gas liquids (Bbl)	97,783	51,875	9,571
Total (Boe) (1)	782,030	499,635	249,860
Average prices realized:			
Excluding commodity derivatives (both realized and unrealized):			
Crude oil and condensate (per Bbl)	$93.98	$104.26	$107.57
Natural gas (per Mcf)	$4.62	$3.83	$3.07
Natural gas liquids (per Bbl)	$38.44	$40.17	$42.67
Including commodity derivatives (realized only):			
Crude oil and condensate (per Bbl)	$91.74	$102.46	$106.45
Natural gas (per Mcf)	$4.32	$4.08	$4.07
Natural gas liquids (per Bbl)	$38.44	$40.17	$42.67

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

Revenues

The following table presents our revenues for the years ended December 31, 2014, 2013 and 2012.

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Crude oil and condensate sales	$21,785,636	$19,220,185	$16,613,315
Natural gas sales	12,542,671	6,049,500	1,581,783
Natural gas liquids sales	3,758,875	2,083,905	408,389
Realized gain/(loss) on commodity derivatives	(1,326,467)	72,076	341,066
Unrealized gain/(loss) on commodity derivatives	4,724,985	(231,886)	1,256,918
Gas marketing sales	572,210	881,823	1,080,644
Other revenue	1,278,217	1,066,969	601,794
Total revenues	$43,336,127	$29,142,572	$21,883,909

Sale of Crude Oil and Condensate

Crude oil and condensate are sold through month-to-month evergreen contracts. The price for Louisiana production is tied to an index or a weighted monthly average of posted prices with certain adjustments for gravity, BS&W (Basic Sediment and Water) and transportation. Generally, the index or posting is based on WTI (West Texas Intermediate) and adjusted to LLS (Light Louisiana Sweet) or HLS (Heavy Louisiana Sweet). For the years ended December 31, 2014, 2013 and 2012, LLS postings averaged $3.02, $9.58 and $17.16 over WTI, respectively. Pricing for our California properties is based on an average of specified posted prices, adjusted for gravity, transportation, and for one field, a market differential.

Crude oil volumes sold increased by 25.7% for the year ended December 31, 2014 compared to the year ended December 31, 2013. New production from Bertha 8-3, Nettles 39-1 and the Pyramid wells was further enhanced by increased sales from DS&B 117, Crosby 12-1, Quinn 13-1, Starns 38-1 and Weyerhaeuser 57-3 after successful work-over operations. Increased net revenue interests on the La Posada wells were only partially offset by reduced production from Broussard No. 2 and Thibodeaux No. 1. Further reductions were due to the shut-in of the Main Pass 2 and Main Pass 4 wells for salt water disposal well work and declining production from Weyerhaeuser 9-1, Weyerhaeuser 57-2 and the Bakken wells in North Dakota. Realized crude oil prices experienced a 10.5% decrease from the year ended December 31, 2013 to the year ended December 31, 2014.

For the year ended December 31, 2013 compared to the same period of 2012, crude oil volumes increased by 19.4% as a result of new production at Broussard No. 1 and No. 2, Crosby 12-1, Starns 38-1 and the Addison acquisition properties, as well as increased production from the Bakken wells. These were partially offset by volume declines at Raccoon Island, DS&B 117 and Weyerhaeuser 57-3. A 3.7% realized price decrease during the same period was a further offset to the production increases.

Sale of Natural Gas and Natural Gas Liquids

Our natural gas is sold under multi-year contracts with pricing tied to either first of the month index or a monthly weighted average of purchaser prices received. Natural gas liquids are also sold under multi-year contracts usually tied to the related natural gas contract. Pricing is based on published prices for each product or a monthly weighted average of purchaser prices received.

For the year ended December 31, 2014 compared to the year ended December 31, 2013, a 71.8% increase in natural gas volumes sold was primarily due to increased production at Crosby 12-1 and the La Posada net revenue increases, partially offset by production declines at Broussard No. 2 and Thibodeaux No. 1. During the same period, realized natural gas prices increased by 5.9%.

For the year ended December 31, 2013, natural gas volumes increased 207% compared to the previous year, with La Posada, Crosby 12-1 and the Addison acquisition wells as the primary contributors. Average realized natural gas prices increased only slightly during the same period, from $4.07 in 2012 to $4.08 in 2013.

Increased natural gas sales at La Posada and Crosby 12-1 contributed to increased natural gas liquids (NGL) revenues, resulting in an 80.4% increase in natural gas liquids revenues for the year ended December 31, 2014 over the year ended December 31, 2013. The 410% increase in natural gas liquids for the year ended December 31, 2013 over the same period in 2012 was a result of the Addison acquisition, La Posada increased production and new production from the Crosby 12-1.

Gas Marketing

Gas marketing sales are natural gas volumes purchased from certain of our operated wells and the aggregated volumes sold with a mark-up of $.03 per MMBtu. Our wholly-owned subsidiary, Texas Southeastern Gas Marketing Company (“Marketing”), purchases and sells natural gas on our behalf and our working interest partners.

Expenses

Lease Operating Expenses

Our lease operating expenses (“LOE”) and LOE per Boe for the years ended December 31, 2014, 2013 and 2012, are set forth below:

	Years Ended December 31,		
	2014	2013	2012
Lease operating expenses	$12,816,725	$9,316,364	$5,098,868
LOE per Boe	$16.39	$18.65	$20.41

LOE includes all costs incurred to operate wells and related facilities, both operated and non-operated. In addition to direct operating costs such as labor, repairs and maintenance, equipment rentals, materials and supplies, fuel and chemicals, LOE also includes severance taxes, product marketing and transportation fees, insurance, ad valorem taxes and operating agreement allocable overhead. LOE excludes costs classified as re-engineering and workovers. If severance and ad valorem taxes were not included in the above table, LOE would have been reduced by $3,741,513, $3,121,185 and $2,104,025 during the years ended December 31, 2014, 2013 and 2012, respectively, and operating costs per barrel of oil equivalent would have been reduced to $11.60, $12.40 and $11.99 for the years ended December 31, 2014, 2013 and 2012, respectively.

The 37.6% increase in LOE for the year ended December 31, 2014 compared to the year ended December 31, 2013 was primarily due to maintenance projects at Raccoon Island, Crosby 21A-1 and Quinn 13-1; an increased working interest for the La Posada wells due to achieving payout; and LOE for the Crosby 12-1 well and the Pyramid properties. LOE per barrel of oil equivalent decreased by 12.1% for the same period generally due to increased sales volumes.

The Addison acquisition properties and new wells at Crosby 12-1 and Starns 38-1 caused an 82.7% increase in LOE for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The significant increase in sales volumes over the same period resulted in an LOE per barrel decrease of 8.6%.

Re-engineering and Workovers

Re-engineering and workover expenses include the costs to restore or enhance production in current producing zones as well as costs of significant non-recurring operations.

Workover expenses for the years ended December 31, 2014, 2013 and 2012 totaled $3,084,972, $2,521,707, and $433,599, respectively. Workover expenses increased in the year ended December 31, 2014 compared to the same period in 2013 due to work on the Gardner Island and Raccoon Island salt water disposal wells. The increase in workover expenses for the year ended December 31, 2013 compared to the same period in 2012 were primarily due to major re-engineering programs on our Livingston properties, the USA 34-1 well acquired from Addison, and the non-operated DS&B 117 well, in addition to non-recurring operation expenses for the Crosby 12-1 salt water disposal and costs to bring various Addison-acquired wells to producing standards.

General and Administrative Expenses

Our general and administrative ("G&A") expenses for the years ended December 31, 2014, 2013 and 2012, are summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
General and administrative:			
Stock-based compensation	$4,293,855	$589,164	$-
Other	11,970,855	8,253,038	6,928,704
Capitalized	(3,442,095)	(2,786,669)	(2,589,342)
Net	$12,822,615	$6,055,533	$4,339,362

G&A expenses primarily consist of overhead expenses, employee remuneration and professional and consulting fees. We capitalize certain G&A expenditures where they satisfy the criteria for capitalization under GAAP as relating to oil and natural gas exploration activities following the full cost method of accounting.

For the year ended December 31, 2014, net G&A expenses were $6,767,082, or 112% over the amount for the prior year ended December 31, 2013. Stock-based compensation increased substantially over the prior year as a direct result of the closing of the merger. Over several years preceding the merger, we granted restricted stock awards dependent on the Company becoming a publically traded enterprise. Once that condition had been satisfied, we began amortizing the fair market value of these awards over the remaining service period required for vesting. This stock-based compensation, net of amounts capitalized, totaled $3,388,321 and $452,058 for fiscal years 2014 and 2013, respectively. Additionally, non-recurring professional costs associated with the merger and costs to explore other public listing options totaled $2,935,536 and $24,592 in fiscal years 2014 and 2013, respectively. Excluding these costs for prior stock-based compensation and the merger, along with Pyramid's 2014 G&A costs of $127,534, net G&A expenses for 2014 were $792,341, or 14%, over 2013. This increase was primarily the result of five (net) employee additions in 2014.

Excluding the net stock-based compensation and merger costs for 2013 mentioned above, G&A expenses for 2013 were $1,239,521, or 29%, higher than G&A expenses in 2012. An increase in salaries and overall headcount as well as other general overhead expenses accounted for this increase.

Depreciation, Depletion and Amortization

Our depreciation, depletion and amortization ("DD&A") for the years ended December 31, 2014, 2013 and 2012, is summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
DD&A	$19,664,991	$12,077,368	$5,074,070

The net quantities of oil, natural gas and natural gas liquids produced and sold by us increased by 57% for the year ended December 31, 2014 compared to the year ended December 31, 2013, and increased by 100% for the year ended December 31, 2013 compared to the year ended December 31, 2012. This increase in production was the primary factor for the increase in DD&A in 2014 over 2013. See "Production" above for the volumes of oil, natural gas and natural gas liquids production.

DD&A for 2013 was up from 2012 primarily due to the Addison acquisition, which increased oil and gas properties before asset retirement obligations ("ARO") by $7,170,715. The increase to property for the Addison ARO was $6,043,412. Future development costs increased by $213,711,517 to $423,330,417, a 102% increase, largely due to 33 additional Addison PUD locations. Depletion per barrel went from $19.84 to $23.87. At January 1, 2013, the effective date of the Addison acquisition, the acquisition added 6,145 MBbls of oil, 17,130 MMcf of gas and 1,573 MBbls of natural gas liquids.

NON-GAAP FINANCIAL MEASURES

Adjusted EBITDA

The following table reconciles reporting net income to EBITDA and Adjusted EBITDA for the periods indicated:

	Years Ended December 31,		
	2014	2013	2012
Net Income (Loss)	$(20,225,150)	$(33,050,103)	$(14,769,468)
Add: Depreciation, depletion & amortization of property and equipment	19,664,991	12,077,368	5,074,070
Add: Interest expense, net of interest income and amounts capitalized	302,568	560,340	201,945
Add (deduct): Income tax expense (benefit)	(2,553,854)	3,080,272	3,098,309
EBITDA	(2,811,445)	(17,332,123)	(6,395,144)
Add: Costs to obtain a public listing	2,935,536	24,592	-
Add: Increase in value of preferred stock derivative liability	15,676,842	26,258,559	17,098,504
Add: Stock-based compensation net of capitalized cost	3,388,321	452,058	-
Add: Accretion of asset retirement obligation	604,511	668,497	265,323
Add: Bank mandated commodity derivative novation cost	-	175,000	-
Deduct: Amortization of benefit from commodity derivatives sold	(93,750)	(72,600)	(112,508)
Add (deduct): Net commodity derivatives mark-to-market loss (gain)	(4,724,985)	231,886	(1,256,918)
Adjusted EBITDA	$14,975,030	$10,405,869	$9,599,257

“EBITDA” represents earnings before interest, taxes, depreciation, depletion and amortization, and is a non-GAAP financial measure. Because the Company makes other adjustments to its EBITDA formula by considering the change in the preferred stock derivative liability, stock-based compensation net of capitalized cost, accretion of asset retirement obligations, costs to obtain a public listing, the merger costs, and changes in commodity derivative values, management refers to this metric as Adjusted EBITDA and it is provided as an additional metric that is used by the Company’s board of directors and management to measure operating performance and trends. Adjusted EBITDA for the year ended December 31, 2014 increased from 2013 by $4,569,131 (44%) and from 2012 by $5,375,773 (56%), Adjusted EBITDA increased in 2013 from 2012 by $806,612 (8%).

Adjusted EBITDA is presented based on management’s belief that it will enable a user of the financial information to understand the impact of these items on reported results. Additionally, this presentation provides a helpful comparison to similarly adjusted measurements of prior periods. Adjusted EBITDA is not a measure of financial performance under GAAP and should not be considered as an alternative to net income, earnings per share and cash flow from operations, as defined by GAAP. Adjusted EBITDA may not be comparable to similarly named non-GAAP financial measures that other companies may use and may not be useful in comparing the performance of those companies to the Company’s performance.

Interest Expense

Our interest expense for the years ended December 31, 2014, 2013 and 2012, is summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
Interest expense	$1,385,550	$1,599,492	$891,173
Interest capitalized	(1,059,350)	(1,031,816)	(681,090)
Net	$326,200	$567,676	$210,083
Bank debt	$22,900,000	$31,215,000	$17,875,000

Our line of credit was used to fund the $7.5 million purchase of the Addison acreage at the start of the 2013 second quarter. Debt increased again towards the end of 2013 to finance the drilling of the Crosby 12-1. Debt decreased in fiscal year 2014 when net proceeds from the sale of the issuance of the Series A Preferred Stock were used to pay down debt by $10.4 million during October 2014.

From September 2012 to May 2013, there was turnover in the participants of our syndicated bank credit facility which generated additional fees classified as interest expense, primarily during 2013. For a complete narrative of these costs and other bank administrative fees in interest expense, refer to Note L – Debt and Change in Banking Line and Agent Bank in the Notes to Consolidated Financial Statements included in this report.

Income Tax Expense

The following summarizes our income tax expense (benefit) and effective tax rates for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
Consolidated net income (loss) before income taxes	$(22,779,004)	$(29,969,831)	$(11,671,159)
Income tax expense (benefit)	(2,553,854)	3,080,272	3,098,309
Effective tax rate	11.21%	(10.28)%	(26.55)%

Additionally, differences between the U.S. federal statutory rate of 35% and our effective tax rates are due to the tax effects of the excess of book carrying value over the tax basis in the full cost pool and the net operating loss carryforwards for each period. No tax benefit has been recognized for non-deductible expenses. Refer to Note O - Income Taxes in the Notes to Consolidated Financial Statements included in this report.

Liquidity and Capital Resources

Cash Flows

Our net increase in cash for the years ended December, 31, 2014, 2013 and 2012, is summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
Cash flows provided by operating activities	$24,466,300	$14,912,903	$3,246,663
Cash flows used for investing activities	(18,088,363)	(27,253,041)	(28,762,394)
Cash flows provided by (used for) financing activities	985,874	11,249,627	29,879,721
Net increase (decrease) in cash	$7,363,811	$(1,090,511)	$4,363,990

Cash Flows From Operating Activities

Cash flows from operations for the year ended December 31, 2014 increased by $9,553,397, or 64%, over fiscal year 2013 primarily due to increased working interest in the La Posada field, new production from the Bertha 8-3 and the Nettles 39-1, the addition of the California production after the merger, and increased production at the Crosby 12-1 and Quinn 13-1 wells. These increases were somewhat mitigated by higher lease operating expenses associated with increased production.

Cash flows from operations for the year ended December 31, 2013 increased by $11,666,240, or 359%, over fiscal year 2012, primarily due to new production at La Posada, the Addison acquisition, and the Bakken wells in North Dakota. These increases were partially offset by volume declines at Raccoon Island and increases in lease operating expenses associated with increasing production.

Cash Flows From Investing Activities

During the year ended December 31, 2014, the Greater Masters Creek Field accounted for $18,225,766 of our total oil and natural gas investing activities. Of that, $16,449,165 was spent to drill and complete the Crosby 14-1 well and its related salt water disposal well. The remaining $1,776,601 was spent on lease-related activities and preliminary costs for the next wells to be drilled in the field. At the Livingston 3D Project, $1,157,071 was spent to drill and complete the Nettles 39-1 well, along with $1,047,656 to drill the Blackwell 39-1, which was completed in the first quarter of 2015. Lease-related costs totaled $484,583. The Talbot 23-1 well in the Amazon 3D Project was spudded in early January 2015, and we incurred $364,411 in preliminary costs in 2014. Lease-related costs totaled $732,899. Additionally, $816,970 was spent evaluating and identifying development opportunities for our new producing properties in California. A net credit of $667,338 for insurance recovery on the Grief Bros. No. 1 created a credit balance for recompletions, capital workovers and P&A for the period ended December 31, 2014.

During 2013, we realized proceeds from the sale of interests in our projects and the sale of a salt water disposal well of $882,666. During 2012, we had proceeds of $1,386,649 from the sales of interests in our various projects including our Amazon 3-D Seismic Project, Tigre Lagoon 3-D Seismic Project, and several individual wells, including Piranha and Musial. During 2013, we completed the Addison acquisition of producing oil and natural gas properties including the assumption of certain liabilities for a cost of $7,350,000. During 2012, we completed two significant acquisitions, one non-operated joint venture of development acreage in the Bakken region of North Dakota for $4,175,000, and a second operated acreage position in the Greater Masters Creek Field of the Austin Chalk Trend in Central Louisiana for $8,891,134.

The following summarizes the expenditures for investing activities by type:

	Years Ended December 31,		
	2014	2013	2012
Acquisition of acreage and new properties	$4,924,999	$11,966,227	$18,830,912
Drilling and completion	19,537,826	11,788,741	11,668,105
Recompletions, capital workovers and plugging and abandoning (“P&A”)	(346,787)	2,412,658	978,364
Total oil and natural gas investing activities	24,116,038	26,167,626	31,477,381
Corporate office property and equipment purchases	100,812	80,507	319,249
Total cash used for capitalized expenditures on property and equipment	24,216,850	26,248,133	31,796,630
Proceeds from sale of property	(667,267)	(902,166)	(1,386,649)
Cash received in merger	(4,550,082)	-	-
Short-term investments retired	(2,125,541)	-	-
(Decrease) increase in noncurrent receivable from affiliate	(95,634)	2,493	2,486
Cash flows used in investing activities, including accounts payable	16,778,326	25,348,460	30,412,467
Change in capital expenditures financed by accounts payable	1,310,037	1,904,581	(1,650,073)
Cash flows used for investing activities	$18,088,363	$27,253,041	$28,762,394

Cash Flows From Financing Activities

Our cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices. Although we seek to mitigate this risk by hedging a significant portion of future crude oil and natural gas production

out two years (three to five years historically), a significant deterioration in commodity prices negatively impacts revenues, earnings, and cash flows, capital spending, and potentially our liquidity. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile or as impactful as commodity prices in the short-term.

We expect to finance future acquisition, development and exploration activities through available working capital, cash flows from operating activities, advances from our credit facility, sale of non-strategic assets, and the issuance of additional equity/debt securities. In addition, we may slow or accelerate our development of existing reserves to more closely match our projected cash flows.

On October 23 and 24, 2014, we issued 507,739 shares of Series A Preferred Stock in an underwritten public offering. The net proceeds to us from the offering of the Series A Preferred Stock were approximately $10.0 million, after deducting the underwriting discount and offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings under our credit facility.

At December 31, 2014, we had a $40.0 million conforming borrowing base with $22.9 million advanced, leaving an available borrowing capacity of $17.1 million. The borrowing base is currently undergoing review.

	Years Ended December 31,		
	2014	2013	2012
Credit Facility:			
Balances outstanding, beginning of year	$31,215,000	$17,875,000	$2,975,000
Activity	(8,315,000)	13,340,000	14,900,000
Balances outstanding, end of period	$22,900,000	$31,215,000	$17,875,000

Other than the credit facility, we had debt of $282,843, $178,027 and $183,601 at December 31, 2014, 2013 and 2012, respectively, from an installment loan financing oil and natural gas property insurance premiums. We had a cash balance of $11.6 million and short-term investments of $1.2 million at December 31, 2014.

Hedging Activities

Current Commodity Derivative Contracts

We seek to reduce our sensitivity to oil and natural gas price volatility and secure favorable debt financing terms by entering into commodity derivative transactions which may include fixed price swaps, price collars, puts, calls and other derivatives. We believe our hedging strategy should result in greater predictability of internally generated funds, which in turn can be dedicated to capital development projects and corporate obligations.

Fair Market Value of Commodity Derivatives

	December 31, 2014		December 31, 2013	
	Oil	Natural Gas	Oil	Natural Gas
Assets				
Current	$1,851,542	$1,486,995	$-	$-
Noncurrent	1,006,845	396,264	818,637	-
Liabilities				
Current	-	-	(423,217)	(253,915)
Noncurrent	-	-	-	(218,649)

Assets and liabilities are netted within each commodity on the balance sheet as all contracts are with the same counterparty. For the balances without netting, refer to Part II, Item 8. Notes to the Consolidated Financial Statements, Note H – Commodity Derivative Instruments.

The fair market value of our commodity derivative contracts in place at December 31, 2014 were net assets of $4,741,646.

We expect to reclassify losses on commodity derivatives of $33,249 net after taxes into earnings from accumulated other comprehensive income during the year ending December 31, 2015; however, actual cash settlement gains and losses recognized may differ materially.

See Part II, Item 8. Notes to the Consolidated Financial Statements, Note H – Commodity Derivative Instruments, for additional information on our commodity derivatives.

Hedging commodity prices for a portion of our production is a fundamental part of our corporate financial management. We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities of our production. In implementing our hedging strategy we seek to:

effectively manage cash flow to minimize price volatility and generate internal funds available for operations, capital development projects and additional acquisitions; and

ensure our ability to support our exploration activities as well as administrative and debt service obligations.

Estimating the fair value of derivative instruments requires complex calculations, including the use of a discounted cash flow technique, estimates of risk and volatility, and subjective judgment in selecting an appropriate discount rate. In addition, the calculations use future market commodity prices which, although posted for trading purposes, are merely the market consensus of forecasted price trends. The results of the fair value calculation cannot be expected to represent exactly the fair value of our commodity derivatives. We currently obtain fair value positions from our counterparties and compare that value to the calculated value provided by our outside commodity derivative consultant. We believe that the practice of comparing the consultant's value to that of our counterparties, who are more specialized and knowledgeable in preparing these complex calculations, reduces our risk of error and approximates the fair value of the contracts, as the fair value obtained from our counterparties would be the cost to us to terminate a contract at that point in time.

Commitments and Contingencies

We had the following contractual obligations and commitments as of December 31, 2014:

	Debt (1)	Asset for Commodity Derivatives (2)	Operating Leases	Asset Retirement Obligations
2015	$282,843	$3,338,537	$567,480	$-
2016	-	1,403,109	575,868	-
2017	22,900,000	-	561,106	2,815,296
2018	-	-	2,264	766,911
2019	-	-	-	330,504
Thereafter	-	-	-	8,575,059
Totals	$23,182,843	$4,741,646	$1,706,718	$12,487,770

(1) Does not include future commitment fees, interest expense or other fees because our credit agreement is a floating rate instrument, and we cannot determine with accuracy the timing of future loans, advances, repayments or future interest rates to be charged.

(2) Represents the estimated future payments under our oil and natural gas derivative contracts based on the future market prices as of December 31, 2014. These amounts will change as oil and natural gas commodity prices change.

Off Balance Sheet Arrangements

We do not have any off balance sheet arrangements, special purpose entities, financing partnerships or guarantees (other than our guarantee of our wholly owned subsidiary's credit facility).

Critical Accounting Policies and Estimates

Critical accounting policies are defined as those that are reflective of significant judgments and uncertainties and that could potentially result in materially different results under different assumptions and conditions. See Note B – Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report, for a discussion of additional accounting policies and estimates made by management.

Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U. S. ("GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting policies are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Reserve Estimates

Our estimates of proved oil and natural gas reserves constitute those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal of such contracts is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulation by governmental agencies, and assumptions governing future oil and natural gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic and therefore not includable in our reserve calculations. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and natural gas properties and/or the rate of depletion of such oil and natural gas properties.

Disclosure requirements under Staff Accounting Bulletin 113 ("SAB 113") include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. Pricing is based on a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves. In addition, the 12-month average is also used to measure ceiling test impairments and to compute depreciation, depletion and amortization.

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of

exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including dry hole costs, wells in progress, and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and natural gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated properties and our effective borrowing rate.

Capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and related deferred taxes, are limited to the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is an impairment charge to income and a write-down of oil and natural gas properties in the quarter in which the excess occurs.

Given the volatility of oil and natural gas prices, it is probable that our estimate of discounted future net cash flows from estimated proved oil and natural gas reserves will change in the near term.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

Derivative Hedging Instruments

We seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. The changes in the fair value of the derivative instruments are recorded in the income statement and included in sales of natural gas and crude oil.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX discount rates and price movements. The fair value of our commodity derivatives are calculated by our hedge counterparty and tested by an independent third party utilizing market-corroborated inputs that are observable over the term of the derivative contract.

50

Derivatives Associated with Preferred Stock

The Company issued Series A Preferred Stock on July 1, 2011 and Series B Preferred Stock in July and August of 2012. These shares of preferred stock had provisions with features of an option or derivative. Therefore, each quarter that these shares were outstanding required that this derivative liability be marked to fair value with the resulting changes recorded on the Consolidated Statement of Operations as "Change in fair value of preferred stock derivative liability – Series A and Series B." Since the Company was not public at the time, this determination of fair value was performed with the use of a Monte Carlo option pricing model by an outside consulting firm using level 3 inputs, along with management estimates of the probability of various events.

Goodwill

We account for goodwill in accordance with ASC 350, Intangibles—Goodwill and Other ("ASC 350"). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. We have one reporting unit. Goodwill recorded on our financial statements is related to the merger with Pyramid in 2014.

Accounting Standards Update ("ASU") No. 2011-08, Testing for Goodwill Impairment ("ASU 2011-08"), simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the entity is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying value of the reporting unit. If the carrying value exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of impairment loss, if any. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test.

Share-based Compensation

We have two types of long-term incentive awards – restricted stock awards (RSAs) and restricted stock units (RSUs). We account for them differently. RSUs are treated as a liability, although they are payable in either cash or stock at their vesting date, management intends to settle in cash, whereas RSAs are treated as equity since they are only payable in stock. The associated costs for RSUs are amortized as stock-based compensation over the life of the award. The costs associated with the RSAs are amortized from the point in time when the Company became public (RSAs had a performance-based requirement in order to vest).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this Item.

Item 8. Financial Statements and Supplementary Data.

The Report of the Independent Registered Public Accounting Firm and the Consolidated Financial Statements are set forth beginning on page F-1 of this Annual Report on Form 10-K and are included herein.

51

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures.

As previously reported on our Current Report on Form 8-K filed with the SEC on September 16, 2014 (the "prior 8-K"), on September 11, 2014, we dismissed our former independent registered public accounting firm and appointed Grant Thornton LLP as our independent registered public accounting firm for the 2014 fiscal year. For more information, please refer to the prior 8-K.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(e) and 15d-15(e), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were ineffective as of December 31, 2014 due to a material weakness in our internal control over financial reporting described below.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting of Yuma Energy, Inc. The Company's internal control system was designed to provide reasonable assurance to management and the Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting practices.

All internal control systems, no matter how well designed, have inherent limitations. Because of these inherent limitations, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation, and may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In the course of preparing of our annual report on Form 10-K for the year ended December 31, 2014, we concluded that a material weakness in internal control over financial reporting existed as of December 31, 2014 as described below.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented, or detected and corrected on a timely basis.

We made an error in the application of GAAP regarding the timing and recognition of stock-based compensation charges. Specifically, we did not devote adequate time with regard to analysis of this complex area of accounting. We lacked adequate controls regarding specific training in the relevant accounting guidance, review and documentation of this area of GAAP accounting in relation to complex stock based accounting transactions and review of related accounting disclosures.

Plan for Remediation of this Material Weakness. We intend to send a member of our staff to professional seminars on this particular area of compensation accounting. We are designing additional controls around identification, analysis, documentation and application of technical accounting guidance with particular emphasis on stock-based compensation. These controls are expected to include the implementation of additional supervision and review activities by qualified personnel, the preparation of formal accounting memoranda to support our conclusions on technical accounting matters, the development and use of checklists and research tools and consultation with compensation accounting experts to assist in compliance with GAAP with regard to stock based accounting issues. We intend to complete the implementation of our remediation plan during fiscal 2015.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the three month period ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

Item 11. Executive Compensation.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

Item 13. Certain Relationships, Related Transactions and Director Independence.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

Item 14. Principal Accounting Fees and Services.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

Form 10-K for the fiscal year ended December 31, 2014.

Exhibit No.	Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
1.1	At-the-Market Issuance Sales Agreement dated December 19, 2014 between Yuma Energy, Inc. and MLV & Co. LLC.	8-K	001-32989	1.1	December 29, 2014		
2.1	Amended and Restated Agreement and Plan of Merger and Reorganization dated as of August 1, 2014, by and among Yuma Energy, Inc., Pyramid Oil Company, Pyramid Delaware Merger Subsidiary, Inc., and Pyramid Merger Subsidiary, Inc.	8-K	001-32989	2.1(A)	August 4, 2014		
3.1	Restated Articles of Incorporation dated September 10, 2014.	8-K	001-32989	3.1	September 16, 2014		
3.2	Certificate of Determination of Rights, Preferences, Privileges and Restrictions of 9.25% Series A Cumulative Redeemable Preferred Stock of Yuma Energy, Inc.	8-A	001-32989	3.2	October 20, 2014		
3.3	Amended and Restated Bylaws of Yuma Energy, Inc.	S-3	333-192094	4.2	November 5, 2013		
10.1	Credit Agreement dated as of August 11, 2011, among Yuma Exploration and Production Company, Inc., as Borrower, Amegy Bank National Association, as Administrative Agent, and each of the lenders from time to time party thereto.	S-4	333-197826	10.3	August 4, 2014		
10.1(a)	First Amendment and Limited Waiver to Credit Agreement and	S-4	333-197826	10.4	August 4, 2014		

	Assignment effective as of September 21, 2012, among Yuma Exploration and Production Company, Inc., as Borrower, Amegy Bank National Association, as Administrative Agent and Assignor, Union Bank, N.A., as an Assignee and successor Administrative Agent and successor Issuing Bank, and each of the lenders party thereto.				
10.1(b)	Second Amendment to Credit Agreement and Assignment effective as of February 13, 2013, among Yuma Exploration and Production Company, Inc., as Borrower, Union Bank, N.A., as Administrative Agent and Assignor, Société Générale, as an Assignee and successor Administrative Agent and successor Issuing Bank, and each of the lenders party thereto.	S-4	333-197826	10.5	August 4, 2014
10.1(c)	Third Amendment to Credit Agreement and Assignment effective as of May 20, 2013, among Yuma Exploration and Production Company, Inc., as Borrower, Union Bank, N.A., as Assignor, Société Générale, as an Assignor and Administrative Agent and Issuing Bank, OneWest Bank, FSB, as Assignee, and each of the lenders party thereto.	S-4	333-197826	10.6	August 4, 2014
10.1(d)	Fourth Amendment to Credit Agreement effective as of April 22, 2014, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as Administrative Agent and Issuing Bank, and each of the lenders party thereto.	S-4	333-197826	10.7	August 4, 2014
10.1(e)	Fifth Amendment to Credit Agreement effective as of	8-K	001-32989	10.1	October 14, 2014

	October 14, 2014, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as Administrative Agent and Issuing Bank, and each of the lenders party thereto.

10.1(f)	Sixth Amendment to Credit Agreement effective as of January 23, 2015, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as Administrative Agent and Issuing Bank, and each of the lenders party thereto.	8-K	001-32989	10.1	January 29, 2014
10.2†	Employment Agreement dated October 1, 2012, between Yuma Energy, Inc. and Sam L. Banks.	S-4	333-197826	10.8	August 4, 2014
10.3†	Employment Agreement dated October 1, 2012, between Yuma Energy, Inc. and Michael F. Conlon.	S-4	333-197826	10.9	August 4, 2014
10.4†	Employment Agreement dated June 15, 2014, between Yuma Energy, Inc. and Mark D. Hartman.	S-4	333-197826	10.10	August 4, 2014
10.5	Form of Indemnification Agreement.	8-K	001-32989	10.1	September 16, 2014
10.6†	Employment Agreement dated June 1, 2012, between Yuma Energy, Inc. and Kirk F. Sprunger.	8-K	001-32989	10.4	September 16, 2014
10.7†	2006 Equity Incentive Plan of the Registrant.	S-8	333-175706	4.3	July 21, 2011
10.8†	Yuma Energy, Inc. 2011 Stock Option Plan.	8-K	001-32989	10.5	September 16, 2014
10.9†	Yuma Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-32989	10.6	September 16, 2014
10.10†	Employment Agreement dated October 15, 2014 between Yuma Energy, Inc. and Paul D. McKinney.	10-Q	001-32989		November 14, 2014
10.11†	Separation Agreement and General Release of Claims dated December 25, 2014, between Yuma Energy, Inc. and Michael F. Conlon.	8-K	001-32989	10.1	December 29, 2014
10.12†	Employment Agreement of John H. Alexander, dated February 21, 2002.	10-QSB	001-32989	10.4	March 29, 2002

10.13†	Severance Award Agreement of John H. Alexander, dated January 9, 2007.	8-K	001-32989	99.1	January 16, 2007
10.14†	Severance Award Agreement of John H. Alexander, dated December 30, 2008.	8-K	001-32989	10.1	January 6, 2008
10.15†	Severance Award Agreement of John H. Alexander, dated June 4, 2009.	10-K	001-32989	10.4	March 30, 2011
10.16†	Severance Award Agreement of John H. Alexander, dated September 21, 2010.	10-Q	001-32989	10.1	November 12, 2010
10.17	Settlement Agreement and General Release of All Claims, dated as of September 30, 2013, between the Registrant and John H. Alexander.	8-K	001-32989	10.1	October 4, 2013
10.18	Trust Agreement, dated as of October 1, 2013, between the Registrant and Gilbert Ansolabehere, as trustee.	8-K	001-32989	10.2	October 4, 2013
10.19	Consulting Agreement, dated as of October 1, 2013, between the Registrant and John H. Alexander.	8-K	001-32989	10.3	October 4, 2013

10.20	Indemnity Agreement, dated as of September 30, 2013, between the Registrant and John H. Alexander.	8-K	001-32989	10.4	October 4, 2013		
10.21	Indemnity Agreement, dated as of January 7, 2014, between the Registrant and Gary L. Ronning.	10-K	001-32989	10.10	March 31, 2014		
10.22	Indemnity Agreement, dated as of January 7, 2014, between the Registrant and Michael D. Herman.	10-K	001-32989	10.11	March 31, 2014		
10.23	Indemnity Agreement, dated as of January 7, 2014, between the Registrant and Rick D. Kasch.	10-K	001-32989	10.12	March 31, 2014		
10.24†	Amendment No. 1 dated March 12, 2015 to the Employment Agreement between Yuma Energy, Inc. and Paul D. McKinney.	8-K	001-32989	10.1	March 17, 2015		
14	Code of Ethics.	8-K	001-32989	14	September 16, 2014		
21.1	List of Subsidiaries.					X	
23.1	Consent of Grant Thornton LLP.					X	
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
31.1	Certification of the Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X	
31.2	Certification of the Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X	
32.1	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X
32.2	Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	

101.INS	XBRL Instance Document.	X
101.SCH	XBRL Schema Document.	X
101.CAL	XBRL Calculation Linkbase Document.	X
101.DEF	XBRL Definition Linkbase Document.	X
101.LAB	XBRL Label Linkbase Document.	X
101.PRE	XBRL Presentation Linkbase Document.	X

† Indicates management contract or compensatory plan or arrangement.

SIGNATURES

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

YUMA ENERGY, INC.

	By:	/s/ Sam L. Banks
	Name:	Sam L. Banks
Date: March 30, 2015	Title:	President and Chief Executive Officer (Principal Executive Officer)

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

Signature	Title	Date
/s/ Sam L. Banks Sam L. Banks	Chairman of the Board, Director, President and Chief Executive Officer (Principal Executive Officer)	March 30, 2015
/s/ Kirk F. Sprunger Kirk F. Sprunger	Chief Financial Officer, Treasurer and Corporate Secretary (Principal Financial Officer and Principal Accounting Officer)	March 30, 2015
/s/ James W. Christmas James W. Christmas	Director	March 30, 2015
/s/ Frank A. Lodzinski Frank A. Lodzinski	Director	March 30, 2015
/s/ Ben T. Morris Ben T. Morris	Director	March 30, 2015
/s/ Richard K. Stoneburner Richard K. Stoneburner	Director	March 30, 2015
/s/ Richard W. Volk Richard W. Volk	Director	March 30, 2015

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Yuma Energy, Inc.

We have audited the accompanying consolidated balance sheets of Yuma Energy, Inc. (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Yuma Energy, Inc. as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas
March 30, 2015

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,558,322	$4,194,511
Short-term investments	1,170,868	-
Accounts receivable, net of allowance for doubtful accounts:		
Trade	9,739,737	10,837,211
Officers and employees	316,077	155,080
Other	697,991	417,850
Commodity derivative instruments	3,338,537	-
Prepayments	782,234	433,991
Deferred taxes	245,922	146,964
Other deferred charges	342,798	162,416
Total current assets	28,192,486	16,348,023
OIL AND GAS PROPERTIES (full cost method):		
Not subject to amortization	25,707,052	24,051,278
Subject to amortization	186,530,863	152,863,988
	212,237,915	176,915,266
Less: accumulated depreciation, depletion and amortization	(103,929,493)	(84,438,840)
Net oil and gas properties	108,308,422	92,476,426
OTHER PROPERTY AND EQUIPMENT:		
Land, buildings and improvements	2,795,000	-
Other property and equipment	3,439,688	2,066,760
	6,234,688	2,066,760
Less: accumulated depreciation and amortization	(1,909,352)	(1,822,925)
Net other property and equipment	4,325,336	243,835
OTHER ASSETS AND DEFERRED CHARGES:		
Commodity derivative instruments	1,403,109	818,637
Deposits	264,064	7,300
Receivables from affiliate	-	95,634
Goodwill	5,349,988	-
Other noncurrent assets	262,200	1,642,113
Total other assets and deferred charges	7,279,361	2,563,684
Total assets	$148,105,605	$111,631,968

The accompanying notes are an integral part of these financial statements.

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS - CONTINUED

	December 31,	
	2014	2013
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of debt	$282,843	$178,027
Accounts payable, principally trade	25,004,364	15,116,560
Commodity derivative instruments	-	677,132
Asset retirement obligations	-	1,755,650
Deferred taxes	471,995	-
Other accrued liabilities	1,419,565	1,127,283
Total current liabilities	27,178,767	18,854,652
LONG-TERM DEBT:		
Bank debt	22,900,000	31,215,000
OTHER NONCURRENT LIABILITIES:		
Preferred stock derivative liability, Series A and B	-	51,290,414
Asset retirement obligations	12,487,770	8,942,029
Commodity derivative instruments	-	218,649
Deferred taxes	14,388,662	13,160,205
Restricted stock units	71,569	102,532
Other	22,451	69,998
Total other noncurrent liabilities	26,970,452	73,783,827
PREFERRED STOCK:		
Series A and B, subject to mandatory redemption	-	35,666,342
EQUITY:		
Common stock, no par value		
(300 million shares authorized, 69,139,869 and 41,074,950 issued)	137,469,772	2,669,465
Preferred stock	9,958,217	-
Accumulated other comprehensive income	38,801	38,770
Accumulated earnings (deficit)	(76,410,404)	(50,596,088)
Total equity	71,056,386	(47,887,853)
Total liabilities and equity	$148,105,605	$111,631,968

The accompanying notes are an integral part of these financial statements.

F-4

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2014	2013	2012
REVENUES:			
Sales of natural gas and crude oil	$42,057,910	$28,075,603	$21,282,115
Other revenue	1,278,217	1,066,969	601,794
Total revenues	43,336,127	29,142,572	21,883,909
EXPENSES:			
Marketing cost of sales	1,045,177	1,234,308	891,118
Lease operating	12,816,725	9,316,364	5,098,868
Re-engineering and workovers	3,084,972	2,521,707	433,599
General and administrative – stock-based compensation	3,388,321	452,058	-
General and administrative – other	9,434,294	5,603,475	4,339,362
Depreciation, depletion and amortization	19,664,991	12,077,368	5,074,070
Asset retirement obligation accretion expense	604,511	668,497	265,323
Other	98,476	171,774	151,240
Total expenses	50,137,467	32,045,551	16,253,580
INCOME (LOSS) FROM OPERATIONS	(6,801,340)	(2,902,979)	5,630,329
OTHER INCOME (EXPENSE):			
Change in fair value of preferred stock derivative liability - Series A and Series B	(15,676,842)	(26,258,559)	(17,098,504)
Interest expense	(326,200)	(567,676)	(210,083)
Other, net	25,378	(240,617)	7,099
Total other income (expense)	(15,977,664)	(27,066,852)	(17,301,488)