Yuma Energy, Inc.
Form 10-K
March 30, 2016

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

FORM 10-K

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

For the fiscal year ended December 31, 2015

oTRANSITION 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 (State or other jurisdiction of incorporation or organization)	94-0787340 (IRS Employer Identification No.)
1177 West Loop South, Suite 1825 Houston, Texas (Address of principal executive offices)	77027 (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 x 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 x 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. x 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). ý Yes ¨ 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. x

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 o (Do not check if a smaller reporting company) Smaller reporting company x

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

The aggregate market value on June 30, 2015, (the last business day of the registrant's most recently completed second fiscal quarter) of the voting shares held by non-affiliates was approximately $14,956,252 based on the closing sales price of the registrant's common stock on the NYSE MKT on such date.

At March 29, 2016, 71,911,361 shares of the Registrant's common stock, no par value, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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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 thereo 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 Item 1A. "Risk Factors" 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:

- our ability to repay outstanding loans when due;
- our limited liquidity and ability to finance our exploration, acquisition and development strategies;
- reductions in the borrowing base under our credit facility;
- impacts to our financial statements as a result of oil and natural gas property impairment write-downs;
- 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;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and seek to 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 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 our 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 we expect, 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 section and elsewhere in this document. Other than as required under applicable 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

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

“3-D” means three-dimensional.

“Bbl” or “Bbls” means barrel or barrels of oil or natural gas liquids.

“Bbl/d” means Bbl per day.

“Boe” means barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.

“Boe/d” means Boe per day.

“Btu” means a British thermal unit, a measure of heating value.

“HH” means Henry Hub natural gas spot price.

“HLS” means Heavy Louisiana Sweet crude spot price.

“LIBOR” means London Interbank Offered Rate.

“LLS” means Argus Light Louisiana Sweet crude spot price.

“LNG” means liquefied natural gas.

“MBbls” means thousand barrels of oil or natural gas liquids.

“MBoe” means thousand Boe.

“Mcf” means thousand cubic feet of natural gas.

“Mcf/d” means Mcf per day.

“MMBtu” means million Btu.

“MMBtu/d” means MMBtu per day.

“MMcf” means million cubic feet of natural gas.

“MMcf/d” means MMcf per day.

“NGL” or “NGLs” means natural gas liquids, which are expressed in barrels.

“NYMEX” means New York Mercantile Exchange.

“oil” includes crude oil and condensate.

“PUD” means proved undeveloped.

“SEC” means the United States Securities and Exchange Commission.

“U.S.” means the United States of America.

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

Item 1. Business.

Overview

Unless the context otherwise requires, all references in this report to the "Company," "Yuma," "our," "us," and "we" refer to Yuma Energy, Inc. (formerly known as Pyramid Oil Company) and its subsidiaries, as a common entity. Unless otherwise noted, all information in this 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 referenced certain technical terms important to an understanding of our business under the Glossary of Selected Oil and Natural Gas Terms section above. Throughout this 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 an independent Houston-based exploration and production company with approximately 13.3 million Boe of proved reserves as of December 31, 2015. We are focused on the acquisition, development, and exploration for conventional and unconventional oil and natural gas resources, primarily 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 assets located in central and southern 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. 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."

Recent Developments

Agreement and Plan of Merger and Reorganization

On February 10, 2016, the Company and privately held Davis Petroleum Acquisition Corp. ("Davis") entered into a definitive merger agreement for an all-stock transaction. Upon completion of the transaction, we will reincorporate in Delaware, implement a one-for-ten reverse split of our common stock, and convert each share of our existing Series A Preferred Stock into 35 shares of common stock prior to giving effect for the reverse split (3.5 shares post reverse split). Following these actions, we will issue additional shares of common stock in an amount sufficient to result in approximately 61.1% of the common stock being owned by the current common stockholders of Davis. In addition, we will issue approximately 3.3 million shares of a new Series D preferred stock to existing Davis preferred stockholders, which is estimated to have a conversion price of approximately $5.70 per share, after giving effect for the reverse split. The Series D preferred stock is estimated to have an aggregate liquidation preference of approximately $18.7 million at closing, and will be paid dividends in the form of additional shares of Series D preferred stock at a rate of 7% per annum. Upon closing, there will be an aggregate of approximately 23.7 million shares of our common stock outstanding (after giving effect to the reverse stock split and conversion of Series A Preferred Stock to common stock). The transaction is expected to qualify as a tax-deferred reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended (the "Code").

The merger agreement is subject to the approval of the shareholders of both companies, as well as other customary approvals, including authorization to list the newly issued shares on the NYSE MKT. The parties anticipate completing the transaction in mid-2016.

Davis is a Houston-based oil and gas company focused on the acquisition, exploration and development of domestic oil and gas properties. Over 90% of the common stock of Davis is owned by entities controlled by or co-investing with Evercore Capital Partners, Red Mountain Capital Partners, and Sankaty Advisors. These major stockholders purchased the predecessor company from the family of Marvin Davis in 2006. Davis' company-operated properties are conventional fields located onshore in south Louisiana and the upper Texas Gulf Coast, and its non-operated properties include Eagle Ford and Woodbine properties in east Texas.

Upon closing, four of the five current Yuma Board members will continue to serve on the combined company Board. Richard K. Stoneburner will serve as Non-Executive Chairman, and Sam L. Banks will continue to serve as Director, President and Chief Executive Officer. James W. Christmas and Frank A. Lodzinski will also continue to serve. Three additional Directors will be nominated by Davis, bringing the size of the new Board to seven, and the Board will meet the director independence requirements of the NYSE MKT. All current officers of Yuma will serve in their same capacity in the combined company.

Amendment to Senior Credit Agreement

On December 30, 2015, we entered into the Waiver, Borrowing Base Redetermination and Ninth Amendment (the “Amendment”) to our Credit Agreement (the “credit agreement”) with Société Générale (the “Bank”) as administrative agent and issuing bank, and each of the lenders and guarantors party thereto. Pursuant to the Amendment, the borrowing base under the credit agreement was reduced from $35.0 million to $29.8 million and will automatically be reduced to $20.0 million on May 31, 2016 unless otherwise reduced by or to a different amount by the lenders under the credit agreement. The Amendment also provided a waiver of the financial covenant related to the maximum permitted ratio of funded debt to EBITDA for the fiscal quarter ended September 30, 2015 and any failure to comply with that financial covenant and certain other financial covenants for the fiscal quarter ended December 31, 2015. Pursuant to the Amendment, we agreed that on or before February 6, 2016, we will engage an investment bank to explore strategic options for our finances and, on or before March 31, 2016, we will either enter into an underwritten commitment for additional capital in an aggregate amount sufficient for us to pay any borrowing base deficiency then existing or enter into a definitive agreement for the acquisition by a third party of all or substantially all of our assets by merger, asset purchase, equity purchase or other structure acceptable to the Bank and the lenders. Thereafter, on February 10, 2016, we entered into the merger agreement with Davis as discussed above, and we expect to enter into another amendment to the credit agreement to account for the contemplated merger with Davis.

In addition, the Amendment to the credit agreement 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 $29.8 million through May 31, 2016 and thereafter the borrowing base will automatically be reduced to $20.0 million unless otherwise reduced by or to a different amount by the lenders under the credit agreement. The credit agreement is secured by a first lien on substantially all of our assets. As of March 29, 2016, the borrowing base was $29.8 million and the debt outstanding was $29.8 million. Amounts borrowed under the credit agreement bear interest at either (a) LIBOR plus 2.25% to 3.25% or (b) the prime rate plus 1.25% to 2.25%, 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 our 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. For the fiscal quarters ended September 30, 2015 and December 31, 2015, we were not in compliance with certain financial ratio covenants in the credit agreement; however, we received a waiver from the lenders under the credit agreement pursuant to the Amendment. See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 3 – Liquidity Considerations and Note 13 – Debt and Interest Expense.

Issuance of 9.25% Series A Cumulative Redeemable Preferred Stock

In October 2014, 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 $10,430,894, net of the underwriters’ discount and underwriters’ expenses. During the year ended December 31, 2015, we sold 46,857 shares of Series A Preferred Stock with aggregate net proceeds of $870,386, net of underwriters’ discount and underwriters’ expenses under an At-the-Market Issuance Sales Agreement (see below).

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 shares of our Series A Preferred Stock and shares of our common stock. The offer and sale of these shares was registered under a 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. During the year ended December 31, 2015, we sold 46,857 shares of Series A Preferred Stock and 1,347,458 shares of our common stock under the sales agreement.

Operating Outlook

During 2015, the oil and natural gas industry experienced significant decreases in commodity prices driven by supply and demand imbalances for oil internationally and for natural gas in the United States. The decline in commodity prices and global economic conditions have continued into 2016, and low commodity prices may exist for an extended period of time.

We plan to continue our disciplined approach in 2016 by emphasizing liquidity and value over growth, enhancing operational efficiencies, and reducing capital expenses. We will continue to evaluate the oil and natural gas price environments and may adjust our capital spending plans, capital raising activities, and strategic alternatives (including possible asset sales) to maintain appropriate liquidity and financial flexibility.

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 acquisitions, mergers, exploration and the development of our Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex, Hackberry, Bakken, Three Forks, and Monterey Shale acreage.

The key elements of our business strategy are:

» seek merger and acquisition opportunities to increase the Company’s liquidity, as well as reduce G&A on a per Boe basis to the Company;

» transition existing inventory of reserves into oil and natural gas production;

» add selectively to project inventory through ongoing prospect generation, exploration and strategic acquisitions; and

» retain a greater percentage working interest in, and operatorship of, our projects going forward.

» Our core competencies include oil and natural gas operating activities and expertise in generating:

» unconventional oil resource plays;

» onshore liquids-rich prospects through the use of 3-D seismic surveys; and

» 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 are our key strengths and competitive advantages:

» 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. We believe 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.

» 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.

» Liquids-rich, quality assets with attractive economics. Our assets and potential future drilling locations are primarily in oil plays with associated liquids-rich natural gas.

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

» Significant inventory of oil and natural gas assets. We have an 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.

» 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.

» 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.

» 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 78% of our proved oil and natural gas reserves as of December 31, 2015. 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 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 Area, 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, 2015, we held approximately 61,986 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 we hold interest in approximately 22 operated proved undeveloped locations, three non-operated proved undeveloped locations, 63 operated non-proved undeveloped locations, and 11 non-operated non-proved undeveloped locations that are either held by production or contain existing leasehold. We are currently seeking joint venture partners to participate in the future drilling and development of these locations, which would reduce our participating interest in these locations and thereby reduce our future capital expenditures and associated proved and non-proved reserves and production. We plan to drill one proved undeveloped well this year and the remaining proved undeveloped wells within five years from the date they were originally recorded.

During the first quarter of 2016, we shut-in 14 Austin Chalk wells in Beauregard, Rapides and Vernon Parishes, Louisiana due to low oil and natural gas prices. If we do not restart production from these wells, the associated leases will expire reducing our proved reserves by approximately 1,629 MBoe, our acreage by 22,021 gross (18,140 net) acres, our operated proved undeveloped locations by three, and our operated non-proved undeveloped locations by seven.

During the first quarter of 2016, we received notice from the operator of certain wells in Rapides and Vernon Parishes, Louisiana, that certain wells in which we have an interest were shut-in due to current economic conditions. The operator plans to sell its interest. If the operator does not restart production from these wells or if a subsequent operator does not restart production from these wells, the associated leases will expire, which would reduce our proved reserves by approximately 285 MBoe, our acreage by 18,895 gross (3,737 net) acres, our non-operated proved undeveloped locations by three, and our non-operated non-proved undeveloped locations by 18.

We are currently negotiating with a certain mineral owner to amend the oil and gas lease agreement to extend the expiration date of certain acreage that is not held by production as of March 29, 2016. The total acreage is approximately 25,139 acres which will expire July 1, 2016 unless we initiate drilling of a development well on the pooled lands or pay a deferred development payment by July 1, 2016. If the leased acreage expires, our proved reserves would be reduced by approximately 5,096 MBoe, the number of operated proved undeveloped locations and operated non-proved locations would be reduced by 13 and 16, respectively.

This field is highly material to our future results of operations and financial position. For further information on this development project, see Item 1A. “Risk Factors.”

La Posada – Bayou Hebert Field, Vermilion Parish, Louisiana. We have a 12.5% non-operated working interest in La Posada (Bayou Hebert) Field which is comprised of three wells producing from the Lower Planulina Cris R sands, and approximately 1,600 gross acres (200 net acres). In 2016, the operator may recomplete one or more wells to up-hole Cris R zones. The field averaged approximately 50.1 MMcf/d of natural gas and 950 Bbl/d of oil gross (4.5 MMcf/d and 85 Bbl/d net) during the month of December 2015.

Livingston – Beaver Dam Creek Field, Bills Branch Field, Livingston North Field, St. Helena and Livingston Parishes, Louisiana. We operate four wells producing oil from the lower Tuscaloosa sands, three wells producing from the Wilcox sands, and one salt water disposal well. We hold an average working interest of 39% in these wells. 2015 operational activities focused on increasing oil production and profitability by installing and optimizing artificial lift systems and reducing operating costs. The average daily production from the seven producing wells during December 2015 was approximately 558 Bbl/d of oil gross (156 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%. Throughout December 2015, production levels in the field averaged approximately 118 Bbl/d of oil gross (77 Bbl/d net).

Gardner Island and Branville Bay, St. Bernard Parish, Louisiana. We hold an average working interest of 36% in 1,344 gross acres (484 net acres). Throughout December 2015, production levels in the field averaged approximately 359 Bbl/d of oil gross (97 Bbl/d net).

Kern County Field Area, Kern County, California. We hold 100% working interest in 960 gross lease acres and 244 fee acres in Kern County, California. We operate seven fields producing from Pliocene, Miocene, Oligocene, and Eocene age reservoirs from relatively shallow depths. These assets are characterized by long-life shallow decline production. For the month ended December 31, 2015, production totaled 145 Bbls of oil per day gross (123 Bbl/d net).

Livingston 3-D Project, St. Helena and Livingston Parishes, Louisiana. In 2009 and 2010, we shot a 138 square mile 3-D seismic survey targeting the intermediate depth Wilcox sands at approximately 10,000 feet deep and the deeper lower Tuscaloosa sands at approximately 15,000 feet. We hold an average working interest of 39% across 3,292 gross (1,973 net) lease option acres in the Livingston 3-D Project area and we are the operator and have access rights to drill additional exploration wells to both the Lower Tuscaloosa and the Wilcox oil sands, the future drilling of which are dependent on economic conditions.

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 do not plan to drill any new wells in the Amazon 3-D Project in 2016.

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 has produced 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 149 acres 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 2016.

Bakken – Yellowstone and Southeast Homerun, McKenzie County, North Dakota. At December 31, 2015, we held an average 4.6% non-operated working interest in 18,553 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. For the month ended December 31, 2015, gross production totaled 427 Boe per day (14 Boe/d net). We currently estimate that significant future infill Bakken and Three Forks development upside potential exists on our acreage, the development of which will be influenced largely by future oil and natural gas commodities prices.

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 25 – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited) 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 2015 other than to the SEC.

Estimated Proved Reserves

The table below summarizes our estimated proved reserves at December 31, 2015 based on reports prepared by NSAI. In preparing these reports, NSAI evaluated 100% of our properties at December 31, 2015. 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.

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	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)	204	26	269	275	$ (792)
La Posada (Bayou Hebert) Field (4)	129	221	5,735	1,305	$ 17,589
Other	1,469	69	2,549	1,963	$ 27,275
Total proved developed	1,802	316	8,553	3,543	$ 44,072
Proved undeveloped (3)					
Greater Masters Creek Field (4)	4,398	1,585	13,164	8,177	$ 65,967
La Posada (Bayou Hebert) Field (4)	76	150	3,898	876	$ 6,881
Other	640	0	155	665	$ 5,988
Total proved undeveloped	5,114	1,735	17,217	9,718	$ 78,836
Total proved (3)	6,916	2,051	25,770	13,261	$ 122,908

(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 includes estimated abandonment costs less salvage. 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 25 – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited) 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, 2015:

Present value of estimated future net revenues (PV10)	$122,908
Future income taxes discounted at 10%	(16,845)
Standardized measure of discounted future net cash flows	$106,063

(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 $50.28 per Bbl (WTI) and $2.59 per MMBtu (HH), for the year ended December 31, 2015. Adjustments were made for location and grade.

(4) Our Greater Masters Creek Field and La Posada (Bayou Hebert) field were our only fields that each contained 15% or more of our estimated proved reserves as of December 31, 2015.

We have stress-tested our proved reserve estimates as of December 31, 2015 to determine the impact of lower crude oil and natural gas prices. Replacing the twelve-month unweighted arithmetic average commodity prices used in estimating our reported proved reserves (see Note 25 – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited) in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report) with those shown on the table below, and leaving all other parameters unchanged, results in a decrease in our estimated proved reserves as shown below.

	Pricing Scenario			
	Crude Oil (per Bbl) (1)	Natural Gas (per MMBtu) (1)	Proved Reserves (MBoe)	% Change from December 31, 2015 Estimated Reserves
2015 Reserve Report (2)	$50.28	$2.59	13,261	-
Scenario A	$40.00	$2.25	12,876	(3 %)
Scenario B	$30.00	$2.00	9,358	(29 %)

(1) These prices are indices and do not include basin differentials for crude oil and natural gas. The above scenarios were calculated using the indicated index prices, less any basin differentials, transport fees, contractual adjustments and any Btu adjustments we experienced for the respective commodity.

(2) The NYMEX prices used for our 2015 year-end independent engineering reserve report are based on SEC price parameters using the twelve-month unweighted arithmetic average of the first-day-of-the-month prices for each of the preceding twelve months for the year ended December 31, 2015.

Proved Undeveloped Reserves

At December 31, 2015, our estimated proved undeveloped ("PUD") reserves were approximately 9,718 MBoe. The following table details the changes in PUD reserves for the year ended December 31, 2015 (in MBoe):

Beginning proved undeveloped reserves at January 1, 2015	16,243
Undeveloped reserves transferred to developed	(100)
Purchases of minerals-in-place	43
Extensions and discoveries	459
Production	0
Revisions	(6,927)
Proved undeveloped reserves at December 31, 2015	9,718

From January 1, 2015 to December 31, 2015, our PUD reserves decreased 40.2% from 16,243 MBoe to 9,718 MBoe, or a decrease of 6,525 MBoe. Reserves of 100 MBoe were moved from the PUD reserve category to the proved developed producing category through the drilling of the Talbot 23-1 well. We incurred approximately $3.2 million in capital expenditures during the year ended December 31, 2015 in converting this well to the proved developed reserve category. We acquired 43 MBoe through purchases of minerals-in-place and added 459 MBoe through extensions of existing discoveries. The remaining change to our year-end 2015 PUDs of 6,927 MBoe was a result of downward revisions due to price of 4,293 MBoe, upward performance revisions of 1,829 MBoe, and downward revision due to reclassifying 4,463 MBoe of Greater Masters Creek Field Area undeveloped reserves to non-proved due to the depressed price environment and expected effect on the Company's access to capital and drilling plans. As of December 31, 2015, we plan to drill all of our PUD drilling locations within five years from the date they were initially recorded.

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 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, 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 Executive Vice President and Chief Operating Officer is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for overseeing the independent petroleum engineering firm during the preparation of our reserve report. He has a Bachelor of Science degree in Petroleum Engineering and over 30 years of industry experience, with 20 years or more of experience working as a reservoir engineer, reservoir engineering manager, or reservoir engineering executive. His professional qualifications meet or exceed 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. The Executive Vice President and Chief Operating Officer reports directly to our Chief Executive Officer.

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, geologists, and 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 Chief Operating Officer and our reservoir engineering staff. 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 is performed between NSAI and us, and additional data is provided to address any 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, 2015, 2014 and 2013, the average sales price per unit sold and the average production cost per unit are presented below.

	Years Ended December 31,		
	2015	2014	2013
Production volumes:			
Crude oil and condensate (Bbls)	247,177	231,816	184,349
Natural gas (Mcf)	1,993,842	2,714,586	1,580,468
Natural gas liquids (Bbls)	74,511	97,783	51,875
Total (Boe) (1)	653,995	782,030	499,635
Average prices realized:			
Excluding commodity derivatives:			
Crude oil and condensate (per Bbl)	$48.07	$93.98	$104.26
Natural gas (per Mcf)	$2.60	$4.62	$3.83
Natural gas liquids (per Bbl)	$18.89	$38.44	$40.17
Including commodity derivatives:			
Crude oil and condensate (per Bbl)	$65.20	$101.98	$104.39
Natural gas (per Mcf)	$3.00	$5.19	$3.71
Natural gas liquids (per Bbl)	$18.89	$38.44	$40.17
Production cost per Boe (2)	$13.22	$11.60	$12.40

(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 $2,758,207, $3,741,513, and $3,121,185 in fiscal years 2015, 2014 and 2013, respectively.

Effective January 1, 2013, we acquired our interest in the Greater Masters Creek Field Area, which contained 64%, 79% and 78% of our total proved reserves as of December 31, 2015, 2014 and 2013, respectively. Our interests in La Posada (Bayou Hebert) field represented 16% of our total proved reserves as of December 31, 2015. No other single field accounted for 15% or more of our proved reserves as of December 31, 2015, 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, 2015, 2014 and 2013, the average sales price per unit sold and the average production cost per unit for the Greater Masters Creek Field Area are presented below.

	Years Ended December 31,		
Greater Masters Creek Field Area	2015	2014	2013
Production volumes:			
Crude oil and condensate (Bbls)	27,379	45,656	24,972
Natural gas (Mcf)	102,309	170,916	85,866
Natural gas liquids (Bbls)	8,192	16,558	8,702
Total (Boe) (1)	52,623	90,700	47,985
Average prices realized: (2)			
Crude oil and condensate (per Bbl)	$47.29	$95.29	$100.87
Natural gas (per Mcf)	$2.59	$4.68	$4.07
Natural gas liquids (per Bbl)	$15.21	$33.67	$34.98
Production cost per Boe (3)	$48.39	$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 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 $934,131, $1,111,162, and $875,488 in fiscal years 2015, 2014 and 2013, respectively.

The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the year ended December 31, 2015, the average sales price per unit sold and the average production cost per unit for our La Posada (Bayou Hebert) field are presented below.

La Posada (Bayou Hebert) Field	Year Ended December 31, 2015
Production volumes:	
Crude oil and condensate (Bbls)	32,950
Natural gas (Mcf)	1,645,202
Natural gas liquids (Bbls)	58,913
Total (Boe) (1)	366,063
Average prices realized: (2)	
Crude oil and condensate (per Bbl)	$49.40
Natural gas (per Mcf)	$2.62
Natural gas liquids (per Bbl)	$19.99
Production cost per Boe (3)	$3.91

(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 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, 2015, 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
130	90	47	3	177	93

(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, 2015, 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	77,589	33,962	32,459	31,899	110,048	65,861
North Dakota	18,553	674	-	-	18,553	674
Texas	1,036	72	80	68	1,116	140
Oklahoma	2,160	96	-	-	2,160	96
California	1,422	1,400	-	-	1,422	1,400
Wyoming	7,360	3	-	-	7,360	3
Total	108,120	36,207	32,539	31,967	140,659	68,174

As of December 31, 2015, we had leases representing 24,377 net acres (24,141 of which were in the Greater Masters Creek Field Area) expiring in 2016; 7,514 net acres (6,219 of which were in the Greater Masters Creek Field Area) expiring in 2017; and 76 net acres (10 of which were in the Greater Masters Creek Field Area) expiring in 2018 and beyond. We believe that our current and future drilling plans, along with selected lease extensions, can address the majority of the leases expiring in the Greater Masters Creek Field Area and our other fields in 2016 and beyond. As disclosed earlier in this report, during the first quarter of 2016, we received notice from the operator of certain Greater Masters Creek Field Area wells that they had shut-in certain wells in which we have an interest due to current economic conditions. If production is not restarted from these wells, the associated leases will expire, which would reduce our acreage by 18,895 gross (3,737 net) acres. Additionally, during the first quarter of 2016, we shut-in 14 Greater Masters Creek Field Area wells due to low oil and natural gas prices. If we do not restart production from these wells, the associated leases will expire reducing our acreage by 22,021 gross (18,140 net) acres. Finally, we are currently negotiating with a certain mineral owner to amend the oil and gas lease agreement to extend the expiration date of certain acreage that, as of March 29, 2016, was not held by production. The total acreage is approximately 25,139 net acres which will expire July 1, 2016 unless we initiate drilling of a development well on the pooled lands or pay a deferred development payment by July 1, 2016.

Exploratory Wells and Development Wells

Set forth below for the years ended December 31, 2015, 2014 and 2013 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
2015	-	-	.51	-	.51
2014	.61	-	.54	-	1.15
2013	.32	-	.57	.31	1.20

Present Activities

At March 29, 2016, we had 0 gross (0 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, Basic Sediment and Water (“BS&W”) and transportation. Generally, the index or posting is based on West Texas Intermediate (“WTI”) and adjusted to Light Louisiana Sweet (“LLS”) or Heavy Louisiana Sweet (“HLS”). For the years ended December 31, 2015, 2014 and 2013, the LLS postings averaged $3.48, $3.02, and $9.58 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 than us. 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, and hiring and retaining key employees. There is also competition among 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 U.S. government 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.

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. In 2015, three individual purchasers of our production, PetroQuest Energy, LLC, GulfMark Energy, Inc. and Genesis Crude Oil, LP accounted for 67% of our total sales for the year.

In 2014, three individual purchasers of our production, PetroQuest Energy, LLC, GulfMark Energy, Inc. and Gavilon, LLC accounted for 73% of our total sales for the year.

In 2013, four individual purchasers of our production, PetroQuest Energy, LLC, GulfMark Energy, Inc., Hilcorp Energy Company and Genesis Crude Oil, L. P., accounted for 78% 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 belief, 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 October 2015, the EPA issued a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The final rule became effective in December 2015. Certain areas of the country in compliance with the ground-level ozone NAAQS standard may be reclassified as non-attainment and such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement more stringent regulations, which could apply to our operations. Compliance with this final rule could, among other things, require installation or new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating 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 August 2015, the EPA proposed rules that will establish emission standards for methane from certain new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA's proposed rule package includes standards to address emissions of methane from equipment and processes across the source category, including hydraulically-fractured oil and natural gas well completions, fugitive emissions from well sites and compressors, and equipment leaks at natural gas processing plants and pneumatic pumps. The EPA is expected to finalize these rules in 2016.

The U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes, and GHG reporting and tracking programs. In the absence of federal GHG-limiting legislations, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets.

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, 2015, we had 30 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, 2015, 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 (three town lots).

Executive Officers of the Company

The following table sets forth the names and ages of all of our executive officers, the positions and offices with us held by such persons and the months and years in which continuous service as executive officers began:

Name	Executive Officer Since	Age	Position
Sam L. Banks	September 2014	66	Chairman of the Board, President and Chief Executive Officer
James J. Jacobs	December 2015	38	Chief Financial Officer, Treasurer and Corporate Secretary
Paul D. McKinney	October 2014	57	Executive Vice President and Chief Operating Officer

The following paragraphs contain certain information about each of our executive officers.

Sam L. Banks has been our Chief Executive Officer and Chairman of the Board of Directors since the closing of the merger on September 10, 2014 and also our President since October 10, 2014. He was the Chief Executive Officer and Chairman of the board of directors of Yuma Co. and its predecessor since 1983. He was also the founder of Yuma Co. He has 39 years of experience in the oil and natural gas industry, the majority of which he has been leading Yuma Co. Prior to founding Yuma Co., he held the position of Assistant to the President of Tomlinson Interests, a private independent oil and gas company. Mr. Banks graduated with a Bachelor of Arts from Tulane University in New Orleans, Louisiana, in 1972, and in 1976 he served as Republican Assistant Finance Chairman for the re-election of President Gerald Ford, under former Secretary of State, Robert Mosbacher.

James J. Jacobs has been our Chief Financial Officer, Treasurer and Corporate Secretary since December 2015. He served as our Vice President – Corporate and Business Development immediately prior to his appointment as Chief Financial Officer in December 2015 and has been with us since 2013. He has 15 years of experience in the financial services and energy sector. In 2001, Mr. Jacobs worked as an Energy Analyst at Duke Capital Partners. In 2003, Mr. Jacobs worked as a Vice President of Energy Investment Banking at Sanders Morris Harris where he participated in capital markets financing, mergers and acquisitions, corporate restructuring and private equity transactions for various sized energy companies. From 2006 through 2013, Mr. Jacobs was the Chief Financial Officer, Treasurer and Secretary at Houston America Energy Corp., where he was responsible for financial accounting and reporting for U.S. and Colombian operations, as well as capital raising activities. Mr. Jacobs graduated with a Master’s Degree in Professional Accounting and a Bachelor of Business Administration from the University of Texas in 2001.

Paul D. McKinney has been our Executive Vice President and Chief Operating Officer since October 2014. Mr. McKinney served as a petroleum engineering consultant for our predecessor from June 2014 to September 2014 and for us from September 2014 to October 2014. Mr. McKinney served as Region Vice President, Gulf Coast Onshore, for Apache Corporation from 2010 through 2013, where he was responsible for the development and all operational aspects of the Gulf Coast region for Apache. Prior to his role as Region Vice President, Mr. McKinney was Manager, Corporate Reservoir Engineering, for Apache from 2007 through 2010. From 2006 through 2007, Mr. McKinney was Vice President and Director, Acquisitions & Divestitures for Tristone Capital, Inc. Mr. McKinney commenced his career with Anadarko Petroleum Corporation and held various positions with Anadarko over a 23 year period from 1983 to 2006, including his last title as Vice President of Reservoir Engineering, Anadarko Canada Corporation. Mr. McKinney has a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University.

Available Information

Our principal executive offices are located at 1177 West Loop South, Suite 1825, Houston, Texas 77027. Our telephone number is (713) 768-7000. You can find more information about us at our website located at www.yumaenergyinc.com. Our Annual Report on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and any amendments to those reports are available free of charge on or through our website, which is not part of this report. These reports are available as soon as reasonably practicable after we electronically file these materials with, or furnish them to, the SEC. Information filed with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

Item 1A. Risk Factors.

We are subject to numerous 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.

Due to low current commodity prices, we anticipate that we may be required to take write-downs of the carrying values of our properties in 2016.

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. Based upon commodity prices as of March 31, 2016, we do not expect that we will incur an impairment charge in the first quarter of 2016, but we may incur impairments in future periods.

Our short-term liquidity is significantly constrained, and could severely impact our cash flow and our development of our properties.

Currently, our principal sources of liquidity are cash flow from our operations and borrowing under our credit facility. During the year ended December 31, 2015, we borrowed $6.9 million under our credit facility to fund a portion of our capital expenditures. On December 30, 2015, we entered into the Waiver, Borrowing Base Redetermination and Ninth Amendment to our credit agreement (the "Amendment"), which reduced our borrowing base to $29.8 million and automatically reduces our borrowing base to $20.0 million on May 31, 2016. As of March 29, 2016, our total borrowing base was $29.8 million with no remaining availability. This reduction severely limits our liquidity and limits our expenditures to our current cash flow. Furthermore, the Amendment automatically reduces our borrowing base by $9.8 million to $20.0 million on May 31, 2016. Accordingly, we will be in default under our credit agreement if we do not repay $9.8 million by May 31, 2016 or obtain an extension from our lenders. As a condition to the merger with Davis, we will need to enter into an amendment to our credit agreement to take into account the properties of Davis, which we anticipate will help our liquidity; however, we do not anticipate closing our merger with Davis until the middle of 2016 and will need to obtain a waiver from our lenders, which they may not provide. Additionally, the merger with Davis is subject to approval by our shareholders, including at least two-thirds of the shares of our Series A Preferred Stock. At this time, we have little capital to develop our properties.

Our audited financial statements for the year ended December 31, 2015 contain a going-concern qualification, raising questions as to our continued existence.

Our independent auditors have issued a going concern opinion, which means that there is substantial doubt about our ability to continue as a going concern. As of the date of this report, we will require additional funds for the balance of fiscal year 2016 to repay $9.8 million under our credit agreement when our borrowing base is reduced to $20.0 million on May 31, 2016 and to continue our operations. If we cannot raise these funds or complete the merger with Davis, we may be required to significantly alter our business plan, reduce our activities, sell assets, or we could be forced into bankruptcy or liquidation. These financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts, or amounts and classification of liabilities that might result from the possible inability to continue as a going concern.

Our credit facility has substantial restrictions and financial covenants and our ability to comply with those restrictions and covenants is uncertain. Our lenders can unilaterally reduce our borrowing availability based on anticipated commodity prices.

The terms of our credit agreement require us to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the credit facility or other debt agreements could result in a default under those agreements, which could cause all of our existing indebtedness to be immediately due and payable.

The credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the properties securing their loan. For example, our lenders have reduced our borrowing base from $29.8 million to $20.0 effective May 31, 2016. Significant recent decreases in the price of crude oil are likely to have an adverse effect on our borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other crude oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the credit facility. We anticipate that our merger with Davis will add substantial properties that may be pledged under our credit agreement; however, if the Davis merger is not approved by our shareholders, including at least two-thirds of the shares of our Series A Preferred Stock, we will not be able to complete the merger with Davis. Our inability to borrow additional funds under our credit facility could adversely affect our operations and our financial results, and possibly force us into bankruptcy or liquidation.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there would be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would impact our ability to make principal and interest payments on our indebtedness and satisfy our other obligations.

Any default under the agreements governing our indebtedness, including a default under our credit facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal and interest on our indebtedness and satisfy our other obligations. If we are unable to generate sufficient cash flows and are otherwise unable to obtain the funds necessary to meet required payments of principal and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. If our operating performance declines, we may in the future need to seek to obtain waivers from the required lenders under our credit facility to avoid being in default and we may not be able to obtain such a waiver. If this occurs, we would be in default under our credit facility, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. We cannot assure you that we will be granted waivers or amendments to our debt agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness and for other purposes would decrease.

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

Prices for oil, natural gas, and natural gas liquids can fluctuate widely. For example, the NYMEX West Texas Intermediate oil prices have been volatile and ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per barrel in February 2016. Also, NYMEX Henry Hub natural gas prices have been volatile and ranged from a high of $6.15 per million British thermal units (MMBtu) in February 2014 to a low of $1.64 per MMBtu in December 2015. Our revenues, profitability and our 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 is 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, and demand for, oil and natural gas;
- volatility and trading patterns in the commodity-futures markets;
- the ability of members of OPEC 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 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.

The long-term effect of these and other factors on the prices of oil and natural gas is uncertain. Prolonged or further declines in these commodity prices may have the following effects on our business:

- adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations;
- reducing the amount of oil and, natural gas that we can produce economically;
- causing us to delay or postpone a significant portion of our capital projects;
- materially reducing our revenues, operating income, or cash flows;
- reducing the amounts of our estimated proved oil and natural gas reserves;

reducing the carrying value of our oil and natural gas properties due to recognizing additional impairments of proved properties, unproved properties and exploration assets;

reducing the standardized measure of discounted future net cash flows relating to oil and natural gas reserves; and

limiting our access to, or increasing the cost of, sources of capital such as equity and long-term debt.

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 natural gas development project. At December 31, 2015, we held approximately 61,986 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 and non-proved undeveloped reserves and additional potential. Our independent petroleum engineering reserve report as of December 31, 2015 includes 22 operated proved undeveloped well locations and three non-operated proved undeveloped well locations, 63 operated non-proved undeveloped locations, and 11 non-operated non-proved undeveloped locations that are held by production or contain existing leasehold.

In December of 2014, we completed our second operated Austin Chalk well, the Crosby 14-1. While this well 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 that eventually led to problems producing the well. Due to restrictions in the horizontal section of the well bore, including down-hole drilling motor components, we were not able to run a slotted liner which is used to prevent, among other things, formation and drilling debris from entering the wellbore during production operations. Subsequent attempts to maintain sustained and economic production from the well failed because formation and drilling debris continued to plug the well. The well last produced in April 2015 and was subsequently shut-in.

As of December 31, 2015, the field contained approximately 84.1% of our total proved undeveloped reserves and 83.7% of the PV-10 of such reserves. Additionally, the field's proved undeveloped reserves represent approximately 61.7% 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 are currently seeking joint venture partners to participate in the future drilling and development of these locations, which would reduce our participating interest in these locations and thereby reduce our future capital expenditures and associated proved and non-proved reserves and production. We plan to drill one proved undeveloped well this year and the remaining proved undeveloped wells within five years from the date they were originally recorded. 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, 2016 assumes that the net capital for development of the field will be approximately $105 million over four years. 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, our ability to bring in other partners, 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, or attract joint venture partners would 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 prices may also make drilling certain 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.

A significant portion of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

A significant portion of our net leasehold acreage is undeveloped, or 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. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income, are dependent on successfully developing our undeveloped leasehold acreage.

Our undeveloped acreage must be drilled before lease expirations to hold the acreage by production. Failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our undeveloped leases and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. Approximately 79% of our total Masters Creek undeveloped acreage will be subject to expiration in 2016, with 20% of such acreage expiring in 2017, and 1% in 2018. As of December 31, 2015, leases representing 76%, 23%, and 1%, respectively, of our total undeveloped acreage are scheduled to expire in 2016, 2017, and 2018. The cost to renew expiring leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. If we are unable to fund renewals of expiring leases, we could lose portions of our acreage and our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

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, mechanical breakdowns, 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.

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, results of operations, and potentially the borrowing capacity under our credit facility.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the net present 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 net present value of our reserves. For instance, the SEC mandated prices used in estimating our proved reserves are $50.28 per Bbl of oil and $2.59 per MMBtu of natural gas, which are significantly higher than current spot market prices. 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, 2015, approximately 73.3% of our estimated reserves 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, 2015, 2014 and 2013, 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.

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 our 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 our company 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.

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 and economic 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 that 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 breakdowns, or accidents and shortages or delays in the availability of drilling and completion equipment and services;

fires, explosions, blowouts and surface cratering;

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 applicable laws may result in the suspension or termination of operations and subject us to liabilities, including administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, the laws governing our operations 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 environmental, health and safety laws and regulations, we also 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. Such laws 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 2015, the EPA issued a draft final report for public comment and peer review. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. For example, a BLM rulemaking for hydraulic fracturing practices on federal and Indian lands resulted in a 2015 final rule that requires 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.

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, the Kyoto Protocol and the Paris Agreement 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 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 issued a proposed rule in 2015 that would set additional standards for methane and emissions from oil and gas production sources, including hydraulically fractured oil wells and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. In addition, the BLM has proposed 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 to obtain emission allowances or to pay emission taxes, 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. 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 (the “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.

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 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. Also, it is possible that under recently adopted margin rules, some CFTC registered swap dealers may require us to post initial and variation margins in connection with certain swaps not subject to central clearing.

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, and reduce our ability to monetize or restructure our existing commodity derivative contracts. 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.

Certain federal income tax deductions currently available with respect to crude oil and natural gas and exploration and development may be eliminated as a result of future legislation.

The Obama administration has proposed to eliminate certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The proposals include, but are not limited to (i) the repeal of the percentage depletion deduction for crude oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. In addition, President Obama has recently proposed a $10.25 per barrel tax on oil companies. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could result in higher federal income taxes, which could negatively affect our financial condition and results of operations. In addition, proposals are made from time to time in states where we operate to implement or increase severance or other taxes at the state level, and any such additional taxes would have similarly adverse effects on us.

We participate in oil and natural gas leases with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil and natural gas prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

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.

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 commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity 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.

A component of our growth may come through acquisitions, and our failure to identify or complete future acquisitions successfully could reduce our earnings and slow our growth.

We may be unable to identify properties for acquisition or to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The completion and pursuit of acquisitions may be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to grow through acquisitions will require us to continue to invest in operations and financial and management information systems and to attract, retain, motivate and effectively manage our employees.

In addition, we may be unable to successfully integrate any potential acquisitions into our existing operations. The inability to manage the integration of acquisitions, including our merger with Davis, effectively could reduce our focus on subsequent acquisitions and current operations, and could negatively impact our results of operations and growth potential. Members of our management team may be required to devote considerable amounts of time to the integration process, including with respect to the merger of Davis, which will decrease the time they will have to manage our business.

Furthermore, our decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which our staff is familiar may impact our productivity in such areas. Our financial condition, results of operations and cash flows may fluctuate significantly from period to period as a result of the completion of significant acquisitions during particular periods.

We may engage in bidding and negotiation to complete successful acquisitions. We may be required to alter or increase substantially our capitalization to finance these acquisitions through the use of cash on hand, the issuance of debt or equity securities, the sale of production payments, the sale of non-strategic assets, the borrowing of funds or otherwise. Our credit agreement includes covenants limiting our ability to incur additional debt. If we were to proceed with one or more acquisitions involving the issuance of our common stock, our shareholders would suffer dilution of their interests.

We may be unsuccessful in combining Davis' business with our existing business.

The success of the proposed merger of Davis will depend, in part, on our ability to realize the anticipated benefits and synergies from combining our business and existing asset base with the business of Davis and the assets obtained in the merger of Davis. To realize these anticipated benefits, the businesses must be successfully integrated. If we are not able to achieve these objectives, or we are not able to achieve these objectives on a timely basis, the anticipated benefits of the merger of Davis may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the merger of Davis. These integration difficulties could have a material adverse effect on our business, financial condition and results of operations.

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.

The low trading volume of our common stock may adversely affect the price of our shares and their liquidity.

Although our common stock is listed on the NYSE MKT exchange, our common stock has experienced low trading volume. Limited trading volume may subject our common stock to greater price volatility and may make it difficult for investors to sell shares at a price that is attractive to them.

If our common stock price declines, our common stock may be subject to delisting from the NYSE MKT.

Our common stock is currently trading at a price of less than $1.00 per share. We currently meet the continued listing standards of NYSE MKT. However, we cannot assure you that we will be able to continue to comply with the minimum bid price and the other standards that we are required to meet in order to maintain a listing of our common stock on the NYSE MKT. Our failure to continue to meet these requirements may result in our common stock being delisted from the NYSE MKT. If our common stock is delisted, this would, among other things, substantially impair our ability to raise additional funds and could result in a loss of institutional investor interest and fewer development opportunities for us.

If our common stock were delisted and determined to be a "penny stock," a broker-dealer may find it more difficult to trade our common stock, and an investor may find it more difficult to acquire or dispose of our common stock in the secondary market.

If our common stock were removed from listing with the NYSE MKT, it may be subject to the so-called "penny stock" rules. The SEC has adopted regulations that define a penny stock to be any equity security that has a market price per share of less than $5.00, subject to certain exceptions, such as any securities listed on a national securities exchange. For any transaction involving a penny stock, unless exempt, the rules impose additional sales practice requirements on broker-dealers, subject to certain exceptions. If our common stock were delisted and determined to be a penny stock, a broker-dealer may find it more difficult to trade our common stock, and an investor may find it more difficult to acquire or dispose of our common stock on the secondary market.

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 29, 2016, 554,596 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, 2016, we had $29.8 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. Beginning with dividends accruing as of November 1, 2015, our board of directors suspended payment of dividends on the Series A Preferred Stock until such time as the Company has sufficient liquidity to restore payment of such dividends.

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.

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 in the future 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 and pay accrued and unpaid dividends in the future, or to pay our indebtedness or to fund our other liquidity needs.

We do not expect to pay any cash dividends on our Series A Preferred Stock for the foreseeable future.

Our board of directors suspended the monthly cash dividend payment on the Series A Preferred Stock as a result of the depressed commodity price environment which has adversely affected our cash flows and liquidity. Accordingly, we do not anticipate that we will pay any cash dividends on shares of our Series A Preferred Stock for the foreseeable future. Any determination to pay dividends in the future will be at the discretion of our board of directors and will depend upon commodity prices, results of operations, financial condition, contractual restrictions, restrictions imposed by applicable law and other factors our board of directors deems relevant. In addition, we are currently limited in our ability to declare dividends or make distributions on account of our Series A Preferred Stock under the terms of our credit agreement. Additionally, if dividends on our Series A Preferred Stock are in arrears and unpaid for six or more quarterly periods, the holders (voting as a single class) of our outstanding Series A Preferred Stock will be entitled to elect two additional directors to our board of directors until paid in full.

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.

Notwithstanding the above, pursuant to the merger agreement with Davis, we have agreed as part of the reincorporation from California to Delaware, subject to approval of the holders of Series A Preferred Stock, to convert each share of our existing Series A Preferred Stock into 35 shares of common stock prior to giving effect for the reverse split (3.5 shares post reverse split).

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:

- our suspension of the cash payment of dividends on the Series A Preferred Stock;
- 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 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 17 – 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		
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
2015		
March 31	$2.11	$1.01
June 30	$1.17	$0.49
September 30	$0.83	$0.30
December 31	$0.60	$0.13

As of March 22, 2016, there were approximately 205 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 report contain additional information that should be referred to when reviewing this material.

The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, joint ventures and dispositions, uncertainties in estimating proved reserves and forecasting production results, potential failure to achieve production from development projects, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital and financial markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements" and Item 1A. "Risk Factors."

Overview

We are a Houston-based oil and gas company focused on the acquisition, development, and exploration for conventional and unconventional oil and natural gas resources in the U.S. Gulf Coast and California. 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 and southern 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.

Recent developments

The prices of crude oil and natural gas have declined dramatically since mid-year 2014, having recently reached multiyear lows, as a result of robust supply growth, weakening demand in emerging markets, and OPEC's decision to continue to produce at current levels. These market dynamics have led many to conclude that commodity prices are likely to remain lower for a prolonged period. In response to these developments, among other things, we have reduced our spending and looked to enter into a merger with Davis Petroleum Acquisition Corp. to increase our liquidity and improve our financial position (see description of the merger in Part II, Item 8. Notes to the Consolidated Financial Statements, Note 24 – Subsequent Events). In addition, we are continuing to actively explore and evaluate various strategic alternatives, including asset sales, to reduce the level of our debt and lower our future cash interest obligations. We believe that a reduction in our debt and cash interest obligations on a per barrel basis is needed to improve our financial position and flexibility and to position us to take advantage of opportunities that may arise out of the current industry downturn.

Reserves and non-cash full cost ceiling impairment

Our results of operations are heavily influenced by oil and natural gas prices, which have significantly declined and have remained low during the last year. These oil and natural gas price fluctuations are caused by changes in the global and regional supply of and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of and our ability to fund drilling projects, as well as the economic valuation and economic recovery of oil and natural gas reserves.

As discussed previously in this report, during 2015 commodity prices for crude oil and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD," and have adjusted our drilling schedule and PUD bookings due to the current economic price environment and our financial condition. We have focused on our efforts to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable. Although we believe that we have a plan to develop our reserves, the current environment and the industry's access to the capital markets may affect our ability to execute this plan.

NSAI, our independent reserve engineers, estimated 100% of our proved reserves as of December 31, 2015 and 2014. As of December 31, 2015, we had 13,261 MBoe of estimated proved reserves as compared to 19,888 MBoe of estimated proved reserves as of December 31, 2014. For prices used to value our reserves, See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 25 – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited).

Potential future low commodity price impact on our development plans, reserves and full cost impairment

Oil and natural gas prices have remained low in the first quarter of 2016. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we may incur a non-cash full cost impairment during 2016, which will have an adverse effect on our results of operations.

There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods. In addition to unknown future commodity prices, other uncertainties include (i) changes in drilling and completion costs, (ii) changes in oilfield service costs, (iii) production results, (iv) our ability, in a low price environment, to strategically drill the most economic locations in our targets, (v) income tax impacts, (vi) potential recognition of additional proved undeveloped reserves, (vii) any potential value added to our proved reserves when testing recoverability from drilling unbooked locations and (viii) the inherent significant volatility in the commodity prices for oil and natural gas recently exemplified by the large changes in recent months.

Each of the above factors is evaluated on a quarterly basis and if there is a material change in any factor it is incorporated into our internal reserve estimation utilized in our quarterly accounting estimates. We use our internal reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our reserve development plans for our reported reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our reserve development plans.

We have set forth below a calculation of a potential future reduction of our proved reserves. Such implied impairment and decrease in reserves should not be interpreted to be indicative of our development plan or of our actual future results. Each of the uncertainties noted above has been evaluated for material known trends to be potentially included in the estimation of possible first-quarter effects. Based on such review, we determined that the impact of decreased commodity prices, changes to our reserves and future production due to expiring leases, and the roll-off of our estimated production are the only significant known variables in the following scenario.

Both our hypothetical first-quarter 2016 full cost ceiling calculation and our hypothetical reserves estimates have been prepared by substituting (i) $46.26 per barrel for oil, and (ii) $2.40 per MMBtu for natural gas (the "Pro Forma Prices") for the respective realized prices as of March 31, 2016. Changes to our reserves and future production due to expiring leases were made as well as changing the effective date of the evaluation from December 31, 2015 to March 31, 2016 to account for the roll-off of the estimated production and reduction in reserves. All other inputs and assumptions have been held constant. Accordingly, this estimation accounts for the impact of more current commodity prices on the first-quarter 2016 realized prices that will be utilized in our full cost ceiling calculation and our reserves estimate. The Pro Forma Prices use a slightly modified realized price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for oil, natural gas liquids and natural gas on the first day of the month for the 12 months ended March 1, 2016. Using this methodology, the estimated implied impact to our December 31, 2015 reserves of 13,261 MBoe would be a reduction of 3,478 MBoe. However, this estimated reduction would not result in a first quarter ceiling test impairment in 2016. We believe that substituting the Pro Forma Prices into our December 31, 2015 internal reserve estimates may help provide users with an understanding of the potential first-quarter price impact on our March 31, 2016 full cost ceiling test and in preparing our year-end reserve estimates.

Mergers and acquisitions

On February 10, 2016, the Company and privately held Davis Petroleum Acquisition Corp. ("Davis") entered into a definitive merger agreement for an all-stock transaction. Upon completion of the transaction, we will reincorporate in Delaware, implement a one-for-ten reverse split of our common stock, and convert each share of our existing Series A Preferred Stock into 35 shares of common stock prior to giving effect for the reverse split (3.5 shares post reverse split). Following these actions, we will issue additional shares of common stock in an amount sufficient to result in approximately 61.1% of the common stock being owned by the current common stockholders of Davis. In addition, we will issue approximately 3.3 million shares of a new Series D preferred stock to existing Davis preferred stockholders, which is estimated to have a conversion price of approximately $5.70 per share, after giving effect for the reverse split. The Series D preferred stock is estimated to have an aggregate liquidation preference of approximately $18.7 million at closing, and will be paid dividends in the form of additional shares of Series D preferred stock at a rate of 7% per annum. Upon closing, there will be an aggregate of approximately 23.7 million shares of our common stock outstanding (after giving effect to the reverse stock split and conversion of Series A Preferred Stock to common stock). The transaction is expected to qualify as a tax-deferred reorganization under Section 368(a) of the Code.

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, 2015, 2014 and 2013, and the average sales price per unit sold.

	Years Ended December 31,		
	2015	2014	2013
Production volumes:			
Crude oil and condensate (Bbl)	247,177	231,816	184,349
Natural gas (Mcf)	1,993,842	2,714,586	1,580,468
Natural gas liquids (Bbl)	74,511	97,783	51,875
Total (Boe) (1)	653,995	782,030	499,635
Average prices realized:			
Excluding commodity derivatives:			
Crude oil and condensate (per Bbl)	$48.07	$93.98	$104.26
Natural gas (per Mcf)	$2.60	$4.62	$3.83
Natural gas liquids (per Bbl)	$18.89	$38.44	$40.17
Including commodity derivatives:			
Crude oil and condensate (per Bbl)	$65.20	$101.98	$104.39
Natural gas (per Mcf)	$3.00	$5.19	$3.71
Natural gas liquids (per Bbl)	$18.89	$38.44	$40.17

(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, 2015, 2014 and 2013.

	Years Ended December 31,		
	2015	2014	2013
Sales of natural gas and crude oil:			
Crude oil and condensate	$11,881,626	$21,785,636	$19,220,185
Natural gas	5,181,715	12,542,671	6,049,500
Natural gas liquids	1,407,512	3,758,875	2,083,905
Gain/(loss) on commodity derivatives	5,038,826	3,398,518	(159,810)
Gas marketing	209,731	572,210	881,823
Total revenues	$23,719,410	$42,057,910	$28,075,603

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, Basic Sediment and Water (“BS&W”) and transportation. Generally, the index or posting is based on West Texas Intermediate (“WTI”) and adjusted to Light Louisiana Sweet (“LLS”) or Heavy Louisiana Sweet (“HLS”). For the years ended December 31, 2015, 2014 and 2013, LLS postings averaged $3.48, $3.02 and $9.58 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 were 6.6% higher for the year ended December 31, 2015 than the crude oil volumes sold during the year ended December 31, 2014. This increase was a result of increased production from Livingston and Main Pass 4 wells and a full year of production from our California assets, partially offset by declines from Masters Creek and La Posada properties. In the Livingston area fields, we focused on optimizing the artificial lift systems and reducing downtime and workovers. At Main Pass 4, we re-engineered the facilities to increase our water handling and disposal capacity and to improve run-times. Realized crude oil prices experienced a 48.9% decrease from the year ended December 31, 2014 to the year ended December 31, 2015.

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 came from two wells and the newly acquired Pyramid wells, and was further enhanced by increased sales on five wells after successful workover operations. Some reductions were due to the shut-in of two wells for salt water disposal well work and declining production from two other wells and the Bakken wells in North Dakota. Realized crude oil prices experienced a 9.9% decrease from the year ended December 31, 2013 to the year ended December 31, 2014.

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, 2015 compared to the year ended December 31, 2014, we experienced a 26.6% decrease in natural gas volumes sold and a 23.8% decrease in natural gas liquids sold primarily due to production declines in the Bayou Hebert (La Posada) field, which were partially offset by new production from our Talbot 23-1 well. During the same period, realized natural gas prices decreased by 43.7% and realized natural gas liquids prices decreased by 50.9%.

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 from the Crosby 12-1 and the net revenue increase at La Posada, partially offset by production declines from the Broussard No. 2 and Thibodeaux No. 1. These increases in natural gas sales led to increases in natural gas liquids sales of 88.5%. During the same period, realized natural gas prices increased by 20.6% and realized natural gas liquids prices decreased by 4.3%.

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 on behalf of our working interest partners. In early 2016, we discontinued Marketing due to a lack of volumes and the associated costs of running the company (see Part II, Item 8. Notes to the Consolidated Financial Statements, Note 24 – Subsequent Events).

Expenses

Lease Operating Expenses

Our lease operating expenses ("LOE") and LOE per Boe for the years ended December 31, 2015, 2014 and 2013, are set forth below:

	Years Ended December 31,		
	2015	2014	2013
Lease operating expenses	$7,531,846	$7,350,237	$5,265,794
Severance, ad valorem taxes and marketing	3,869,463	5,466,488	4,050,570
Total LOE	$11,401,309	$12,816,725	$9,316,364
LOE per Boe	$17.43	$16.39	$18.65
LOE per Boe without severance, ad valorem taxes and marketing	$11.52	$9.40	$10.54

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.

The 11.0% decrease in total LOE for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to operating cost reduction initiatives implemented in our Greater Masters Creek Area, Livingston, and California. LOE per barrel of oil equivalent increased by 6.3% for the same period generally due to the lower natural gas and natural gas liquids sales when compared to the prior year.

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, 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 acquired. LOE per barrel of oil equivalent decreased by 12.1% for the same period generally due to increased sales volumes.

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, 2015, 2014 and 2013 totaled $555,539, $3,084,972, and $2,521,707, respectively. Workover expenses decreased by 82.0% in the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily because of the high workover expenses incurred in 2014 to restore salt water disposal at Gardner Island (Main Pass 4) and Raccoon Island (Main Pass 2). Additionally, in 2015 the artificial lift optimization projects completed in Livingston, the re-engineered facilities installed at Main Pass 4, and the cost reduction initiatives at Masters Creek and in California led to fewer workovers, down time, and less activity overall. Workover expenses increased by 22.3% 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. Additionally, LOE per Boe, including re-engineering and workovers, for the years ended December 31, 2015, 2014 and 2013 totaled $18.28, $20.33 and $23.69, respectively. All re-engineering work performed in 2015 was completed prior to July 2015. Additional work planned for 2015 was deferred due to commodity prices.

General and Administrative Expenses

Our general and administrative ("G&A") expenses for the years ended December 31, 2015, 2014 and 2013, are summarized as follows:

	Years Ended December 31,		
	2015	2014	2013
General and administrative:			
Stock-based compensation	$3,086,209	$4,293,855	$589,164
Capitalized	(796,898)	(905,534)	(137,106)
Net stock-based compensation	2,289,311	3,388,321	452,058
Other	9,727,419	10,692,639	7,186,069
Capitalized	(2,293,115)	(2,536,562)	(2,649,563)
Net other	7,434,304	8,156,077	4,536,506
Net general and administrative expenses	$9,723,615	$11,544,398	$4,988,564

G&A expenses primarily consist of overhead expenses, employee remuneration and professional and consulting fees. We capitalize certain G&A expenditures when 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, 2015, net G&A expenses were $1,820,783 (15.8%) less than the amount for the prior year ended December 31, 2014. The reduction in G&A expenses was primarily attributed to a decrease in stock-based compensation, along with higher costs in 2014 for professional fees associated with the merger and costs to explore other public listing options. Stock-based compensation net of amounts capitalized totaled $2,289,311 and $3,388,321 for fiscal years 2015 and 2014, respectively. Non-recurring professional costs related to the merger and costs to explore other public listing options totaled $113,997 and $2,935,536 in fiscal years 2015 and 2014, respectively. Also included in 2015 G&A costs were $406,556 in non-recurring severance benefits for several employees terminated at year-end.

For the year ended December 31, 2014, net G&A expenses were $6,555,834 (131.4%) over the amount for the prior year ended December 31, 2013. The increases were due in large part to the initial amortization of restricted stock awards at the time of the merger, triggered as a result of the condition of the Company going public. 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 $581,093, or 12.9%, over 2013. This increase was primarily the result of five (net) employee additions in 2014.

Depreciation, Depletion and Amortization

Our depreciation, depletion and amortization ("DD&A") for the years ended December 31, 2015, 2014 and 2013, is summarized as follows:

	Years Ended December 31,		
	2015	2014	2013
DD&A	$13,651,207	$19,664,991	$12,077,368

DD&A per Boe	$20.87	$25.15	$24.17

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DD&A per Boe decreased by 17.0% for the year ended December 31, 2015 compared to the year ended December 31, 2014. The decrease resulted primarily from the reduction of the net quantities of natural gas and natural gas liquids sold by us and the reduction of the proved reserves associated with the reclassification of proved undeveloped reserves to non-proved. The net quantities of oil, natural gas and natural gas liquids produced and sold by us increased by 56.5% for the year ended December 31, 2014 compared to the year ended December 31, 2013. This increase in production was the primary factor for the 4.1% increase in DD&A per Boe in 2014 over 2013. See “Production” above for the volumes of oil, natural gas and natural gas liquids production.

NON-GAAP FINANCIAL MEASURES

Adjusted EBITDA

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

	Years Ended December 31,		
	2015	2014	2013
Net Income (loss)	$(11,005,038)	$(20,225,150)	$(33,050,103)
Depreciation, depletion & amortization of property and equipment	13,651,207	19,664,991	12,077,368
Interest expense, net of interest income and amounts capitalized	436,836	302,568	560,340
Income tax benefit	(7,983,039)	(2,553,854)	3,080,272
Goodwill impairment	5,349,988	-	-
Stock-based compensation net of capitalized cost	2,289,311	3,388,321	452,058
Unrealized (gains) losses on commodity derivatives	949,967	(4,724,985)	231,886
Accretion of asset retirement obligation	604,538	604,511	668,497
Costs to obtain a public listing	-	2,935,536	24,592
Increase in value of preferred stock derivative liability	-	15,676,842	26,258,559
Bank mandated commodity derivative novation cost	-	-	175,000
Amortization of benefit from commodity derivatives sold	-	(93,750)	(72,600)
Adjusted EBITDA	$4,293,770	$14,975,030	$10,405,869

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also used to assess our ability to incur and service debt and fund capital expenditures.

Our Adjusted EBITDA should not be considered an alternative to net income (loss), operating income (loss), cash flow provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. Adjusted EBITDA for the year ended December 31, 2015 decreased from 2014 by $10,681,260 (71.3%). Adjusted EBITDA for the year ended December 31, 2014 increased from 2013 by $4,569,161 (43.9%).

Interest Expense

Our interest expense for the years ended December 31, 2015, 2014 and 2013, is summarized as follows:

	Years Ended December 31,		
	2015	2014	2013
Interest expense	$1,439,895	$1,385,550	$1,599,492

Interest capitalized	(983,472)	(1,059,350)	(1,031,816)
Net	$456,423	$326,200	$567,676
Bank debt	$29,800,000	$22,900,000	$31,215,000

Interest expense increased $54,345 for the year ended December 31, 2015 over the same period in 2014 as a result of increased borrowings during 2015. Capitalized interest decreased $75,878 for the year ended December 31, 2015 from the same period in 2014, driven by a decrease in our unevaluated properties since 2014, which is the basis of our capitalized interest calculation.

Interest expense decreased $213,942 for the year ended December 31, 2014 from the same period in 2013 as a result of debt decreasing 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. Capitalized interest increased $27,534 for the year ended December 31, 2014 over the same period in 2013 due to an increase in the value of oil and gas properties not subject to amortization.

For a more complete narrative of interest expense, refer to Note 13 – Debt and Interest Expense 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, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
Consolidated net income (loss) before income taxes	$(18,988,077)	$(22,779,004)	$(29,969,831)
Income tax expense (benefit)	(7,983,039)	(2,553,854)	3,080,272
Effective tax rate	42.04%	11.21%	(10.28)%

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 benefit has been recognized for nondeductible expenses. Refer to Note 16 – Income Taxes in the Notes to Consolidated Financial Statements included in this report.

Liquidity and Capital Resources

Our primary and potential sources of liquidity include cash on hand, cash from operating activities, borrowings under our revolving credit facility, proceeds from the sales of assets, and potential proceeds from capital market transactions, including the sale of debt and equity securities. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices, as well as variations in our production. Our business plan contemplates the potential merger with Davis Petroleum Acquisitions Corp., which we anticipate will help us with our liquidity and potentially put us in compliance with our credit facility. While we anticipate the completion of this merger, we are subject to a number of factors that are beyond our control, including commodity prices, our bank's determination of our borrowing base which could impact the merger, production declines, and other factors that could affect our liquidity and ability to continue as a going concern. Our 2016 business plan includes the capital to drill two wells, a Greater Masters Creek Field Area proved undeveloped location and another proved undeveloped location in Santa Barbara County, California in the Cat Canyon field once the necessary permits are approved. Other capital investments are also planned for both operated and non-operated recompletions, artificial lift upgrades, and capitalized workovers.

Cash Flows

Our net increase (decrease) in cash for the years ended December, 31, 2015, 2014 and 2013, is summarized as follows:

	Years Ended December 31,		
	2015	2014	2013
Cash flows provided by (used in) operating activities	$(1,370,144)	$24,466,300	$14,912,903

Cash flows used in investing activities	(12,311,157)	(18,088,363)	(27,253,041)
Cash flows provided by (used in) financing activities	7,478,170	985,874	11,249,627
Net increase (decrease) in cash	$(6,203,131)	$7,363,811	$(1,090,511)

Cash Flows From Operating Activities

Cash flows from operations for the year ended December 31, 2015 decreased by $25,836,444, or 106%, over fiscal year 2014 primarily due to changes in working capital, decreased revenues due to low commodity prices, and decreased production.

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 Investing Activities

During the year ended December 31, 2015, we had a total of $10,126,307 in oil and natural gas investing activities. Of that, $4,366,695 was related to acquisitions of acreage and new properties, which included capitalized G&A and interest costs of $3.2 million, and approximately $0.77 million of acquisition costs for additional interest in our Livingston and Branville Bay assets. Drilling and completion activity during the period totaled $4,219,210. The majority of drilling and completion activity in 2015 is attributed to the drilling and completion of the Talbot 23-1 well for $3,181,382, and the completion of the Blackwell 39-1 and the Crosby 14-1 wells for $386,403 and $361,347, respectively. Recompletions, workovers and P&A activity totaled $1,540,402. Notable projects include installing a gas lift system in a Masters Creek well for $485,134, installing electrical submersible pumps (ESP) in two Livingston Parish oil wells for $401,200, and re-engineering production and SWD facilities at Main Pass 4 for $176,825.

During the year ended December 31, 2014, the Greater Masters Creek Field Area 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 3-D 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 3-D 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.

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 future crude oil and natural gas production through 2017, a significant deterioration in commodity prices negatively impacts revenues, earnings, cash flows, capital spending, and 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, sale of non-strategic assets, and the possible 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 December 30, 2015, we entered into the Waiver, Borrowing Base Redetermination and Ninth Amendment to the credit agreement which provided for a $29.8 million conforming borrowing base, which will be automatically reduced to $20.0 million on May 31, 2016 unless otherwise reduced by or to a different number by the lenders under the credit agreement.

During the year ended December 31, 2015, we sold 46,857 shares of our Series A Preferred Stock for aggregate net proceeds of $870,386, after deducting underwriting discounts and offering expenses, and 1,347,458 shares of our common stock for aggregate gross proceeds of $1,363,160, after deducting underwriting discounts and offering expenses under our sales agreement. We used the net proceeds from the offering to fund our capital expenditures and to repay our debt.

At December 31, 2015, we had a $29.8 million conforming borrowing base with $29.8 million advanced, leaving no available borrowing capacity. The borrowing base will be reduced to $20.0 on May 31, 2016.

	Years Ended December 31,		
	2015	2014	2013
Credit facility:			
Balances outstanding, beginning of year	$22,900,000	$31,215,000	$17,875,000
Activity	6,900,000	(8,315,000)	13,340,000
Balances outstanding, end of period	$29,800,000	$22,900,000	$31,215,000

Other than the credit facility, we had debt of $263,635 and $282,843 at December 31, 2015 and December 31, 2014, respectively, from installment loans financing oil and natural gas property insurance premiums. We had a cash balance of $5,355,191 at December 31, 2015.

We were in breach of the financial covenant in our credit agreement related to the maximum permitted ratio of funded debt to EBITDA for the fiscal quarters ended September 30, 2015 and December 31, 2015 as well as our EBITDA to interest expense covenant at December 31, 2015. We received a waiver of these breaches pursuant to an amendment to our credit agreement. See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 3 – Liquidity Considerations.

Credit Facility

We have a credit facility with a syndicate of banks that, as of December 31, 2015, had a borrowing base of $29.8 million through May 31, 2016 and thereafter the borrowing base will automatically be reduced to $20.0 million unless otherwise reduced by or to a different amount by the lenders under the credit agreement, with borrowings of $29.8

million outstanding. The credit agreement governing our credit facility provides for interest-only payments until May 20, 2017, when the credit agreement matures and any outstanding borrowings are due. The borrowing base under our credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base.

Our obligations under the credit agreement are guaranteed by our subsidiaries and are secured by liens on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 85% of the proved developed reserve value and at least 50% of the proved undeveloped reserve value of the oil and natural gas properties included in the determination of the borrowing base.

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. See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 3 – Liquidity Considerations and Note 13 – Debt and Interest Expense.

We are subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of EBITDA to Interest Expense (which includes dividends as defined in the credit agreement) of not less than 2.75 to 1.0; (2) a ratio of Funded Debt to EBITDA (as defined in the credit agreement) of not more than 4.0 to 1.0; and (3) a ratio of current assets to current liabilities of not less than 1.0 to 1.0. As of September 30, 2015, we were not in compliance with the ratio of Funded Debt to EBITDA and received a waiver for compliance from our lenders. Further, the waiver also waived any failure to comply with the above financial covenants as of December 31, 2015, at which time both the funded debt to EBITDA and the EBITDA to interest expense ratios were not in compliance. Because the financial covenants are determined as of the last day of each quarter, the ratios can fluctuate significantly period to period as the amounts outstanding under the credit agreement are dependent on the timing of cash flows from operations, capital expenditures, acquisitions and dispositions of oil and natural gas properties and securities offerings.

Our credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, payment of cash dividends on our Series A Preferred Stock, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The credit agreement is subject to customary events of default, including in connection with a change in control. If an event of default occurs and is continuing, the lenders may elect to accelerate amounts due under the credit agreement (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

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, 2015		December 31, 2014	
	Oil	Natural Gas	Oil	Natural Gas
Assets				
Current	$2,393,032	$265,015	$1,851,542	$1,486,995
Noncurrent	1,049,661	20,880	1,006,845	396,264

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 9 – Commodity Derivative Instruments.

The fair market value of our commodity derivative contracts in place at December 31, 2015 and December 31, 2014 were net assets of $3,728,588 and $4,741,646, respectively. We sold all of our oil and natural gas options (while retaining swap contracts) in February 2015 for $4.03 million, accounting for the decrease in market value from December 31, 2014. New swaps and options contracts were concurrently initiated for the remainder of 2015 through 2017.

See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 9 – 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. 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 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, 2015:

	Debt (1)	Asset for Commodity Derivatives (2)	Operating Leases	Asset Retirement Obligations
2016	$30,063,635	$2,658,047	$579,873	$70,000
2017	-	1,070,541	564,326	546,284
2018	-	-	2,264	3,691,016
2019	-	-	-	2,273,289
2020	-	-	-	60,330
Thereafter	-	-	-	2,149,579
Totals	$30,063,635	$3,728,588	$1,146,463	$8,790,498

(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, 2015. 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 1 – 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 Consolidated Statement of Operations 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.

Derivatives Associated with Preferred Stock

We 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 we were 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. As a result of the application of the two-step process during the second quarter of 2015, the Company determined to write-off the entire goodwill associated with the Pyramid acquisition of $5.3 million.

Share-based Compensation

We have three types of long-term incentive awards – restricted stock awards (“RSAs”), restricted stock units (“RSUs”) and stock appreciation rights (“SARs”). We account for them differently. RSUs are treated as either a liability or as equity, depending on management’s intentions to pay them in either cash or stock at their vesting date. 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 either from the point in time when the Company became public (for RSAs which had a performance-based requirement in order to vest) or from the time of issuance. SARs are valued at the time of issuance and amortized over the estimated period they are expected to be outstanding.

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.

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

None.

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, as of December 31, 2015, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time.

Under the supervision of, and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control-Integrated Framework, (2013 Version) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2015.

Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the SEC that permit us to provide only management's report in this report. Therefore, this report does not include such an attestation.

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, 2015 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.

See list of “Executive Officers of the Company” under Item 1 of this report, which is incorporated herein by reference.

Board of Directors of the Company

The following table sets forth the names and ages of all current directors, the positions and offices with us held by such persons, the years in which their current terms as directors expire and the commencement of their continuous service as a director:

Name	Director Since	Age	Position	Expiration of Term
Sam L. Banks	Sept. 2014	66	Chairman of the Board, President and Chief Executive Officer	2017
James W. Christmas	Sept. 2014	68	Director	2016
Frank A. Lodzinski	Sept. 2014	66	Director	2016
Ben T. Morris	Sept. 2014	69	Director	2017
Richard K. Stoneburner	Sept. 2014	62	Director	2016

The following paragraphs contain certain information about each of our directors.

Sam L. Banks has been our Chief Executive Officer and Chairman of the Board of Directors since the closing of the merger on September 10, 2014 and also President since October 10, 2014. He was the Chief Executive Officer and Chairman of the board of directors of Yuma Co. and its predecessor since 1983. He was also the founder of Yuma Co. He has 38 years of experience in the oil and gas industry, the majority of which he has been leading Yuma Co. Prior to founding Yuma Co., he held the position of Assistant to the President of Tomlinson Interests, a private independent oil and gas company. Mr. Banks graduated with a Bachelor of Arts from Tulane University in New Orleans, Louisiana, in 1972, and in 1976 he served as Republican Assistant Finance Chairman for the re-election of President Gerald Ford, under former Secretary of State, Robert Mosbacher.

The board of directors, in reviewing and assessing the contributions of Mr. Banks to the board, determined that his leadership and intimate knowledge of the oil and gas industry, the Company’s structure, and its properties and operations, provide the board of directors with company-specific experience and expertise.

James W. Christmas has served as a director and member of our audit and compensation committees since the closing of the merger on September 10, 2014. He has served as a director of Yuma Co. since November 2013. Mr. Christmas began serving as a director of Petrohawk Energy Corporation (“Petrohawk”) on July 12, 2006, effective upon the merger of KCS Energy, Inc. (“KCS”) into Petrohawk. He continued to serve as a director, and as Vice Chairman of the Board of Directors, for Petrohawk until BHP Billiton acquired Petrohawk in August 2011. He also served on the audit committee and the nominating and corporate governance committee. Mr. Christmas served as a member of the Board of Directors of Petrohawk, a wholly-owned subsidiary of BHP Billiton, and as chair of the financial reporting committee of such board from August 2013 through September 2014. On January 29, 2014, Mr. Christmas was appointed to the Board of Directors of Rice Energy, Inc., and serves as chairman of its audit committee and as a member of its compensation committee. He also serves on the Advisory Board of the Tobin School of Business of St. John’s University. He served as President and Chief Executive Officer of KCS from 1988 until April 2003 and Chairman of the Board and Chief Executive Officer of KCS until its merger into Petrohawk. Mr. Christmas was a

Certified Public Accountant in New York and was with Arthur Andersen & Co. from 1970 until 1978 before leaving to join National Utilities & Industries ("NUI"), a diversified energy company, as Vice President and Controller. He remained with NUI until 1988, when NUI spun out its unregulated activities that ultimately became part of KCS. As an auditor and audit manager, controller and in his role as CEO of KCS, Mr. Christmas was directly or indirectly responsible for financial reporting and compliance with SEC regulations, and as such has extensive experience in reviewing and evaluating financial reports, as well as in evaluating executive and board performance and in recruiting directors. He has extensive experience in oil and gas company growth issues, with a focus on capital structure and business development strategies. Prior to his appointment as a Director, Mr. Christmas was a Board Advisor to Yuma Co. from August 2012 through November 2013. Mr. Christmas received a bachelor's degree in accounting and an honorary degree of commercial science from St. John's University.

The board of directors, in reviewing and assessing the contributions of Mr. Christmas to the board, determined that his prior experience as an executive and director and his past audit, accounting and financial reporting experience provide significant contributions to the board of directors.

Frank A. Lodzinski has served as a director and member of our audit committee since the closing of the merger on September 10, 2014. He has served as a director of Yuma Co. since August 2012. He has more than 43 years of oil and gas industry experience, including the successful completion of several reverse mergers. In 1984, Mr. Lodzinski formed Energy Resource Associates, Inc., which acquired management and controlling interests in oil and gas limited partnerships, joint ventures and producing properties. Certain partnerships were exchanged for common shares of Hampton Resources Corporation in 1992, which was ultimately sold to Bellwether Exploration in 1995. In 1996, Mr. Lodzinski acquired Cliffwood Oil and Gas and then a controlling interest in Texoil where he served as President, CEO, and a Director. Texoil was sold to Ocean Energy in 2001. From 2001 to 2004, Mr. Lodzinski served as President, CEO, and Director of AROC to direct the restructuring and ultimate liquidation of the company in 2004. In 2004, Mr. Lodzinski formed Southern Bay Energy and merged that company into GeoResources, Inc. He served as President, CEO, and a Director until GeoResources was sold to Halcón Resources Corporation for $1.0 billion in 2012. He served as President and Chief Executive Officer of Oak Valley Resources, LLC from its formation in December 2012 until the closing of its strategic combination with Earthstone Energy, Inc. (“Earthstone”) in December 2014. Since December 2014, Mr. Lodzinski has served as Chairman, President and Chief Executive Officer of Earthstone. He holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

The board of directors, in reviewing and assessing Mr. Lodzinski’s contributions to the board, determined that his industry experience, intimate knowledge of the oil and gas industry, and prior roles in managing publicly traded oil and gas companies provide significant contributions to the board of directors.

Ben T. Morris has served as a director and a member of our audit and compensation committees since the closing of the merger on September 10, 2014. He has served as a director of Yuma Co. since July 2011. He has an extensive financial background, with over 20 years of experience in many aspects of the financial sector. He began his career as an accountant at Price Waterhouse & Co. in 1967 and in 1973 joined Mid American Oil and Gas Inc. as CFO and later became President of the company. From 1980 to 1986, Mr. Morris served as COO of Tatham Corp., a privately-held oil and gas company. He is a retired CEO of the Sanders Morris Harris Group, a financial services and wealth management company he co-founded in 1987 and is still employed by the firm currently. Since August 2014, Mr. Morris has served as a director of Gulfport Energy, Inc., where he is a member of the audit committee and its nominating and corporate governance committee. Mr. Morris has served on the boards of several public companies including Capital Title Group (1998-2006); American Equity Investment Life Holding Company (1997-2006); and Tyler Technologies, Inc. (2002-2005), where he served as chairman of the audit committee. Mr. Morris earned a B.B.A. degree from the University of North Texas.

The board of directors, in reviewing and assessing the contributions of Mr. Morris to the board, determined that his past experience make him uniquely positioned to provide the board with insight and advice on a full range of strategic, financial, and governance matters.

Richard K. Stoneburner has served as a director and member of our compensation committee since the closing of the merger on September 10, 2014. He has served as a director of Yuma Co. since November 2013. He began his career as a geologist in 1977. Mr. Stoneburner joined Petrohawk Energy in 2003, where he led Petrohawk’s exploration program from 2005 to 2007 prior to serving as the company’s President and COO from 2007 to 2011. When BHP Billiton acquired Petrohawk in 2011, he was appointed President of the North America Shale Production Division where he managed operations in the Fayetteville Shale, the Haynesville Shale, the Eagle Ford Shale, and the Permian Basin divisions. Mr. Stoneburner currently serves on the Board of Directors of Tamboran Resources Limited and serves as a Managing Director to the private equity firm Pine Brook Partners. Prior to his appointment as Director, Mr. Stoneburner was a Board Advisor to Yuma Co. from July 2013 through November 2013. Mr. Stoneburner has a bachelor's degree in geology from the University of Texas and a master's degree in geological sciences from Wichita State University.

The board of directors, in reviewing and assessing Mr. Stoneburner's contributions to the board, determined that his prior industry experience ranging from staff geologist, corporate owner, exploration manager to C-level executive, his leading role in exploring for and developing some of the most successful resource plays in the United States; his significant experience in the challenges of resource play operations and development; and playing a key role in implementing a comprehensive health, safety, environment and community management system for unconventional shale plays while at BHP Billiton Petroleum provide significant contributions to the board of directors.

Corporate Code of Business Conduct and Ethics

Our board adopted a Corporate Code of Business Conduct and Ethics ("Code of Ethics"), which provides general statements of our expectations regarding ethical standards that we expect our directors, officers and employees to adhere to while acting on our behalf. Among other things, the Code of Ethics provides that:

- we will comply with all laws, rules and regulations;
- our directors, officers, and employees are to avoid conflicts of interest and are prohibited from competing with the Company or personally exploiting our corporate opportunities;
- our directors, officers, and employees are to protect our assets and maintain our confidentiality;
- we are committed to promoting values of integrity and fair dealing; and
- we are committed to accurately maintaining our accounting records under generally accepted accounting principles and timely filing our SEC periodic reports and tax returns.

Our Code of Ethics also contains procedures for employees to report, anonymously or otherwise, violations of the Code of Ethics.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, requires our directors and certain executive officers, and persons who beneficially own more than ten percent of our common stock, to file initial reports of ownership and reports of changes in ownership of our common stock and our other equity securities with the SEC. As a practical matter, we assist our directors and officers by monitoring transactions and completing and filing Section 16 reports on their behalf. Based solely on a review of the copies of such forms in our possession and on written representations from reporting persons, we believe that during 2015 all of our named executive officers, directors and greater than ten percent holders filed the required reports on a timely basis under Section 16(a) of the Exchange Act.

Shareholder-Recommended Director Candidates

Our board is responsible for identifying individuals qualified to become board members and nominees for directorship are selected by the board. Although the board is willing to consider candidates recommended by our shareholders, it has not adopted a formal policy with regard to the consideration of any director candidates recommended by our shareholders. The board believes that a formal policy is not necessary or appropriate because of the small size of the board and because the current board already has a diversity of business background and industry experience. Our board will consider director candidates recommended by shareholders who are highly qualified in terms of business experience and be both willing and expressly interested in serving on the board. Shareholders recommending candidates for consideration should send their recommendations, including the candidate's name, address, principal occupation, number of shares of common stock held by the proposed director candidate, and the recommending shareholder's name, address and number of shares of common stock held, and any other information about the candidate's qualifications to Yuma Energy, Inc., Attn: President, 1177 West Loop South, Suite 1825, Houston, Texas 77027. Submissions must include sufficient biographical information concerning the recommended individual, including age, educational background, employment history for at least the past five years indicating employer's name and description of the employer's business, and any other biographical information that would assist the Board in determining the qualifications of the individual. The board will consider all candidates, whether recommended by shareholders or members of management. The board will consider recommendations received by a date not later than 120 calendar days before the date our proxy statement was released to shareholders in connection with the prior year's annual meeting for nomination at that annual meeting. The board will consider nominations received beyond that date at the annual meeting subsequent to the next annual meeting.

Board Committees

To assist it in carrying out its duties, the board has delegated certain authority to an Audit Committee and a Compensation Committee as the functions of each are described below. Each member of the Audit and Compensation Committees has been determined by the board to be "independent" for purposes of the listing standards of NYSE MKT and the rules of the SEC, including the heightened "independence" standard required for members of the Audit Committee. Additionally, our board has determined that each member of the Compensation Committee is an "outside director" as defined for purposes of Section 162(m) of the Code, and is a "Non-Employee Director" as defined in Rule 16b-3 under the Exchange Act.

Audit Committee. The Audit Committee provides oversight of the Company's accounting policies, internal controls, financial reporting practices and legal and regulatory compliance. Among other things, the Audit Committee: appoints the independent auditor and evaluates its independence and performance; maintains a line of communication between the Board, the Company's financial management and the independent auditor; and oversees compliance with the Company's policies for conducting business, including ethical business standards. Our board of directors has determined that Mr. Morris qualifies as an "audit committee financial expert" as that term is defined in the listing standards of NYSE MKT and the applicable rules of the SEC. In 2015, the Audit Committee held five meetings. The members of our Audit Committee during 2015 were Ben T. Morris (Chairperson), James W. Christmas and Frank A. Lodzinski.

Compensation Committee. The Compensation Committee oversees the development and administration of the Company's compensation policies and programs. The primary function of this Committee is to review and approve executive compensation and benefit programs. Additionally, this Committee approves the compensation of our named executive officers, including the Chief Executive Officer. The Compensation Committee has retained a compensation consultant to assist the Committee in oversight and review of compensation policies of the Company. Our Chief Executive Officer is expected to recommend to the Compensation Committee the compensation for our other named executive officers. During 2015, the Compensation Committee held two meetings. The members of our Compensation Committee during 2015 were Richard K. Stoneburner (Chairperson), James W. Christmas and Ben T. Morris.

Controlled Company

Our board has determined that we are a "controlled company" as defined under the corporate governance rules of the NYSE MKT since more than 50% of our issued and outstanding common stock is held by Sam L. Banks, our Chairman, President and Chief Executive Officer. As a "controlled company," we are exempted from certain rules otherwise applicable to companies whose securities are listed on the NYSE MKT, including: (a) the requirement that the Company has a majority of independent directors; (b) the requirement that nominations to the board be either selected or recommended by a nominating committee consisting solely of independent directors; and (c) the requirement that the Company's officers' compensation be either determined or recommended by a compensation committee consisting solely of independent directors.

Item 11. Executive Compensation.

Summary Compensation Table

The following table presents, for the years ended December 31, 2015 and 2014, the compensation of Mr. Sam L. Banks, our principal executive officer, and Messrs. McKinney and Jacobs, our two most highly-compensated executive officers (other than the principal executive officer) who were serving as executive officers (collectively, the "named executive officers" or "NEOs") as of December 31, 2015. We have employment contracts with each of our named executive officers. There has been no compensation awarded to, earned by or paid to any employees required to be reported in any table or column in the fiscal years covered by any table, other than what is set forth in the following table.

Name and Principal Position	Year	Salary ($)		Bonus ($)	Stock Awards ($) (1)	Option Awards ($) (2)	All Other Compensation ($) (3)	Total ($)
Sam L. Banks	2015	425,000		4,304	411,040	181,449	708,270	1,730,063
Principal Executive Officer	2014	141,667	(4)	-	-	-	368,182	509,849
James J. Jacobs (5)	2015	251,042		101,601	193,279	85,321	-	631,243
Chief Financial Officer, Treasurer and Corporate Secretary								
Paul D. McKinney	2015	350,000		50,000	676,304	149,312	-	1,225,616
Executive Vice President – Chief Operating Officer								

(1) Represents the grant date fair value of awards granted during the indicated year, as determined in accordance with ASC Topic 718. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. Please see the discussion of the assumptions made in the valuation of these awards in Part II, Item 8. Notes to the Consolidated Financial Statements, Note 11—Stock-Based Compensation. Generally, the full grant date fair value is the amount that we would expense in our financial statements over the award's vesting schedule. These amounts reflect our accounting expense, and do not correspond to the actual value that will be recognized by the named executive officers.

(2) The amounts for stock appreciation rights awards represent the estimated fair value of stock appreciation rights at the date of grant. Fair value of the stock appreciation rights is determined by the Black-Scholes option pricing model in accordance with FASB ASC Topic 718. For a discussion of valuation assumptions used, in Part II, Item 8. Notes to the Consolidated Financial Statements, Note 11—Stock-Based Compensation. The terms of the stock appreciation rights grant are set forth below in the table "Outstanding Equity Awards at 2015 Fiscal Year-End."

(3) The amounts reported in this column include revenues received by Mr. Banks from overriding royalty interests pursuant to the royalty plan (as discussed below) from the date of the closing of the merger through December 31, 2014 and for the year ended December 31, 2015.

(4) Information for Mr. Banks is included for the period after September 10, 2014, the date he became an employee and through December 31, 2014.

(5) Mr. Jacobs became an executive officer on December 15, 2015; however, his full year compensation is included in the table.

Narrative Disclosure to the Summary Compensation Table

The following discussion provides information about the compensation program for our named executive officers and is intended to place in perspective the information contained in the executive compensation tables.

Compensation Philosophy and Objectives. We operate in a highly competitive and challenging environment and must attract, motivate and retain highly talented individuals with the requisite technical and managerial skills to implement our business strategy. The objectives of our compensation program are to:

- help to attract and retain highly talented individuals to contribute to the Company's progress, growth and profitability by being competitive with compensation paid to persons having similar responsibilities and duties in other companies in the same industry;
- align the interests of the individual with those of our shareholders to encourage long-term value creation;
- be directly tied to the attainment of our annual performance targets and reflect individual contribution thereto; and
- reflect the unique qualifications, skills, experience and responsibilities of each individual.

Elements of Our Compensation Program – Base Salary. Base salary is the principal fixed component of our compensation program. It provides our named executive officers with a regular source of income to compensate them for their day-to-day efforts in managing the Company. Base salary is primarily used to attract and retain highly talented individuals. Base salary varies depending on the named executive officer's experience, responsibilities, education, professional standing in the industry, changes in the competitive marketplace and the importance of the position to the Company.

Short-Term Incentives. Short-term incentive compensation is the short-term variable portion of our compensation program and is based on the principle of pay-for-performance. The objective of short-term incentives is to reward our named executive officers based on the performance of the Company as a whole and the contributions of the individual named executive officer in relation to our success.

Long-Term Incentives. Long-term incentives are provided to our named executive officers under our 2014 Long-Term Incentive Plan (the "2014 Plan"), which was approved by our shareholders in September 2014. These incentives are intended to align the interests of shareholders with employees by providing employees with incentive to perform technically and financially in a manner that promotes total shareholder return. Furthermore, we believe that long-term incentives create an incentive for future performance and create a retention incentive. In determining long-term incentives, the Compensation Committee considers a named executive officer's potential for future successful performance and leadership as part of the executive management team, taking into account past performance and leadership as a key indicator.

Under our 2014 Plan, the Compensation Committee has the flexibility to choose between a number of forms of long-term incentive compensation, including stock options, stock appreciation rights, restricted stock awards, performance units, performance shares, or other incentive awards.

Other Benefits. All employees may participate in our 401(k) Retirement Savings Plan ("401(k) Plan") established many years ago. Each employee may make before-tax contributions in accordance with the limits of the Internal Revenue Service. We provide the 401(k) Plan to help our employees attain financial security by providing them with a program to save a portion of their cash compensation for retirement in a tax efficient manner. Our matching contribution is an amount equal to 100% of the employee's elective deferral contribution not to exceed 4.0% of the employee's compensation; provided, however, that the matching contribution does not apply to our highly compensated employees, including our named executive officers.

All full time employees, including our named executive officers, may participate in our health and welfare benefit programs, including medical, dental and vision care coverage, disability insurance and life insurance.

Roles of our CEO and the Compensation Committee. Our Compensation Committee is comprised solely of independent directors and has overall responsibility for the compensation of our named executive officers. The

Compensation Committee monitors our director and named executive officer compensation and benefit plans, policies and programs to insure that they are consistent with our compensation philosophy and objectives, along with our corporate governance guidelines. Our President and Chief Executive Officer, Mr. Banks, makes recommendations to the Compensation Committee regarding the base salary, short-term and long-term incentive compensation with respect to the named executive officers (other than himself) based on his analysis and assessment of their performance. Such officers are not present at the time of these deliberations. The Compensation Committee, in its discretion, may accept, modify or reject any or all such recommendations. The Compensation Committee independently determines the salary, short-term and long-term incentive compensation for our President and Chief Executive Officer with limited input from him. The Compensation Committee makes periodic awards to our named executive officers under our 2014 Plan.

Other Compensation Practices – Accounting and Tax Considerations. Our Compensation Committee reviews and takes into account current tax, accounting and securities regulations as they relate to the design of our compensation programs and related decisions.

Stock Ownership Guidelines and Hedging Prohibition. We do not currently have ownership requirements or a stock retention policy for our named executive officers or non-employee directors. Our board has adopted a policy restricting all employees, including our named executive officers, and members of the board from engaging in any hedging transactions with respect to our common stock held by them, which includes the purchase of any financial instrument (including prepaid variable forward contracts, equity swaps, collars and exchange funds) designed to hedge or offset any decrease in the market value of such equity securities. The board has also adopted a policy restricting our named executive officers and members of the board from pledging, or using as collateral, our common stock in order to secure personal loans or other obligations, which includes holding shares of our common stock in a margin account.

We will continue to periodically review best practices and re-evaluate our position with respect to stock ownership guidelines and hedging prohibitions.

Clawback Provisions. Although we do not presently have any formal policies or practices that provide for the recovery of prior incentive compensation awards that were based on financial information later restated as a result of the Company's material non-compliance with financial reporting requirements, in such event we reserve the right to seek all recoveries currently available under law. The Compensation Committee has included a provision into our equity grant agreements whereby the equity grants to named executive officers are subject to any clawback policies the Company may adopt which may result in the reduction, cancellation, forfeiture or recoupment of such grants if certain specified events occur, including, but not limited to, an accounting restatement due to any material noncompliance with financial reporting regulations by the Company.

Overriding Royalty Interest Plan. Our overriding royalty interest plan (the "royalty plan") was established in 1983 with the formation of the predecessor of one of our subsidiaries for the issuance of a portion of certain overriding royalty interests developed and leased on our prospects from time to time by us to our employees and management. The purpose of the royalty plan is to provide an employee incentive plan to reward the successful generation and drilling of our prospects and provide for employee retention. The royalty plan is administered and interpreted by our Compensation Committee. As of December 31, 2015, none of our named executive officers were eligible to receive grants of overriding royalty payments under the royalty plan other than what had already vested on certain legacy projects in accordance with our chief executive officer's employment agreement.

From time to time, we reserve approximately 3.5% of our net revenue interest (based on 100% of the net revenue interest) on our generated prospects as a pool to satisfy grants of overriding royalties under the royalty plan. This amount is subject to the approval of our partners in the applicable prospects via absorbing their proportionate share of the overriding royalty interests. The amount of each actual grant is typically subject to the terms of applicable employment agreements and the vesting schedules included therein, unless otherwise determined.

Notwithstanding anything to the contrary, the royalty plan provides that nothing in it prohibits us from operating our business in the ordinary course. Also, we have no obligation to conduct any drilling operations or take any other action upon or with respect to any property subject to the royalty plan or to continue to operate any well or to operate or maintain in force any lease. In addition, we have the right at any time to surrender, abandon or otherwise terminate any such lease in whole or in part without any liability to any royalty plan participant.

Working Interest Incentive Plan. Our working interest incentive plan (the "working interest plan") was originally adopted in 1983, amended in August 2011, and was terminated in September 2015.

The working interest plan was administered and interpreted by the board. The board had the power to take any and all action the board deemed necessary or advisable for the proper operation or administration of the working interest plan. From August 15, 2011 through the termination of the working interest plan on September 21, 2015, the board approved all property acquisitions under the working interest plan.

When we acquired certain real property interests upon which we generated one or several oil and natural gas prospects, or we acquired a working interest in existing oil and natural gas prospects, once we generated a drillable prospect, or upon the acquisition of a working interest in an existing prospect from an unaffiliated third party, Mr. Banks had the option to acquire from us, or such unaffiliated third party directly, a working interest in such prospects in an amount up to 2.5% of our working interest. In lieu of acquiring a working interest in the prospects from us, Mr. Banks had the right, at his election, to participate with us in any production acquisitions in which we undertake in an amount up to 2.5% (previously 5.0%) of the working interest acquired. The terms under which Mr. Banks acquired any interests were no better than the terms promoted to unaffiliated third parties who were drilling participants in our generated prospects.

The purchase price for any interests acquired from us was determined using the same cost basis as we acquired such interests. The purchase price for any interests acquired from a third party in a transaction in which Mr. Banks participated was determined in arm's length negotiations. The pricing and payment terms for any interests acquired were no better than the terms promoted to unaffiliated third parties who were drilling participants in our generated prospects. Mr. Banks paid the purchase price for any interests acquired from us in cash at the closing of the acquisition, and he was responsible for obtaining any financing required to purchase any interests. In no event did we advance the purchase price for any acquisition, assist Mr. Banks in obtaining financing, or otherwise arrange such financing or any other extension of credit for Mr. Banks in connection with the working interest plan, and did not provide any guarantee or other credit support to Mr. Banks.

Also, see Item 13. "Certain Relationships, Related Transactions and Director Independence," for additional information about Mr. Banks' participation in the working interest plan.

Outstanding Equity Awards

The following table provides information concerning unvested restricted stock awards and equity incentive plan awards for our named executive officers as of December 31, 2015.

Outstanding Equity Awards at 2015 Fiscal Year-End

	Option Awards				Stock awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable (1)	Option Exercise Price ($)	Option Expiration Date	Number of shares or units of stock that have not vested (#) (2)	Market value of shares of units of stock that have not vested ($) (3)	Equity incentive plan awards: Number of unearned shares, units or other rights that	Equity incentive plan awards: market or payout value of unearned shares, units or

								have not vested (#)	other rights that have not vested ($)
Sam L. Banks									
	-	-	-	-	772,534	$	146,781	-	-
	-	570,595	$ 0.605	08/18/2022	-		-	-	-
James J. Jacobs									
	-	-	-	-	385,711	$	73,285	-	-
	-	268,305	$ 0.605	08/18/2022	-		-	-	-
Paul D. McKinney									
	-	-	-	-	566,088	$	107,557	-	-
	-	469,534	$ 0.605	08/18/2022	-		-	-	-

(1) The table below shows the vesting dates for the respective unvested stock appreciation rights awards listed in the above Outstanding Equity Awards at 2015 Fiscal Year-End Table:

Vesting Date	Mr. Banks	Mr. Jacobs	Mr. McKinney
May 31, 2016	190,199	89,435	156,512
May 31, 2017	190,198	89,435	156,511
May 31, 2018	190,198	89,435	156,511

(2) The table below shows the vesting dates for the respective unvested restricted stock awards listed in the above Outstanding Equity Awards at 2015 Fiscal Year-End Table:

Vesting Date	Mr. Banks	Mr. Jacobs	Mr. McKinney
January 1, 2016	37,867	14,137	-
May 31, 2016	232,268	109,217	156,199
July 14, 2016	-	29,789	-
October 15, 2016	-	-	48,747
January 1, 2017	37,867	14,136	-
May 31, 2017	232,266	109,216	156,198
October 15, 2017	-	-	48,746
May 31, 2018	232,266	109,216	156,198

(3) Calculated based upon the closing market price of our common stock as of December 31, 2015, the last trading day of our 2015 fiscal year ($0.19) multiplied by the number of unvested restricted stock awards at year end.

Employment Contracts and Termination of Employment

Messrs. Banks, Jacobs and McKinney (collectively, the "officers") entered into employment agreements with Yuma Co. on October 1, 2012, July 15, 2013, and October 14, 2014, respectively, and the Company assumed the obligations under such employment agreements in connection with the closing of the merger.

Under the terms of the employment agreements, Messrs. Banks, Jacobs and McKinney currently receive annual base salaries in the amount of $425,000, $275,000, and $350,000, respectively, subject to any increase the Compensation Committee may deem appropriate from time to time. In addition, the officers are eligible to receive one or more annual cash bonuses and grants of stock options, stock appreciation rights, restricted stock or other equity-related awards from our equity compensation plans, as determined by the Compensation Committee. Each of the employment agreements of Messrs. Banks and Jacobs is on a month-to-month basis and may be terminated with 60 days' notice. Mr. McKinney's employment agreement provides that it may not be terminated during the initial term of two years beginning on October 14, 2014, except for his resignation due to illness, death or termination by the Company for cause (as defined in the employment agreement).

The employment agreements include severance provisions that apply upon certain involuntary terminations of employment. As a condition to the payment of any severance benefit described below, we may require the officer to execute and not revoke a release of claims in favor of us. The employment agreements also contain certain restrictive covenants, including the obligation not to compete against the Company and a confidentiality requirement. In the event the officer violates these restrictive covenants, we may cease paying all severance benefits to the officer and may recover an amount equal to any severance benefits previously paid to the officer under the agreement.

The employment agreements provide that in the event of a termination of employment by the Company for cause or by the officer without good reason, the officer will be entitled to accrued but unpaid base salary and benefits through the date of termination but will forfeit any other compensation from the Company.

In the event that Mr. Banks' employment is terminated by him for good reason (as defined in his employment agreement), then he will be entitled to receive (i) any earned but unpaid bonus, (ii) continued payments of base salary for a period of 24 months, assuming continued compliance with restrictive covenants and execution and non-revocation of a release of claims, and (iii) either the provision of continued participation in our health insurance plans or the payment of Mr. Banks' premiums for continued health insurance pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985 ("COBRA"), for a period of 24 months.

The employment agreements also contain customary confidentiality and non-solicitation provisions. The non-solicitation provisions of the employment agreements prohibit the officers from soliciting for employment any employee of the Company or any person who was an employee of the Company. This prohibition applies during the officer's employment with the Company and for two years following the termination of his employment and extends to offers of employment for his own account or benefit or for the account or benefit of any other person, firm or entity, directly or indirectly.

Please see the section titled "Potential Payments Triggered Upon a Change in Control."

Potential Payments Triggered Upon a Change in Control

The amounts shown in the following table reflect the potential value to our named executive officers, as of December 31, 2015, of cash payments under such named executive officer's employment agreement, unvested restricted stock awards and unvested stock appreciation rights where the vesting may accelerate upon a change in control of the Company. The cash compensation and the equity awards in the table below assume that the employment of the named executive is terminated by the named executive officer for good reason in accordance with the named executive officer's employment agreement after a change in control (i.e. a double trigger). Consistent with SEC requirements, these estimated amounts have been calculated as if the change in control had occurred as of December 31, 2015, the last business day of 2015, and using the closing market price of our common stock on December 31, 2015 ($0.19 per share). The amounts below are estimates of the incremental amounts that would be received upon a change in control; the actual amount could be determined only at the time of any actual change in control.

Estimated Potential Payments Triggered Upon a Change in Control

Name	Cash Compensation ($)	Unvested Stock Appreciation Rights Awards at 12/31/2015 (#)	Value (Based on Closing Price of Stock at 12/31/2015) ($) (1)	Unvested Restricted Stock Awards at 12/31/2015 (#)	Value (Based on Closing Price of Stock at 12/31/2015) ($)	Total ($)
Sam L. Banks	$ 850,000	570,595	-	772,534	$ 146,781	$ 996,781
James J. Jacobs	-	268,305	-	385,711	$ 73,285	$ 73,285
Paul D. McKinney	-	469,534	-	566,088	$ 107,557	$ 107,557

(1) The stock appreciation rights have an exercise price of $0.605 per share and were underwater as of December 31, 2015 and accordingly had no value.

Compensation Committee Interlocks and Insider Participation

The members of our Compensation Committee during 2015 were Messrs. Stoneburner, Christmas and Morris. There are no members of our Compensation Committee who were officers or employees of the Company or any of our subsidiaries during fiscal year 2015. No members were formerly officers of the Company or had any relationship otherwise requiring disclosure hereunder. During fiscal year 2015, no interlocking relationships existed between any of our named executive officers or members of our board or Compensation Committee, on the one hand, and the executive officers or members of the board of directors or compensation committee of any other entity, on the other hand.

Director Compensation

Directors who are employees of the Company receive no additional compensation for serving on the Board. Non-employee directors are compensated for their service on the Board as described below.

Retainer Fees

The Compensation Committee reviews our director compensation periodically and recommends changes to the Board, when it deems them appropriate. The following table describes the components of compensation for non-employee directors in effect during 2015:

Compensation Element	Compensation Program
Annual Cash Retainer	$ 40,000
Annual Equity Grant	$ 50,000
Audit Committee Chair Fee	$ 15,000
Compensation Committee Chair Fee	$ 8,000

Restricted Stock Awards

The Company did not grant any equity awards to the non-employee directors during 2015.

Director Compensation in 2015

The following table sets forth the aggregate compensation paid to our non-employee directors during the year ended December 31, 2015:

Name	Fees Earned or Paid In Cash ($)	Total ($)
James W. Christmas	40,000	40,000
Frank A. Lodzinski	40,000	40,000
Ben T. Morris	55,000	55,000
Richard K. Stoneburner	48,000	48,000
Richard W. Volk (1)	17,692	17,692

(1) Mr. Volk retired from the board effective at the 2015 annual meeting of shareholders.

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

The following table includes all holdings of common stock, no par value per share, of the Company, as of March 29, 2016 of our directors and our named executive officers, our directors and named executive officers as a group, and all those known by us to be beneficial owners of more than five percent of our common stock. Unless otherwise noted, the mailing address of each person or entity named below is 1177 West Loop South, Suite 1825, Houston, Texas 77027.

Name	Common Stock (1)	Percent (2)	
Named Executive Officers:			
Sam L. Banks (3)	41,809,419	57.6	%
James J. Jacobs (3)	456,371	*	
Paul D. McKinney (3)	659,835	*	
Non-Management Directors:			
James W. Christmas (3)	950,480	1.3	%
Frank A. Lodzinski (4)	70,679	*	
Ben T. Morris	169,124	*	
Richard K. Stoneburner (3)	8,331	*	
Officers and Directors as a Group (seven persons): (3)	44,124,239	60.0	%
Beneficial Owners of More than Five Percent:			
Sanders Morris Harris Inc. (5)	7,428,668	10.3	%

* Less than one percent.

(1) This column lists beneficial ownership of voting securities as calculated under SEC rules. Otherwise, except to the extent noted below, each director, named executive officer or entity has sole voting and investment power over the shares reported. None of the shares are pledged as security by the named person.

(2) The percentage is based upon 71,911,361 shares of common stock of the Company issued and outstanding on March 29, 2016.

(3) Includes unvested shares of restricted stock subject to forfeiture for Mr. Banks – 734,667; Mr. Jacobs – 371,574; Mr. McKinney – 566,088; Mr. Christmas – 2,777; Mr. Stoneburner – 2,777, and all directors and named executive officers as a group — 1,677,883.

(4) Includes 62,348 shares held in the name of Azure Energy, LLC (“Azure”). Mr. Lodzinski disclaims beneficial ownership of the shares held by Azure, except to the extent of his pecuniary interests therein.

(5) Based on the Schedule 13G/A dated November 6, 2015 (filed: December 11, 2015) which indicates that it was filed by Sanders Morris Harris LLC (“SMH”). According to such Schedule 13G, SMH, in its capacity as investment adviser and broker-dealer, may be deemed to beneficially own 7,428,668 shares, and has sole voting power over no shares, shared voting power over no shares, sole dispositive power over no shares, and shared dispositive power over 7,428,668 shares. The principal place of business for SMH is 600 Travis Street, Houston, Texas, 77002.

Equity Compensation Plan Information

The following table provides information related to our common stock which may be issued under our existing equity compensation plans as of December 31, 2015, including the Yuma Energy, Inc. 2014 Long-Term Incentive Plan (the “2014 Plan”), the Pyramid Oil Company 2006 Equity Incentive Plan (the “2006 Plan”), plus the Yuma Co. 2011 Stock Option Plan (the “Yuma Co. Plan”) and stock awards outstanding thereunder which we assumed in connection with our acquisition of Yuma Co. in September 2014:

PLAN CATEGORY	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column a) (c)
Equity compensation plans approved by security holders: (1)(2)	2,017,419	$ 0.8426	4,307,672
Equity compensation plans not approved by security holders: (3)	249,921 (4)	-	-
Total	2,267,340	$ 0.8426	4,307,672

(1) The 2014 Plan was adopted by our shareholders in September 2014.

(2) The 2006 Plan was adopted by our shareholders in June 2006. After the closing of the merger, the board resolved to not issue any additional awards under the 2006 Plan.

(3) We assumed the Yuma Co. Plan and the outstanding stock awards under the Yuma Co. Plan in connection with the closing of the merger in September 2014. After the closing of the merger, the board resolved to not issue any additional awards under the Yuma Co. Plan. We assumed 2,359,361 restricted shares of common stock in connection with the closing of the merger under the Yuma Co. Plan. Also, we assumed 95,424 restricted stock units in connection with the closing of the merger under the Yuma Co. Plan. Each restricted stock unit represents a contingent right to receive one share of our common stock upon vesting.

(4) Includes 169,643 shares of restricted stock not yet vested and 80,278 restricted stock units not yet vested.

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

Working Interest Incentive Plan

The following table sets forth, with respect to Mr. Banks' working interests acquired under the working interest plan (since the adoption of the plan in 1983 by the predecessor of our subsidiary, Yuma Co.), the oil, natural gas and natural gas liquids revenues he received, lease operating expenses he paid, the resulting net cash flow before capital expenditures, capital expenditures he paid and net cash flow after capital expenditures during each of the years ended December 31, 2015 and 2014.

	Years Ended December 31,	
	2015	2014
Natural gas and oil revenues	$414,439	$819,300
Lease operating expenditures	(499,750)	(672,429)
Net cash flow	(85,311)	146,871
Capital expenditures	(84,813)	(581,163)
Net after capital expenditures and before income taxes	$(170,124)	$(434,292)

The foregoing information has been derived solely from our Company records. Accordingly, it may not include all revenues and expenses for the working interest plan interests that are not operated by us. Mr. Banks' working interests are his personal assets and we do not restrict sales, dispositions or financing transactions involving our working interests that we previously assigned to him. Mr. Banks pays us for lease operating expenses and capital expenditures related to his working interests acquired under the working interest plan promptly upon receipt of each invoice. As of the years ended December 31, 2015 and 2014, Mr. Banks had outstanding payables to us for such working interests in the amounts of $60,403 and $174,720, respectively, and each such payable was promptly paid upon receipt of the invoices. For more information about the working interest plan, see the "Executive Compensation – Working Interest Incentive Plan" section above.

Working Interest Owner

Mr. Christmas, one of our directors, owns a working interest in two of our wells, which we operate under a standard joint operating agreement. During the years ended December 31, 2015 and 2014, Mr. Christmas received oil and gas revenues, net of severance taxes and transportation costs, totaling $18,623 and $147,038, respectively, from the Company attributable to such working interests and during the years ended December 31, 2015 and 2014, Mr. Christmas incurred lease operating expenses and capital expenditures on such working interests of $88,717 and $821,422, respectively.

Policies and Procedures for Approval of Related Party Transactions

Our officers and directors are required to obtain Audit Committee approval for any proposed related party transactions. In addition, our Code of Ethics requires that each director, officer and employee must do everything he or she reasonably can to avoid conflicts of interest or the appearance of conflicts of interest. Our Code of Ethics states that a conflict of interest exists when an individual's private interest interferes in any way or even appears to interfere with our interests and sets forth a list of broad categories of the types of transactions that must be reported to our board. Under our Code of Ethics, we reserve the right to determine when an actual or potential conflict of interest exists and then to take any action we deem appropriate to prevent the conflict of interest from occurring.

Director Independence

The current Board consists of five directors, one of whom is currently employed by the Company (Mr. Banks). In March 2016, the board conducted an annual review and affirmatively determined that our non-employee directors (Messrs. Christmas, Lodzinski, Morris and Stoneburner) are “independent” as that term is defined in the listing standards of the NYSE MKT. The board made a subjective determination as to each independent director that no relationship exists which, in the opinion of the board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. In making these determinations, the board reviewed and discussed information provided by the board and the Company with regard to each director’s business and personal activities as they may relate to the Company and its management. Further, the board determined that Mr. Banks is not independent because he is the President, Chief Executive Officer and majority shareholder of the Company.

Item 14. Principal Accounting Fees and Services.

Fees Paid to Grant Thornton LLP and SingerLewak LLP

The following is a summary and description of fees for services provided by Grant Thornton LLP ("Grant Thornton") in 2015 and 2014, and SingerLewak LLP ("SingerLewak") in 2014.

	2015	2014	
Services	Grant Thornton	Grant Thornton	SingerLewak
Audit Fees (1)	$329,796	$566,973	$ 23,895
Audit-Related Fees (2)	-	-	-
Tax Fees	-	-	-
All Other Fees	-	-	-
Total	$329,796	$566,973	$ 23,895

(1) Audit Fees include professional services for the audit of our annual financial statements, reviews of the financial statements included in our Form 10-Q filings, and services normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-Related Fees comprise fees for professional services reasonably related to the performance of the audit or review of the Company's financial statements.

Audit Committee Pre-Approval Policies and Procedures

To help assure independence of the independent auditor, the Audit Committee has established a policy whereby all audit, review, attest and non-audit engagements of the principal auditor or other firms must be approved in advance by the Audit Committee; provided, however, that de minimis non-audit services may instead be approved in accordance with applicable SEC rules. This policy is set forth in our Audit Committee Charter. Of the fees shown in the table below, which were paid to our independent auditor, 100% were approved by the Audit Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

Form 10-K for the fiscal year ended December 31, 2015.

Exhibit No.	Description	Form	Incorporated by Reference 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		
2.2	Agreement and Plan of Merger and Reorganization dated as of February 10, 2016, by and among Yuma Energy, Inc., Yuma Delaware Merger Subsidiary, Inc., Yuma Merger Subsidiary, Inc. and Davis Petroleum Acquisition Corp.	8-K	001-32989	2.1	February 16, 2016		
3.1	Restated Articles of Incorporation dated September 10, 2014.	8-K	001-32989	3.1	September 16, 2014		
3.1(a)	Certificate of Amendment to the Restated Articles of Incorporation dated June 9, 2015.	8-K	001-32989	3.1	June 15, 2015		
3.2	Certificate of Determination of Rights, Preferences, Privileges and Restrictions of 9.25% Series A Cumulative	8-A	001-32989	3.2	October 20, 2014		

	Redeemable Preferred Stock of Yuma Energy, Inc.				
3.3	Amended and Restated Bylaws of Yuma Energy, Inc.	S-3	333-192094	4.2	November 5, 2013
3.3(a)	First Amendment to the Amended and Restated Bylaws dated June 9, 2015.	8-K	001-32989	3.2	June 15, 2015
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 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.	S-4	333-197826	10.4	August 4, 2014
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 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.	8-K	001-32989	10.1	October 14, 2014
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, 2015
10.1(g)	Seventh Amendment to Credit Agreement effective as of April 7, 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	April 22, 2015
10.1(h)	Eighth Amendment to Credit Agreement effective as of July 27, 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	August 12, 2015
10.1(i)	Waiver, Borrowing Base Redetermination and Ninth Amendment to Credit Agreement effective as of December 30, 2015, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as	8-K	001-32989	10.1	January 5, 2016

	Administrative Agent and Issuing Bank, and each of the lenders party thereto.				
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, 2009
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 15, 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		8-K	001-32989	10.4	

	Indemnity Agreement, dated as of September 30, 2013, between the Registrant and John H. Alexander.				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
10.25†	Form of Restricted Stock Award Agreement (Employees).	8-K	001-32989	10.1	June 15, 2015

10.26†	Form of Restricted Stock Award Agreement (Directors).	8-K	001-32989	10.2	June 15, 2015		
10.27†	Form of Stock Appreciation Rights Award Agreement.	8-K	001-32989	10.1	August 24, 2015		
10.28†	Separation Agreement, General Release of Claims and Waiver dated December 15, 2015 between Yuma Energy, Inc. and Kirk F. Sprunger.	8-K	001-32989	10.1	December 21, 2015		
10.29	Voting Agreement dated as of February 10, 2016, by and among Yuma Energy, Inc., Yuma Delaware Merger Subsidiary, Inc. and each of the persons listed on Schedule A thereto.	8-K/A	001-32989	10.1	February 16, 2016		
10.30	Voting Agreement dated as of February 10, 2016, by and among Davis Petroleum Acquisition Corp. and the persons listed on Schedule A thereto.	8-K/A	001-32989	10.2	February 16, 2016		
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 29, 2016	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 29, 2016
/s/ James J. Jacobs James J. Jacobs	Chief Financial Officer, Treasurer and Corporate Secretary (Principal Financial Officer and Principal Accounting Officer)	March 29, 2016
/s/ James W. Christmas James W. Christmas	Director	March 29, 2016
/s/ Frank A. Lodzinski Frank A. Lodzinski	Director	March 29, 2016
/s/ Ben T. Morris Ben T. Morris	Director	March 29, 2016
/s/ Richard K. Stoneburner Richard K. Stoneburner	Director	March 29, 2016

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. (a California corporation) and subsidiaries (the "Company") as of December 31, 2015 and 2014, 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, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. The Company incurred net losses in each of the years ended December 31, 2015, 2014 and 2013, and as of December 31, 2015, the Company's current liabilities exceeded its current assets by $27.2 million. These conditions, along with other matters as set forth in Note 3, raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 3. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ GRANT THORNTON LLP

Houston, Texas
March 29, 2016

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$5,355,191	$11,558,322
Short-term investments	-	1,170,868
Accounts receivable, net of allowance for doubtful accounts:		
Trade	2,829,266	9,739,737
Officers and employees	75,404	316,077
Other	633,573	856,562
Commodity derivative instruments	2,658,047	3,338,537
Prepayments	704,523	782,234
Other deferred charges	415,740	342,798
Total current assets	12,671,744	28,105,135
OIL AND GAS PROPERTIES (full cost method):		
Not subject to amortization	14,288,716	25,707,052
Subject to amortization	204,512,038	186,530,863
	218,800,754	212,237,915
Less: accumulated depreciation, depletion and amortization	(117,304,945)	(103,929,493)
Net oil and gas properties	101,495,809	108,308,422
OTHER PROPERTY AND EQUIPMENT:		
Land, buildings and improvements	2,795,000	2,795,000
Other property and equipment	3,460,507	3,439,688
	6,255,507	6,234,688
Less: accumulated depreciation and amortization	(2,174,316)	(1,909,352)
Net other property and equipment	4,081,191	4,325,336
OTHER ASSETS AND DEFERRED CHARGES:		
Commodity derivative instruments	1,070,541	1,403,109
Deposits	264,064	264,064
Goodwill	-	5,349,988
Other noncurrent assets	38,104	262,200
Total other assets and deferred charges	1,372,709	7,279,361
TOTAL ASSETS	$119,621,453	$148,018,254

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

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS - CONTINUED

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of debt	$30,063,635	$282,843
Accounts payable, principally trade	7,933,664	25,004,364
Asset retirement obligations	70,000	-
Other accrued liabilities	1,781,484	1,419,565
Total current liabilities	39,848,783	26,706,772
LONG-TERM DEBT:		
Bank debt	-	22,900,000
OTHER NONCURRENT LIABILITIES:		
Asset retirement obligations	8,720,498	12,487,770
Deferred taxes	6,797,166	14,773,306
Restricted stock units	-	71,569
Other liabilities	30,090	22,451
Total other noncurrent liabilities	15,547,754	27,355,096
EQUITY:		
Preferred stock	10,828,603	9,958,217
Common stock, no par value (300 million shares authorized, 71,834,617 and 69,139,869 issued)	141,858,946	137,469,772
Accumulated other comprehensive income	-	38,801
Accumulated earnings (deficit)	(88,462,633)	(76,410,404)
Total equity	64,224,916	71,056,386
TOTAL LIABILITIES AND EQUITY	$119,621,453	$148,018,254

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2015	2014	2013
REVENUES:			
Sales of natural gas and crude oil	$18,680,584	$38,659,392	$28,235,413
Net gains (losses) from commodity derivatives	5,038,826	3,398,518	(159,810)
Total revenues	23,719,410	42,057,910	28,075,603
EXPENSES:			
Marketing cost of sales	532,985	1,045,177	1,234,308
Lease operating	11,401,309	12,816,725	9,316,364
Re-engineering and workovers	555,539	3,084,972	2,521,707
General and administrative – stock-based compensation	2,289,311	3,388,321	452,058
General and administrative – other	7,434,304	8,156,077	4,536,506
Depreciation, depletion and amortization	13,651,207	19,664,991	12,077,368
Asset retirement obligation accretion expense	604,538	604,511	668,497
Goodwill impairment	5,349,988	-	-
Other	468,221	98,476	171,774
Total expenses	42,287,402	48,859,250	30,978,582
INCOME (LOSS) FROM OPERATIONS	(18,567,992)	(6,801,340)	(2,902,979)
OTHER INCOME (EXPENSE):			
Change in fair value of preferred stock derivative liability – Series A and Series B	-	(15,676,842)	(26,258,559)
Interest expense	(456,423)	(326,200)	(567,676)
Other, net	36,338	25,378	(240,617)
Total other income (expense)	(420,085)	(15,977,664)	(27,066,852)
NET INCOME (LOSS) BEFORE INCOME TAXES	(18,988,077)	(22,779,004)	(29,969,831)
Income tax expense (benefit)	(7,983,039)	(2,553,854)	3,080,272
NET INCOME (LOSS)	(11,005,038)	(20,225,150)	(33,050,103)
PREFERRED STOCK:			
Dividends paid in cash, perpetual preferred Series A	1,047,191	224,098	-
Dividends in arrears, perpetual preferred Series A	213,751	-	-
Accretion, Series A and Series B	-	786,536	1,101,972
Dividends paid in cash, Series A and Series B	-	445,152	145,900
Dividends paid in kind, Series A and Series B	-	4,133,380	5,412,281
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(12,265,980)	$(25,814,316)	$(39,710,256)
EARNINGS (LOSS) PER COMMON SHARE:			

Basic	$(0.17)	$(0.52)	$(0.97)
Diluted	$(0.17)	$(0.52)	$(0.97)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	71,013,717	49,678,444	41,074,953
Diluted	71,013,717	49,678,444	41,074,953

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31, 2015	2014	2013
NET INCOME (LOSS)	$(11,005,038)	$(20,225,150)	$(33,050,103)
OTHER COMPREHENSIVE INCOME (LOSS):			
Commodity derivatives sold	(119,917)	-	-
Less income taxes	(46,168)	-	-
Commodity derivatives sold, net of income taxes	(73,749)	-	-
Reclassification of (gain) loss on settled commodity derivatives	56,826	50	(374,099)
Less income taxes	21,878	19	(144,028)
Reclassification of (gain) loss on settled commodity derivatives, net of income taxes	34,948	31	(230,071)
OTHER COMPREHENSIVE INCOME (LOSS)	(38,801)	31	(230,071)
COMPREHENSIVE LOSS	$(11,043,839)	$(20,225,119)	$(33,280,174)

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	December 31, 2015	2014	2013
PERPETUAL PREFERRED STOCK - 9.25% CUMULATIVE AND REDEEMABLE, NO PAR VALUE:			
Balance at beginning of period: 507,739 shares for 2015 and 0 shares for 2014 and 2013	$9,958,217	$-	$-
Sales of 46,857 shares for 2015 and 507,739 shares for 2014	870,386	9,958,217	-
Balance at end of period: 554,596 shares for 2015, 507,739 shares for 2014, and 0 shares for 2013	10,828,603	9,958,217	-
COMMON STOCK, NO PAR VALUE:			
Balance at beginning of period: 69,139,869 shares for 2015, 41,074,950 shares for 2014, and 40,896,221 shares for 2013	137,469,772	2,669,465	2,182,833
Sales of 1,347,458 shares of common stock	1,363,160	-	-
Employee restricted stock awards (178,729 shares, vested 4/1/13, issued 9/11/14)	-	-	486,632
Restricted stock awards, of which 1,676,113 for 2015 and 19,440 for 2014 are vested	3,171,477	3,272,638	-
Buy back of 328,823 shares from vested stock awards	(300,732)	-	-
Stock appreciation rights issued, not vested	155,269	-	-
Restricted stock unit awards (273,907 shares)	-	869,231	-
Convert preferred stock to 22,883,487 shares of common stock on September 10, 2014	-	107,552,938	-
Pyramid Oil Company 4,788,085 shares outstanding last day of trading September 10, 2014	-	22,504,000	-
Fair value of Pyramid Oil Company stock options	-	100,500	-
Stock awards (100,000 shares) to employees, directors and consultants of Pyramid Oil Company vested upon the change in control and issued September 11, 2014	-	501,000	-
Balance at end of period: 71,834,617 shares for 2015, 69,139,869 shares for 2014, and 41,074,950 shares for 2013	141,858,946	137,469,772	2,669,465
ACCUMULATED OTHER COMPREHENSIVE INCOME:			
Balance at beginning of period	38,801	38,770	268,841
Comprehensive income (loss) from commodity derivative instruments, net of income taxes	(38,801)	31	(230,071)
Balance at end of period	-	38,801	38,770
ACCUMULATED EARNINGS (DEFICIT):			
Balance at beginning of period	(76,410,404)	(50,596,088)	(10,885,832)
Net loss attributable to Yuma Energy, Inc.	(11,005,038)	(20,225,150)	(33,050,103)

Series A perpetual preferred stock cash dividends	(1,047,191)	(224,098)	-
Preferred stock accretion (Series A and B)	-	(786,536)	(1,101,972)
Preferred stock cash dividends (Series A and B)	-	(445,152)	(145,900)
Preferred stock dividends paid in kind (Series A and B)	-	(4,133,380)	(5,412,281)
Balance at end of period	(88,462,633)	(76,410,404)	(50,596,088)
TOTAL EQUITY	$64,224,916	$71,056,386	$(47,887,853)

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Reconciliation of net loss to net cash provided by (used in) operating activities			
Net loss	$(11,005,038)	$(20,225,150)	$(33,050,103)
Goodwill write-off	5,349,988	-	-
Increase in fair value of preferred stock derivative liability	-	15,676,842	26,258,559
Depreciation, depletion and amortization of property and equipment	13,651,207	19,664,991	12,077,368
Accretion of asset retirement obligation	604,538	604,511	668,497
Stock-based compensation net of capitalized cost	2,289,311	3,388,321	452,058
Amortization of other assets and liabilities	286,010	188,669	166,608
Deferred tax expense (benefit)	(7,951,850)	(2,553,854)	3,080,272
Bad debt expense	839,171	97,068	193,601
Write off deferred offering costs	-	1,257,160	-
Write off credit financing costs	-	-	313,652
Amortization of benefit from commodity derivatives (sold) and purchased, net	-	(93,750)	(72,600)
Unrealized (gains) losses on commodity derivatives	949,967	(4,724,985)	231,886
Other	(342,835)	5,448	(21,328)
Changes in current operating assets and liabilities:			
Accounts receivable	6,877,906	976,093	(5,589,741)
Other current assets	77,711	(267,386)	869,550
Accounts payable	(13,688,145)	10,690,790	9,115,792
Other current liabilities	691,915	(218,468)	148,834
Other non-current liability	-	-	69,998
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	(1,370,144)	24,466,300	14,912,903
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on property and equipment	$(13,540,582)	$(25,526,887)	$(28,152,714)
Proceeds from sale of property	58,557	667,267	902,166
Cash received from merger	-	4,550,082	-
Decrease in short-term investments	1,170,868	2,125,541	-
Decrease (increase) in noncurrent receivable from affiliate	-	95,634	(2,493)
NET CASH USED IN INVESTING ACTIVITIES	(12,311,157)	(18,088,363)	(27,253,041)

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

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Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS – CONTINUED

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM FINANCING ACTIVITIES:			
Change in borrowing on line of credit	6,900,000	(8,315,000)	13,340,000
Proceeds from insurance note	813,562	901,257	872,754
Payments on insurance note	(832,770)	(796,441)	(878,328)
Line of credit financing costs	(250,141)	(92,909)	(681,739)
Net proceeds from sale of common stock	1,363,160	-	-
Net proceeds from sales of perpetual preferred stock	870,386	9,958,217	-
Deferred offering costs	(38,104)	-	(1,257,160)
Cash dividends to preferred stockholders	(1,047,191)	(669,250)	(145,900)
Common stock purchased from employees	(300,732)	-	-
NET CASH PROVIDED BY FINANCING ACTIVITIES	7,478,170	985,874	11,249,627
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(6,203,131)	7,363,811	(1,090,511)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	11,558,322	4,194,511	5,285,022
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$5,355,191	$11,558,322	$4,194,511
Supplemental disclosure of cash flow information:			
Interest payments (net of interest capitalized)	$131,521	$175,009	$22,210
Interest capitalized	$983,472	$1,059,350	$1,031,816
Supplemental disclosure of significant non-cash activity:			
Preferred dividends paid in kind (Series A and Series B)	$-	$4,133,380	$5,412,281
Change in capital expenditures financed by accounts payable	$3,382,555	$1,310,037	$1,904,581

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

Yuma Energy, Inc.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Yuma Energy, Inc., a California corporation ("YEI" and collectively with its subsidiaries, the "Company") (formerly Pyramid Oil Company ("Pyramid")), is an independent Houston-based exploration and production company focused on the acquisition, development and exploration for conventional and unconventional oil and natural gas resources, primarily in the U.S. Gulf Coast and California. YEI has employed a 3-D seismic-based strategy to build a multi-year inventory of development and exploration prospects. YEI's current operations are focused on onshore assets located in central and southern Louisiana, where the Company targets the Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex and Hackberry formations. In addition, the Company has a non-operated position in the Bakken Shale in North Dakota and operated positions in Kern and Santa Barbara Counties in California.

Basis of Presentation

The accompanying financial statements include the accounts of YEI on a consolidated basis. All significant intercompany accounts and transactions between YEI, YCI, Exploration, Petroleum, TSM and POL have been eliminated in the consolidation. All events described or referred to as prior to September 10, 2014 relate to Yuma Co. as the accounting acquirer. All references to "Pyramid" refer to the Company prior to the closing of the merger on September 10, 2014.

YEI and its subsidiaries maintain their accounts on the accrual method of accounting in accordance with the Generally Accepted Accounting Principles of the United States of America ("GAAP"). Each of YEI and its subsidiaries has a fiscal year ending December 31.

The financial statements were prepared on a going concern basis. The Company has been operating in a weak commodity price environment and was not in compliance with the trailing four quarter funded debt to EBITDA financial ratio covenant under its credit facility at September 30, 2015 and December 31, 2015 as well as the EBITDA to interest expense ratio at December 31, 2015. On December 30, 2015, the Company entered into a waiver with the lenders under its credit facility. On February 10, 2016, the Company entered into an Agreement and Plan of Merger and Reorganization with Davis Petroleum Acquisition Corp. ("Davis") for an all-stock transaction. See Note 24 – Subsequent Events.

Management's Use of Estimates

In preparing financial statements in conformity with GAAP, management is required to make informed estimates and assumptions with consideration given to materiality. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the reporting period. Actual results could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include: estimates of proved reserves and related estimates of the present value of future net revenues; the carrying value of oil and gas properties; estimates of fair value; asset retirement obligations; income taxes; derivative financial instruments; valuation allowances for deferred tax assets; uncollectible receivables; useful lives for depreciation; future cash flows associated with assets; obligations related to employee benefits; and legal and environmental risks and exposures.

Reclassifications

When required for comparability, reclassifications are made to the prior period financial statements to conform to the current year presentation.

Fair Value

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2 – inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – inputs that are not observable from objective sources, such as the Company's internally developed assumptions about market participant assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair value measurement.)

In determining fair value, the Company utilizes observable market data when available, or models that utilize observable market data. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value.

If the inputs used to measure the financial assets and liabilities fall within more than one level described above, the category is based on the lowest level input that is significant to the fair value measurement of the instrument (see Note 8 – Fair Value Measurements).

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable reported on the balance sheet approximates fair value.

The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt.

Nonfinancial assets and liabilities initially measured at fair value include certain assets acquired in a business combination, goodwill, asset retirement obligations and exit or disposal costs.

Level 3 Valuation Techniques – Financial assets are considered Level 3 when their fair values are determined using pricing models, discounted cash flow methodologies or similar techniques and at least one significant model assumption or input is unobservable. Level 3 financial liabilities consist of the Series A Preferred Stock issued on July 1, 2011, and the Series B Preferred Stock issued in July and August of 2012, for which there was no current market for these securities and such that the determination of fair value required significant judgment or estimation. The Company historically valued certain possible financial scenarios relating to its preferred and common stock securities prior to being publicly traded using a Monte Carlo simulation model with the assistance of an independent valuation consultant. Prior to being publicly traded, the Company's preferred stock securities had certain provisions, including automatic conditional conversion, re-pricing/down-round, change of control, default and follow-on offering that necessitated financial modeling. These models incorporated transaction details such as the stock price of comparable companies in the same industry, contractual terms, maturity, and risk free interest rates, as well as assumptions about future financings, volatility, and holder behavior (see Note 10 – Preferred Stock).

Cash Equivalents

Cash on hand, deposits in banks and short-term investments with original maturities of three months or less are considered cash and cash equivalents.

Short-term Investments

Short-term investments consisted of commercial bank certificates of deposit which matured in May 2015 and were valued at cost.

Trade Receivables

Accounts receivable are stated net of allowance for doubtful accounts of $532,719 and $138,960 at December 31, 2015 and 2014, respectively.

Management evaluates accounts receivable quarterly on an individual account basis, making individual assessments of collectability, and reserves those amounts it deems potentially uncollectible.

Inventories

Inventories, consisting principally of oilfield equipment, are carried at the lower of cost or market. The Company will often have tangible materials purchased for a well carried for the joint account (oil and gas property full cost pool on the balance sheet) pending sale or disposition.

Derivative Instruments

All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in the Company's Consolidated Balance Sheets as either an asset or liability and measured at fair value. Changes in the derivative instrument's fair value are recognized in earnings. Under cash flow hedge accounting, unrealized gains and losses were reflected in stockholders' equity as accumulated other comprehensive income ("AOCI") to the extent they were effective until the forecasted transaction occurred. Absent cash-flow accounting, all hedges are treated as non-qualifying derivative instruments and mark-to-market adjustments are in the Consolidated Statements of Operations. The Company discontinued cash flow hedge accounting effective January 1, 2013. The result of this change in policy was that the amount carried in AOCI at December 31, 2012 was amortized to oil and gas revenues during the month the hedges settled. Subsequent to December 31, 2012, all hedges are treated as non-qualifying derivative instruments and all new mark-to-market adjustments are in "Sales of natural gas and crude oil" in the Consolidated Statements of Operations. The final contracts that were included within AOCI expired at the end of 2015; therefore, the AOCI balance was zero at December 31, 2015.

Oil and Natural Gas Properties

Investments in oil and natural gas properties are accounted for using the full cost method of accounting. Under this method, all costs directly related to the acquisition, exploration, exploitation and development of oil and natural gas properties are capitalized.

Costs of reconditioning, repairing, or reworking producing properties are expensed as incurred. Costs of workovers adding proved reserves are capitalized. Projects to deepen existing wells, recomplete to a shallower horizon, or improve (not restore) production to proved reserves are capitalized.

Sales of proved and unproved properties 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. Abandonments of properties are accounted for as adjustments of capitalized costs with no loss recognized.

Depreciation, Depletion and Amortization – The capitalized cost of oil and natural gas properties, excluding unevaluated properties, is amortized using the unit-of-production method (equivalent physical units of 6 Mcf of natural gas to each barrel of oil equivalent, or "Boe") using estimates of proved reserve quantities. Investments in unproved properties are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of the assessment indicate that the properties are impaired, the amount of impairment is added to the proved oil and gas property costs to be amortized. The amortizable base includes future development, abandonment and restoration costs. The rate for depreciation, depletion and amortization ("DD&A" or "depletion") per Boe for the Company was $20.45, $24.92 and $23.87 for fiscal years 2015, 2014 and 2013, respectively. DD&A expense for oil and natural gas properties was $13,375,452, $19,490,653 and $11,927,872 for fiscal years 2015, 2014 and 2013, respectively.

Impairments – Total capitalized costs of oil and gas properties are subject to a limit, or so-called "ceiling test." The ceiling test limits total capitalized costs less related accumulated DD&A and deferred income taxes to a value not to exceed the sum of (i) the present value, discounted at a ten percent annual interest rate, of future net revenue from estimated production of proved oil and gas reserves, including the impact of cash flow hedges, based on current economic and operating conditions less future development costs (excluding retirement costs); plus (ii) the cost of properties not subject to amortization; less (iii) income tax effects related to differences in the book and tax basis of oil and gas properties. If unamortized capitalized costs less related deferred income taxes exceed this limit, the excess is charged to DD&A in the quarter the assessment is made. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. These net unamortized costs, tested each calendar quarter, have not exceeded the cost center ceiling for fiscal years 2015, 2014 and 2013.

Oil and natural gas properties not subject to amortization consist of undeveloped leaseholds and exploratory and developmental wells in progress before the assignment of proved reserves. Management reviews the costs of these properties periodically for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in impairment assessments include drilling results by the Company and other operators, the terms of oil and gas leases not held for production, and available funds for exploration and development.

The table below shows the cost of unproved properties, along with well and development costs in progress not subject to amortization at December 31, 2015, and the year in which those costs were incurred.

	Year of acquisition				
	2015	2014	2013	Prior	Total
Leasehold acquisition cost	$(9,039,268)	$154,194	$1,704,190	$19,247,036	$12,066,152
Exploration and development cost	(1,739,341)	891,610	1,059,262	172,159	383,690
Capitalized interest	(639,726)	609,970	829,456	1,027,969	1,827,669
Total	$(11,418,335)	$1,655,774	$3,592,908	$20,447,164	$14,277,511

Capitalized Interest – Capitalized interest is included as part of the cost of oil and natural gas properties. The Company capitalized $983,472, $1,059,350 and $1,031,816 of interest associated with the line of credit (see Note 13 – Debt and Interest Expense) during fiscal years 2015, 2014 and 2013, respectively. The capitalization rates are based on the Company's weighted average cost of borrowings used to finance prospect generation.

Capitalized Internal Costs – Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by the Company for its own account, and that are not related to production, general corporate overhead or similar activities, are also capitalized. The Company capitalized $3,090,013, $3,442,095 and $2,702,952 of allocated indirect costs, excluding interest, related to these activities during fiscal years 2015, 2014 and 2013, respectively.

The Company develops oil and natural gas drilling projects called "prospects" by industry participants and markets participation in these projects. In doing this, the Company typically earns a profit over its actual costs in seismic, land, brokerage, brochuring and marketing. It typically markets interests in the project on a "third for a quarter" basis, whereby the participant pays a percentage of the cost to casing point or through prospect payout and then has its participation interest reduced by twenty-five percent (25%) with the Company earning the difference. This difference is referred to as the "carried interest."

The Company assembles 3-D seismic survey projects and markets participating interests in the projects. The Company typically recovers all of its costs plus allocated overhead, and receives a quarterly general and administrative ("G&A") expense reimbursement paid by the various participants in the project during the 3-D seismic acquisition phase and the 3-D seismic interpretation phase. The proceeds from the sale of the 3-D seismic survey along with the quarterly G&A reimbursements are included in the full cost pool caption "Not subject to amortization." In addition, the participants in the 3-D seismic survey typically carry the Company for a percentage of the costs associated with the 3-D survey acquisition, ranging from 25 to 35 percent. The Company received G&A expense reimbursements of $-0-, $-0- and $42,329 in fiscal years 2015, 2014 and 2013, respectively.

Other Property and Equipment

Other property and equipment is generally recorded at cost, with the exception of the Pyramid property that was acquired in the merger, which was marked to fair value as of the closing date of the merger. Expenditures for major additions and improvements are capitalized, while maintenance, repairs and minor replacements which do not improve or extend the life of such assets are charged to operations as incurred. Property and equipment sold, retired or otherwise disposed of are removed at cost less accumulated depreciation, and any resulting gain or loss is reflected in "Other" in "Total Expenses" in the accompanying Consolidated Statements of Operations.

Office business machines and furniture and fixtures are depreciated using the modified accelerated cost recovery system ("MACRS") for financial reporting purposes. MACRS depreciation methods approximate depreciation expense computed under GAAP using the double declining balance method.

Depreciation of drilling and operating equipment, automotive, and buildings is computed using the straight-line method over the shorter of the estimated useful lives or the applicable lease terms.

Leasehold improvements for the corporate office space in Houston, Texas are depreciated by the straight line method over the term of the lease.

	Estimated useful life in years	December 31, 2015	December 31, 2014
Land	n/a	$2,469,000	$2,469,000
Office business machines	3 - 5	1,381,968	1,361,149
Drilling and operating equipment	14	982,010	982,010
Furniture and fixtures	7	412,215	412,215
Automotive	5	351,707	351,707
Office leasehold improvements	5	332,607	332,607
Buildings and improvements	3 - 25	326,000	326,000
Total other property and equipment		6,255,507	6,234,688
Less: Accumulated depreciation and leasehold improvement amortization		(2,174,316)	(1,909,352)
Net book value		$4,081,191	$4,325,336

Depreciation and leasehold improvement amortization expense totaled $275,756, $174,338 and $149,496 for the years ended December 31, 2015, 2014 and 2013, respectively.

Goodwill

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. The provisions of Accounting Standards Codification (“ASC”) 350, Intangibles – Goodwill and Other (“ASC 350”) require that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment, or more frequently if events occur 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. However, the Company has only one reporting unit. To assess impairment, the Company has the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the book value. Absent a qualitative assessment, or, through the qualitative assessment, if the Company determines it is more likely than not that the fair value of the reporting unit is less than the book value, a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the book value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. The Company’s goodwill as of December 31, 2014 related to its acquisition of Pyramid. The drop in crude oil prices and the resulting decline in the Company’s common share price caused the Company to test goodwill for impairment at June 30, 2015. Goodwill was determined to be fully impaired and as a result, the balance of $5,349,988 was written off. Refer to Note 14 – Merger with Pyramid Oil Company and Goodwill for more details.

Accounts Payable

Accounts payable consist principally of trade payables and costs associated with oil and natural gas exploration.

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources, along with liabilities for environmental remediation or restoration claims, are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Expenditures related to environmental matters are expensed or capitalized in accordance with the Company's accounting policy for property and equipment.

Revenue Recognition

Revenue is recognized by the Company when deliveries of crude oil, natural gas and condensate are delivered to the purchaser and title has transferred. Crude oil sales in Louisiana, representing a significant portion of the Company's production, are typically indexed to Light Louisiana Sweet ("LLS"). TSM recognizes revenue from sales of natural gas primarily to other marketing companies and industrials in the period in which the natural gas is delivered and billed to the customer. Sales are based on index prices per MMBtu or the daily "spot" price as published in national publications with a mark-up or mark-down defined by contract with each customer.

Income Taxes

The Company files a consolidated federal tax return. Deferred taxes have been provided for temporary timing differences. These differences create taxable or tax-deductible amounts for future periods (see Note 16 – Income Taxes).

Other Taxes

Taxes incurred, other than income taxes, are as follows:

		December 31,	
	2015	2014	2013
Production and severance tax	$1,678,825	$2,693,396	$2,403,263
Ad valorem tax	1,103,913	1,046,134	732,302
Sales tax	18,534	62,864	180,498
State franchise taxes	68,248	40,740	41,072
Total	$2,869,520	$3,843,134	$3,357,135

The Company reports oil and natural gas sales on a gross basis and, accordingly, includes net production, severance, and ad valorem taxes on the accompanying Consolidated Statements of Operations as a component of lease operating expenses. Sales taxes are collected from customers on sales of natural gas by TSM, and remitted to the appropriate state agency. Exploration accrues sales tax on applicable purchases of materials, and remits funds directly to the taxing jurisdictions.

Financial Instruments

The Company's financial instruments consist of cash, receivables, payables, long-term debt, oil and natural gas derivatives, and (prior to the merger as described in Note 14 – Merger with Pyramid Oil Company and Goodwill) Series A and Series B Preferred Stock. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of these items.

Accumulated Other Comprehensive Income

AOCI includes changes in equity that are excluded from the Consolidated Statements of Operations and recorded directly into a separate section of equity on the Consolidated Balance Sheets. The Company's AOCI shown on the Consolidated Balance Sheets and the Consolidated Statements of Changes in Equity consists of unrealized income and losses on cash flow hedges; however, the Company discontinued hedge accounting effective January 1, 2013. The final contracts that were included within AOCI expired at the end of 2015; therefore, the AOCI balance was zero at December 31, 2015.

General and Administrative Expenses – Stock-Based Compensation

This includes payments to employees in the form of restricted stock awards, restricted stock units, stock appreciation rights and stock options. As such, these amounts are non-cash Company stock-based awards.

The Company adopted the 2011 Stock Option Plan on June 21, 2011, and the 2014 Long-Term Incentive Plan effective September 10, 2014 (see Note 15 – Stockholders' Equity). The Company adopted an Annual Incentive Plan for fiscal years 2015, 2014 and 2013 (see Note 18 – Employee Benefit Plans).

The Company accounts for stock-based compensation at fair value. The Company grants equity-classified awards including stock options and vested and non-vested equity shares (restricted stock awards and units).

The fair value of stock option awards and stock appreciation rights is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of common stock.

The Company records compensation cost, net of estimated forfeitures, for non-vested stock units over the requisite service period using the straight-line method. An adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the awards. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See Note 11 – Stock-Based Compensation.

General and Administrative Expenses - Other

G&A expenses are reported net of amounts capitalized pursuant to the full cost method of accounting.

Re-engineering and Workovers

One of the Company's core business strategies is to perform a comprehensive field re-engineering and design to increase and maintain production, lower per-unit operating expenses, and improve field economics. Re-engineering projects are undertaken with the intent of lowering per-unit operating expenses and/or reducing field down-time. In addition, the Company seeks to implement more efficient production practices in order to increase production and/or arrest natural field production declines. These practices are often deployed in fields in connection with or in anticipation of further field development activities such as installation of secondary recovery operations or additional drilling. Workovers included within this category relate to significant non-recurring operations.

Other Noncurrent Assets

Noncurrent assets at December 31, 2015 are comprised of deferred costs related to future potential equity raises. If these potential equity raises come to fruition, then costs are netted from the new equity issuance; if not, then those costs are charged to G&A. In 2014, noncurrent assets were comprised of debt financing costs, which were moved to current in 2015.

Earnings per Share

The Company's basic earnings per share ("EPS") is computed based on the average number of shares of common stock outstanding for the period. Diluted EPS includes the effect of the Company's outstanding stock awards, if the inclusion of these items is dilutive. See Note 15 – Stockholders' Equity.

Changes in Accounting Principles

Not Yet Adopted

In May 2014 and August 2015, the Financial Accounting Standards Board ("FASB") issued an update that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. Among other things, the standard requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for the Company in the first quarter of 2018 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is permitted. The Company is evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In July 2015, the FASB issued an update that requires an entity to measure inventory at the lower of cost and net realizable value. This excludes inventory measured using LIFO or the retail inventory method. This standard is effective for the Company in the first quarter of 2017 and will be applied prospectively. Early adoption is permitted. The Company does not expect the adoption of this standard to have a significant impact on its consolidated results of operations, financial position or cash flows.

In May 2015, the FASB issued an update that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The amendment also removes certain disclosure requirements regarding all investments that are eligible to be measured using the net asset value per share practical expedient and only requires certain disclosures on those investments for which an entity elects to use the net asset value per share expedient. This standard is effective for the Company in the first quarter of 2016 and will be applied on a retrospective basis. Early adoption is permitted. This standard only modifies disclosure requirements; as such, there will be no impact on the Company's consolidated results of operations, financial position or cash flows.

In April 2015, the FASB issued an update that requires debt issuance costs to be presented in the balance sheet as a direct reduction from the associated debt liability. This standard is effective for the Company in the first quarter of 2016 and early adoption is permitted. The Company is evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In February 2015, the FASB issued an amendment to the guidance for determining whether an entity is a variable interest entity (“VIE”). The standard does not add or remove any of the five characteristics that determine if an entity is a VIE. However, it does change the manner in which a reporting entity assesses one of the characteristics. In particular, when decision-making over the entity’s most significant activities has been outsourced, the standard changes how a reporting entity assesses if the equity holders at risk lack decision making rights. This standard is effective for the Company for annual periods beginning after December 15, 2015 and early adoption is permitted, including in interim periods. The Company does not expect the adoption of this standard to have a significant impact on its consolidated results of operations, financial position or cash flows.

Recently adopted

In November 2015, the FASB issued an update that requires an entity to classify deferred income tax liabilities and assets as noncurrent in a classified statement of financial position. The amendments are effective for the Company in the first quarter of 2017 and early adoption is permitted. The Company elected to early adopt these amendments in the fourth quarter of 2015 on a prospective basis. Adoption of this standard did not have a significant impact on the Company’s consolidated results of operations, financial position or cash flows.

In August 2014, the FASB issued an update that requires management to assess an entity’s ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards. This standard is effective for the Company in the first quarter of 2017 and early adoption is permitted. The Company elected to early adopt and has provided disclosures in conformity with this new standard.

In April 2014, the FASB issued an amendment to accounting standards that changes the criteria for reporting discontinued operations while enhancing related disclosures. Under the amendment, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization’s operations and financial results. Expanded disclosures about the assets, liabilities, income and expenses of discontinued operations are required. In addition, disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting will be made in order to provide users with information about the ongoing trends in an organization’s results from continuing operations. The amendments were effective for the Company in the first quarter of 2015. Adoption of this standard did not have a significant impact on the Company’s consolidated results of operations, financial position or cash flows.

NOTE 2 – ORGANIZATION AND CONSOLIDATION

On September 10, 2014, a wholly owned subsidiary of the Company merged with and into Yuma Energy, Inc., a Delaware corporation (“Yuma Co.”), in exchange for 66,336,701 shares of the Company’s common stock, and the Company subsequently changed its name from “Pyramid Oil Company” to “Yuma Energy, Inc.” which the Company refers to as the “merger”. As a result of the merger, the former Yuma Co. stockholders held approximately 93%, of the then-outstanding common stock of the Company, and thus acquired voting control. Although Pyramid was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of Pyramid by Yuma Co. See Note 14 – Merger with Pyramid Oil Company and Goodwill for additional information.

Simultaneously with the closing of the merger, Yuma Co. changed its name to "The Yuma Companies, Inc." In addition, a subsidiary of the Company, Pyramid Oil LLC, a California limited liability company, was formed to hold Pyramid's oil and natural gas properties.

The Consolidation

YEI was incorporated on October 9, 1909 and has six subsidiaries as listed below. Their financial statements are consolidated with those of YEI.

Company name	Reference	State of incorporation	Date of incorporation
The Yuma Companies, Inc.	"YCI"	Delaware	10/30/96
Yuma Exploration and Production Company, Inc.	"Exploration"	Delaware	01/16/92
Yuma Petroleum Company	"Petroleum"	Delaware	12/19/91
Texas Southeastern Gas Marketing Company	"TSM"	Texas	09/12/96
Pyramid Oil LLC	"POL"	California	08/08/14
Pyramid Delaware Merger Subsidiary, Inc.	"PDMS"	Delaware	02/04/14

YCI and PDMS are wholly owned subsidiaries of YEI, and YCI is the parent corporation of Exploration, Petroleum and TSM. Exploration is the parent corporation of POL.

Exploration identifies and captures economic deposits of hydrocarbons by using: (i) 3-D seismic imaging and other advanced technologies, with an emphasis on acquiring proprietary 3-D seismic to systematically explore, exploit and develop onshore and offshore crude oil and natural gas provinces; (ii) unconventional oil resource plays; and (iii) high impact deep structural prospects located beneath known producing trends. Historically, Exploration has sold working interests in prospects to industry partners on traditional terms. Exploration's operations are primarily conducted in the Gulf Coast region.

Petroleum became relatively inactive during 1998 due to the transfer of substantially all exploration and production activities to Exploration.

TSM is primarily engaged in the marketing of natural gas in Louisiana. TSM has elected to discontinue operations in 2016 (see Note 24 – Subsequent Events).

POL is primarily engaged in holding assets located in the State of California.

PDMS was inactive during 2015.

NOTE 3 – LIQUIDITY CONSIDERATIONS AND GOING CONCERN

The Company has borrowings which require, among other things, compliance with certain financial ratios. Due to operating losses the Company has sustained during recent quarters as a result of the prolonged weak commodity price environment and other factors, the Company was not in compliance with the trailing four quarter funded debt to EBITDA financial ratio covenant under its credit facility at September 30, 2015 and at December 31, 2015 as well as its EBITDA to interest expense ratio as of December 31, 2015. On December 30, 2015, the Company entered into the Waiver, Borrowing Base Redetermination and Ninth Amendment to the credit agreement which provided for a $29.8 million conforming borrowing base, which will be automatically reduced to $20.0 million on May 31, 2016 unless otherwise reduced by or adjusted to a different number by the lenders under the credit agreement, and waived the compliance with the trailing four quarter funded debt to EBITDA and EBITDA to interest expense financial ratio covenants or any other events of default under the credit facility for the quarters ended September 30, 2015 and December 31, 2015. As of December 31, 2015, the Company had a working capital deficit of $27.2 million inclusive of the Company's outstanding debt under its credit facility, which was fully drawn with no additional borrowing capacity available.

A breach of any of the terms and conditions of the credit agreement or a breach of the financial covenants under the Company's credit facility could result in acceleration of the Company's indebtedness, in which case the debt would become immediately due and payable. Given that the Company anticipates being in violation of the funded debt to EBITDA and EBITDA to interest expense covenants as of March 31, 2016, the Company has classified its bank debt as a current liability in its financial statements.

During 2015, the Company initiated several strategic alternatives to remedy its debt covenant compliance issues and provide working capital to develop the Company's existing assets. On February 10, 2016, the Company entered into an Agreement and Plan of Merger and Reorganization with Davis Petroleum Acquisition Corp. ("Davis") for an all-stock transaction. Upon completion of the transaction, which is subject to the approval of the stockholders of both companies, Davis will become a wholly owned subsidiary of Yuma. Subject to bank approval, it is anticipated that the Company will enter into another credit agreement amendment that will take into account the contemplated merger with Davis (see Note 24 – Subsequent Events). However, the Company's management can provide no assurance that the merger with Davis and the amendment to the credit agreement will actually occur.

The significant risks and uncertainties described above raise substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

NOTE 4 – ADDISON ACQUISITION

On April 5, 2013, the Company acquired from Addison Oil, L.L.C. ("Addison") approximately 51,460 net acres held by production in the Austin Chalk adjacent to 25,926 net acres held by the Company at that time. This acquisition increased the Company's acreage holdings in the Austin Chalk to over 77,000 net acres at the time of closing. The purchase price was $7.5 million, with an effective date of January 1, 2013. The Company granted a two percent overriding royalty to the sellers, and sellers have a right to participate in new wells or new side tracks for a twenty-five percent (25%) working interest. This acquisition complemented the Company's existing acreage position and substantially increased the Company's number of proved undeveloped drilling locations and proved reserve values.

Associated with this acquisition, the Company recorded $6,043,412 for the associated future asset retirement obligations and $1,440,702 in suspended royalty and revenue obligations, net of related receivables at the time of the merger.

NOTE 5 – ASSET RETIREMENT OBLIGATIONS

The Company records the cost of obligations associated with the retirement of tangible long-lived assets at fair value when the asset is acquired. The asset retirement obligations ("ARO's") are recorded as liabilities and the associated costs are capitalized as part of the related long-lived assets and then depreciated over the remaining useful lives. Changes in the liabilities resulting from the passage of time are recognized as operating (accretion) expenses and are allocated using the interest method. For the Company, ARO's relate to the abandonment of oil and gas producing facilities.

Since the Company uses the full cost method, settlement recognition is impacted. If a liability is settled for an amount other than the recorded amount, an adjustment is made to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. In addition, the Company carries ARO assets on the balance sheet as part of its full cost pool, and includes these ARO assets in its amortization base for the purposes of calculating depreciation, depletion and amortization expense.

The net decrease of $3,697,272 to ARO during 2015 is due primarily to revised estimates of P&A cost for Masters Creek and Main Pass properties. P&A cost were revised to reflect current market conditions and efficiencies gained by developing P&A programs for multiple wells.

Asset Retirement Obligations

	December 31, 2015	December 31, 2014
Beginning of year balance	$12,487,770	$10,697,679
Pyramid liabilities assumed in the merger	-	943,951
Liabilities incurred during year	24,588	416,162
Liabilities settled during year	(35,455)	-
Accretion expense	604,538	604,511
Revisions in estimated cash flows	(4,290,943)	(174,533)
End of year balance	$8,790,498	$12,487,770

NOTE 6 – RECEIVABLES AND PAYABLES WITH AFFILIATES, CHIEF EXECUTIVE OFFICER AND EMPLOYEES

The following table provides information with respect to related party transactions with affiliates, the Chief Executive Officer ("CEO") of the Company, and employees. The trade receivable from the CEO is primarily for invoiced costs on prospects and wells as part of his normal joint interest billings (see Note 7 – Related Party Transactions).

	December 31, 2015	December 31, 2014
Receivables from affiliates, CEO and employees:		
Current:		
Yuma CEO	$63,329	$174,720
Employees	12,075	141,357
Total	$75,404	$316,077

NOTE 7 – RELATED PARTY TRANSACTIONS

Chief Executive Officer

Effective August 15, 2011, the Company entered into a Working Interest Incentive Plan ("WIIP") with the Company's CEO, Sam L. Banks. Under the WIIP, Mr. Banks could purchase:

- Working interests in prospects from the Company or from unaffiliated third parties up to 2.5% of the Company's working interest; and

- Working interests in production acquisitions that the Company undertakes in an amount up to 2.5% (previously 5%) of the aggregate cost of the interest to be acquired.

The purchase price for any working interests acquired from the Company under the plan was no better than the terms agreed to by unaffiliated third parties.

The Board of Directors terminated the WIIP effective September 21, 2015.

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Working interests acquired during fiscal years 2014 and 2013 under the WIIP are listed below (no working interests were acquired under the WIIP during fiscal year 2015):

Year	Well, prospect or project	Working interest		Amount paid
2014	Anaconda Prospect (Talbot 23-1)	1.95000	%	$ 16,900
2014	Gardner Island Well &	1.43600	%	
	Main Pass 4 Facility	1.85500	%	$ 78,988
2014	Austin Chalk (Additional W.I.)	1.00000	%	$ 16,000
2013	Bell City East Prospect	.71063	%	$ 5,330
2013	Austin Chalk	1.00000	%	$ 9,412
2013	Addison Acquisition	2.00000	%	$ 150,000

In 2006, the Company entered into participation agreements with several unrelated industry participants under which it would receive a 20% back-in interest after payout to the participants and the CEO would receive a 5% back-in interest. The agreements were renegotiated in 2010 reducing the total back-in interest by 40% with the Company receiving 12.5% and the CEO receiving 2.5%. The project, named La Posada, achieved multiple discrete payouts during 2013 based on differing participant cost basis and the participants assigned the agreed working interests directly to each of the Company and the CEO at time of payout.

NOTE 8 – FAIR VALUE MEASUREMENTS

Certain financial instruments are reported at fair value on the Consolidated Balance Sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels (see the Fair Value section of Note 1 – Summary of Significant Accounting Policies). The Company uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

Fair Value of Financial Instruments (other than Commodity Derivative, see below) – The carrying values of financial instruments, excluding commodity derivatives, comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments.

Derivatives – The fair values of the Company's commodity derivatives are considered Level 2 as their fair values are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by the Company's counterparties for reasonableness. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which results in the Company using market prices and implied volatility factors related to changes in the forward curves. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. Because the Company's commodity derivative counterparty was Société Générale ("SocGen") at December 31, 2015 (see Note 9 – Commodity Derivative Instruments), the Company has not considered non-performance risk in the valuation of its derivatives.

	Fair value measurements at December 31, 2015			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
Assets:				
Commodity derivatives – oil	$-	$3,442,693	$ -	$3,442,693
Commodity derivatives – gas	-	285,895	-	285,895
Total assets	$-	$3,728,588	$ -	$3,728,588

	Fair value measurements at December 31, 2014			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
Assets:				
Commodity derivatives – oil	$-	$2,858,387	$ -	$2,858,387
Commodity derivatives – gas	-	1,883,259	-	1,883,259
Total assets	$-	$4,741,646	$ -	$4,741,646

Derivative instruments listed above include swaps, reverse swaps, three-way collars and put spreads. For additional information on the Company's derivative instruments and derivative liabilities, see Note 9 – Commodity Derivative Instruments.

On September 10, 2014, the value of the Series A and Series B Preferred Stock and associated derivative was marked to market. The preferred stock was converted to common stock as further described in Note 14 – Merger with Pyramid Oil Company and Goodwill. With the conversion of the shares of Series A and Series B Preferred Stock to common stock, the value of the associated derivative liability was marked to market, then transferred to common stock equity.

Debt – The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheets. For further discussion of the Company's debt, see Note 13 – Debt and Interest Expense. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

Asset Retirement Obligations – The Company estimates the fair value of ARO's based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, amounts and timing of settlements, the credit-adjusted risk-free rate to be used and inflation rates. See Note 5 – Asset Retirement Obligations for a summary of changes in ARO's.

NOTE 9 – COMMODITY DERIVATIVE INSTRUMENTS

Objective and Strategies for Using Commodity Derivative Instruments – In order to mitigate the effect of commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of the Company's crude oil and natural gas, the Company enters into crude oil and natural gas price commodity derivative instruments with respect to a portion of the Company's expected production. The commodity derivative instruments used include futures, swaps, and options to manage exposure to commodity price risk inherent in the Company's oil and natural gas operations.

Futures contracts and commodity price swap agreements are used to fix the price of expected future oil and natural gas sales at major industry trading locations such as Henry Hub, Louisiana for natural gas and Cushing, Oklahoma for oil. Basis swaps are used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and ceiling price (collar) for expected future oil and natural gas sales.

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

While these instruments mitigate the cash flow risk of future reductions in commodity prices, they may also curtail benefits from future increases in commodity prices.

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting resided in AOCI and were reclassified to earnings as the transactions to which the derivatives related were recognized in earnings. The remaining contracts that were subject to hedge accounting expired during 2015 and AOCI is now zero.

The Company elected to discontinue hedge accounting for all commodity derivative instruments beginning with the 2013 financial year. The balance in other comprehensive income (“OCI”) at year-end 2012 remained in AOCI until the original hedged forecasted transactions occurred. The last of these contracts expired in December 2015. No mark-to-market adjustments for commodity derivative contracts are made to AOCI, but instead are recognized in earnings. As a result of discontinuing the application of hedge accounting, the Company’s earnings are potentially more volatile. See Note 8 – Fair Value Measurements for a discussion of methods and assumptions used to estimate the fair values of the Company’s commodity derivative instruments.

Counterparty Credit Risk – Commodity derivative instruments expose the Company to counterparty credit risk. The Company’s commodity derivative instruments are with SocGen which is rated “A” by Standard and Poor’s, “A2” by Moody’s, “A” by Fitch and “A (high)” by DBRS. Commodity derivative contracts are executed under master agreements which allow the Company, in the event of default, to elect early termination of all contracts. If the Company chooses to elect early termination, all asset and liability positions would be netted and settled at the time of election.

On February 18, 2015, the Company settled all of its natural gas and crude oil options, realizing $4.03 million. The Company retained its existing natural gas swap positions. Concurrent with the settlement of the Company’s option positions and during the following day, the Company entered into new swap transactions for crude oil and natural gas for the balance of 2015 and all of 2016. In addition, the Company entered into three-way collars for 2017 for both natural gas and crude oil.

In conjunction with certain derivative hedging activity, the Company deferred the payment of $153,389 put premiums which was recorded in both current other deferred charges and current other accrued liabilities at year-end 2014 and was for production months January 2015 through December 2015. The put premium liabilities became payable monthly as the hedge production month became the prompt production month. The Company amortized the deferred put premium liabilities in January and February 2015; however, the liability for the remainder of the year was settled as part of the $4.03 million settlement.

Commodity derivative instruments open as of December 31, 2015 are provided below. Natural gas prices are New York Mercantile Exchange ("NYMEX") Henry Hub prices, and crude oil prices are NYMEX West Texas Intermediate ("WTI"), except for the oil swaps noted below that are based on Argus Light Louisiana Sweet ("LLS").

	2016 Settlement	2017 Settlement
NATURAL GAS (MMBtu):		
Swaps		
Volume	298,957	-
Price (NYMEX)	$3.28	-
3-way collars		
Volume	-	67,361
Ceiling sold price (call) (NYMEX)	-	$4.03
Floor purchased price (put) (NYMEX)	-	$3.50
Floor sold price (short put) (NYMEX)	-	$3.00
CRUDE OIL (Bbls):		
Put spread		
Volume	138,286	-
Floor purchased price (put) (LLS)	$62.27	-
Floor sold price (short put) (LLS)	$40.00	-
3-way collars		
Volume	-	113,029
Ceiling sold price (call) (WTI)	-	$77.00
Floor purchased price (put) (WTI)	-	$60.00
Floor sold price (short put) (WTI)	-	$45.00

Derivatives for each commodity are netted on the Consolidated Balance Sheets as they are all contracts with the same counterparty. The following table presents the fair value and balance sheet location of each classification of commodity derivative contracts on a gross basis without regard to same-counterparty netting:

	Fair value as of December 31,	
	2015	2014
Asset commodity derivatives:		
Current assets	$3,069,115	$6,413,935
Noncurrent assets	1,841,120	3,163,891
	4,910,235	9,577,826
Liability commodity derivatives:		
Current liabilities	(411,068)	(3,075,398)
Noncurrent liabilities	(770,579)	(1,760,782)
	(1,181,647)	(4,836,180)
Total commodity derivative instruments	$3,728,588	$4,741,646

Sales of natural gas and crude oil on the Consolidated Statements of Operations are comprised of the following:

	Years Ended December 31,		
	2015	2014	2013
Sales of natural gas and crude oil	$18,680,584	$38,659,392	$28,235,413
Gains (losses) realized from sale of commodity derivatives	4,030,000	-	-
Other gains (losses) realized on commodity derivatives	1,958,793	(1,420,217)	(524)
Unrealized gains (losses) on commodity derivatives	(949,967)	4,724,985	(231,886)
Amortized gains from benefit of sold qualified gas options	-	93,750	72,600
Total revenue from natural gas and crude oil	$23,719,410	$42,057,910	$28,075,603

A reconciliation of the components of accumulated other comprehensive income (loss) in the Consolidated Statements of Changes in Equity is presented below:

	Years Ended December 31,					
	2015		2014		2013	
	Before tax	After tax	Before tax	After tax	Before tax	After tax
Balance, beginning of period	$63,091	$38,801	$63,041	$38,770	$437,140	$268,841
Sale of unexpired contracts previously subject to hedge accounting rules	(119,917)	(73,749)	-	-	-	-
Other reclassifications due to expired contracts previously subject to hedge accounting rules	56,826	34,948	50	31	(374,099)	(230,071)
Balance, end of period	$-	$-	$63,091	$38,801	$63,041	$38,770

NOTE 10 – PREFERRED STOCK

9.25% Series A Cumulative Redeemable Preferred Stock - On October 23, 2014, the Company held an initial closing of its public offering of 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”). The Company issued 477,273 shares at a public offering price of $22.00 per share, for gross proceeds of $10,500,006. On October 24, 2014, the Company held an additional closing for 30,466 shares of Series A Preferred Stock at a public offering price of $22.00 per share for gross proceeds of $670,252. In total, the Company received $10,430,894 net of the underwriters’ discount and underwriters’ expenses. Proceeds net of all expenses were $9,983,335. Preferred stock is also net of $25,118 in costs through December 31, 2014 to initiate an At Market Issuance Sales Agreement (“Sales Agreement”) (see Note 23 – At Market Security Sales). The $870,386 increase to preferred stock during 2015 represents the net proceeds from the sale of 46,857 shares (37,769 shares sold under the Sales Agreement during the quarter ended March 31, 2015 and 9,088 shares sold during the quarter ended June 30, 2015). The shares of Series A Preferred Stock trade on the NYSE MKT under the symbol “YUMAprA”. The Series A Preferred Stock cannot be converted into common stock (except upon a change in control and in the event the Company chooses to not redeem the Series A Preferred Stock), but may be redeemed by the Company, at the Company’s option, on or after October 23, 2017 (or in certain circumstances, prior to such date as a result of a change in control of the Company), at a redemption price of $25.00 per share plus any accrued and unpaid dividends. The Series A Preferred Stock has no stated maturity, is not subject to any sinking fund or mandatory redemption, and will remain outstanding indefinitely unless repurchased, redeemed or converted into common stock in connection with a change in control. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the Board of Directors, cumulative dividends at the rate of 9.25% per annum (the dividend rate) based on the liquidation price of $25.00 per share of the Series A Preferred Stock, payable monthly in arrears on each dividend payment date, with the first payment date of December 1, 2014. The Series A Preferred Stock is presented in the permanent equity section of the financial statements.

Dividends on the Series A Preferred Stock are declared monthly based on the assessment of the Company's financial position by the Board of Directors. Due to the current depressed commodity price environment as well as other factors which have adversely affected the Company's cash flows and liquidity, the monthly dividends on the Series A Preferred Stock were suspended beginning with the month ended November 30, 2015 until such time as the Company and the Board of Directors have deemed that the Company has sufficient liquidity to restore their payment.

Pursuant to the merger agreement with Davis, the Company has agreed as part of the reincorporation from California to Delaware, subject to approval of the holders of Series A Preferred Stock, to convert each share of the Company's existing Series A Preferred Stock into 35 shares of common stock prior to giving effect for the reverse split (3.5 shares post reverse split). See Note 24 – Subsequent Events for a discussion of the merger agreement with Davis.

Series A and Series B Preferred Stock of Yuma Co. – Prior to the closing of the merger on September 10, 2014, Yuma Co. had two classes of preferred stock outstanding, the Series A and Series B. Immediately prior to the closing of the merger, these shares of preferred stock were converted to common stock of Yuma Co. At the closing of the merger, the common stock of Yuma Co. was converted into common stock of the Company.

The Series A and Series B Preferred Stock is presented on the Company's balance sheet between Other Noncurrent Liabilities and Equity (the mezzanine section) since it has characteristics of both debt and equity. The carrying amount on the Company's balance sheets represents the net proceeds increased by accretion of stock issue costs less the value at time of origination of the embedded conversion feature. The accretion of issue costs increased the Preferred Stock by amortizing the costs to equity through the trigger date for the Company's repurchase of such shares.

On June 30, 2013, December 31, 2013, and June 30, 2014, Yuma Co. elected to pay the semi-annual dividends to the preferred stockholders in additional shares of preferred stock (in kind), with cash payments being made in lieu of any fractional shares. The following shares and cash payments were issued to the existing preferred stockholders as of the record dates:

	June 30, 2013		December 31, 2013		June 30, 2014	
	Additional preferred shares	Cash payments	Additional preferred shares	Cash payments	Additional preferred shares	Cash payments
Series A Preferred Stock	403	$35,150	630	$45,360	893	$45,280
Series B Preferred Stock	533	$24,700	533	$40,690	536	$53,680

On September 15, 2014, the Company made the final cash dividend payment to the holders of record of the Series A and Series B Preferred Stock. The amount of the preferred stock dividends paid was as follows:

Series A Preferred Stock Dividends	$214,903
Series B Preferred Stock Dividends	131,289
Total Dividends	$346,192

The payment in kind to preferred stockholders was recorded at fair value using the valuation of the common stock performed by an outside consulting firm as further described in Note 8 – Fair Value Measurements, at the preferred conversion rate to common stock as of June 30, 2013 and December 31, 2013. Components of the total fair value of $4,133,380 for fiscal year 2014 and $5,412,281 for fiscal year 2013 for the preferred stock dividends consist of:

	December 31, 2014		December 31, 2013	
	Additional preferred shares	Dividends in kind	Additional preferred shares	Dividends in kind
Series A Preferred Stock	893	$3,299,603	1,033	$3,779,521
Series B Preferred Stock	536	$833,777	1,066	$1,632,760

Yuma Co. issued the above additional preferred shares to each class of preferred stock. The outstanding shares at December 31, 2014 and 2013 are as follows:

	Original shares	2013 stock dividends	Shares outstanding December 31, 2013	2014 stock dividends	Shares converted to common stock in 2014	Shares outstanding December 31, 2014
Series A Preferred Stock	14,605	1,033	15,638	893	(16,531)	-
Series B Preferred Stock	18,590	1,066	19,656	536	(20,192)	-

At the closing of the merger, the shares of Series A and Series B preferred stock were converted to common stock as reflected in the table below.

	Number of preferred shares	Conversion ratio to Yuma Co. common stock	Conversion ratio to Company common stock	Number of shares
Series A Preferred Stock	16,531	1.207101257	757.3374389993	15,112,295
Series B Preferred Stock	20,192	.508185000	757.3374389993	7,771,192

NOTE 11 – STOCK-BASED COMPENSATION

The Yuma Co. 2011 Stock Option Plan (the "Yuma Co. Plan") was adopted on June 21, 2011. On September 10, 2014, the shareholders of Pyramid adopted the 2014 Long-Term Incentive Plan (the "2014 Plan"). Under these plans, the Board of Directors is authorized to grant stock options, stock awards (including restricted stock and restricted stock unit awards) and performance awards to officers, directors, employees and consultants. At December 31, 2015, 4,307,672 shares of the 8,900,000 shares of Yuma common stock originally authorized under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted.

Restricted Stock – The Company granted restricted stock awards ("RSAs") under the Yuma Co. Plan and the 2014 Plan in 2013, 2014 and 2015. These restricted stock awards granted to officers, directors and employees generally vest in one-third increments over a three-year period, and are contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by the Company's transfer agent.

A summary of the status of the RSAs for employees and non-employee directors and changes for the year to date ended December 31, 2015 is presented below.

	Number of unvested RSA shares	Weighted average grant-date fair value
Unvested shares as of January 1, 2015	2,063,100	$3.40 per share
Granted on March 12, 2015	73,194	$1.38 per share
Granted on August 18, 2015	2,155,538	$0.61 per share
Granted on September 30, 2015	75,000	$0.48 per share
Granted on October 5, 2015	295,586	$0.50 per share
Vested on January 25, 2015	(65,638)	$3.14 per share
Vested on April 1, 2015	(1,272,834)	$3.16 per share
Vested on May 1, 2015	(6,232)	$2.39 per share
Vested on May 20, 2015	(76,744)	$3.96 per share
Vested on July 14, 2015	(29,789)	$3.89 per share
Vested on October 15, 2015	(48,747)	$2.74 per share
Vested on November 1, 2015	(6,232)	$2.39 per share
Vested on November 30, 2015	(16,157)	$3.88 per share
Vested on December 31, 2015	(106,280)	$3.88 per share
Forfeited	(690,392)	$1.72 per share
Unvested shares as of December 31, 2015	2,343,373	$0.98 per share

The weighted average grant-date fair value per RSA share granted was $3.87 for 2014 and $3.22 for 2013.

A summary of the status of the RSAs and changes for the year to date ended December 31, 2015 for former Yuma employees acting as consultants is presented below.

	Number of unvested	Weighted average

	RSA shares	fair value
Unvested shares as of January 1, 2015	-	
Granted November 30, 2015	45,297	$0.19 per share
Granted December 15, 2015	173,224	$0.19 per share
Vested on December 31, 2015	(47,460)	$0.19 per share
Unvested shares as of December 31, 2015	171,061	$0.19 per share

Stock compensation cost for consultants is adjusted at the end of each reporting period to reflect cost based on the closing stock price at the end of that reporting period. That price was $0.19 at December 31, 2015.

At December 31, 2015, total unrecognized RSA compensation cost of $1,247,595 is expected to be recognized over a weighted average remaining service period of 1.4 years.

Stock Appreciation Rights – In 2015, the Company also issued Stock Appreciation Rights ("SARs") for employees under the 2014 Plan, as follows:

	Number of unvested SARs	Weighted average grant-date fair value
Unvested shares as of January 1, 2015	-	
Granted on August 18, 2015	2,159,855	$0.318 per share
Forfeited	(371,155)	$0.318 per share
Unvested shares as of December 31, 2015	1,788,700	$0.318 per share

Weighted average assumptions used to estimate fair value were expected life of five years, 61.17% volatility, 1.60% risk-free rate, and zero annual dividends.

Below is a summary of the SARs and changes for the year to date ended December 31, 2015 for former Yuma employees acting as consultants.

	Number of unvested SARs	Weighted average fair value
Unvested shares as of January 1, 2015	-	
Granted on November 30, 2015	19,080	$0.036 per share
Granted on December 15, 2015	104,639	$0.036 per share
Unvested shares as of December 31, 2015	123,719	$0.036 per share

Stock compensation cost for consultants is adjusted at the end of each reporting period to reflect the cost based on the closing stock price at the end of that reporting period. That price was $0.19 at December 31, 2015 and was used to compute a new fair value of $0.036 per share. Weighted average assumptions used to estimate fair value were expected option life of .91 years, 130% volatility, 0.65% risk-free interest rate, and zero expected dividend rate.

At December 31, 2015, total unrecognized SAR compensation cost of $418,039 is expected to be recognized over a weighted average remaining service period of 1.5 years.

The SARs in the tables above have a weighted average exercise price of $.605 and an aggregate intrinsic value of zero. The Company intends to settle these SARs in equity, as opposed to cash.

Stock Options – Pyramid issued stock options as compensation to non-employee directors under the Pyramid Oil Company 2006 Equity Incentive Plan (the "Pyramid Plan"). The options vested immediately, and are exercisable for a five-year period from the date of the grant.

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The following is a summary of the Company's stock option activity.

	Options	Weighted-average exercise price	Weighted-average remaining contractual life (years)	Aggregate intrinsic value
Outstanding at December 31, 2014	105,000	$5.17	2.65	$-
Granted	-	-	-	-
Exercised	-	-	-	-
Forfeited	-	-	-	-
Outstanding at December 31, 2015	105,000	$5.17	2.65	$-
Vested at December 31, 2015	105,000	$5.17	2.65	$-
Exercisable at December 31, 2015	105,000	$5.17	2.65	$-

As of December 31, 2015, there were no unvested stock options or unrecognized stock option expenses.

The following table summarizes the information about stock options outstanding and exercisable at December 31, 2015.

	Options Outstanding			Options Exercisable	
Exercise price	Number of shares	Weighted-average remaining life (years)	Weighted average exercise price	Number of shares	Weighted average exercise price
$5.40	5,000	0.10	$5.40	5,000	$5.40
$5.16	100,000	2.77	$5.16	100,000	$5.16
	105,000			105,000	

Restricted Stock Units – On April 1, 2013, the Company granted 163 Restricted Stock Units (for Yuma Co. shares) or "RSUs" to employees. Based on the exchange ratio of the merger, the RSUs converted into 123,446 RSUs. Each RSU represents a contingent right to receive one share of the Company's common stock upon vesting. In order to vest, an employee must have continuous service with the Company from time of the grant through April 1, 2016, the vesting date. These RSUs are expected to be settled in cash; consequently, the awards are liability-based and the booked valuation will change as the market value for common stock changes. At December 31, 2015, the RSU's were valued at the common stock closing price of the Company on that date. Compensation expense is recognized over the three-year vesting period.

A summary of the status of the unvested RSUs and changes during the year ended December 31, 2015 is presented below.

	Number of unvested RSUs	Weighted average grant-date fair value
Unvested shares as of January 1, 2015	95,424	

		$2.72 per share
Forfeited	(15,146)	$2.72 per share
Unvested shares as of December 31, 2015	80,278	$2.72 per share

On December 25, 2014, the Company entered into a Separation Agreement and General Release of Claims ("Separation Agreement") with its former President and Chief Operating Officer which provided for, among other things, the forfeiture of 355,192 RSAs with various vesting dates and the issuance of an aggregate of 273,907 RSUs that vested December 31, 2014, with 254,973 to be issued on April 1, 2015 and 18,934 to be issued on May 20, 2015. These RSUs were valued under the equity method, and valued as of December 25, 2014.

NOTE 12 – EARNINGS PER COMMON SHARE

Earnings per common share are computed by dividing earnings available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Potential common stock equivalents are determined using the "if converted" method.

Potentially dilutive securities for the computation of diluted weighted average number of shares are as follows:

	Years Ended December 31, 2014		
	2015	2014	2013
Restricted Stock Awards	1,786,812	2,280,137	1,334,452
Stock Appreciation Rights	791,675	-	-
Restricted Stock Units	93,733	105,643	91,762
Series A Preferred Stock	-	10,031,104	12,964,860
Series B Preferred Stock	-	5,263,585	7,259,079
	2,672,220	17,680,469	21,650,153

The Series A and Series B Preferred Stock were converted to common stock on September 10, 2014, 253 days into the total 365 days for the twelve month period ended December 31, 2014. This shorter period accounts for the decrease in weighted average number of shares in the twelve months ended December 31, 2014 compared to the same period in 2013.

The Company excludes preferred stock and stock-based awards whose effect would be anti-dilutive from the calculation. For the years ended December 31, 2015, 2014 and 2013, adjusted earnings were losses, therefore common stock equivalents were excluded from the calculation of diluted net loss per share of common stock, as their effect was anti-dilutive.

NOTE 13 – DEBT AND INTEREST EXPENSE

	December 31, 2015	December 31, 2014
Variable rate revolving credit agreement payable to Société Générale, CIT Bank, NAC, and LegacyTexas Bank, maturing May 20, 2017, secured by the stock of Exploration and its interest in POL, and guaranteed by The Yuma Companies, Inc.	$29,800,000	$22,900,000
Installment loan due February 29, 2016, originating from the financing of insurance premiums at 3.74% interest rate.	108,894	-
Installment loan due June 11, 2016, originating from the financing of insurance premiums at 3.76% interest rate.	154,741	-
Installment loan due June 11, 2015, originating from the financing of insurance premiums at 3.76% interest rate.	-	154,750
Installment loan due February 28, 2015, originating from the financing of insurance premiums at 3.65% interest rate.	-	128,093
	30,063,635	23,182,843
Less: current portion	(30,063,635)	(282,843)
Total long-term debt	$-	$22,900,000

On August 10, 2011, Exploration entered into a $125.0 million syndicated credit agreement with Amegy Bank National Association ("Amegy") as Administrative Agent, or Agent Bank (the "credit agreement"). The maximum available under the revolving credit facility is determined by a formula based on the discounted value of the producing and non-producing crude oil and natural gas reserves (the borrowing base). Interest on the facility accrues at the Company's option based on prime as published by the Wall Street Journal, or a rate based on London Interbank Offering Rate ("LIBOR").

On September 24, 2012, the credit agreement was amended whereby Union Bank N. A. ("Union") joined the facility as a participant at 64.29% (Amegy was reduced to 35.71%) and replaced Amegy as Administrative Agent. Amegy, however, remained the Company's bank for regular operational banking functions.

On February 13, 2013, the credit agreement was further amended to add SocGen as a new participant and as a replacement for Union as the Administrative Agent, and to remove Amegy from the syndication. The participation allocation became 68.75% for SocGen and 31.25% for Union. The new interest rate margins effective February 13, 2013 are as follows:

Borrowing base utilization	Prime margin	LIBOR margin
Utilization > 90%	2.25%	3.25%
75% < utilization < 90%	2.00%	3.00%
50% < utilization < 75%	1.75%	2.75%
25% < utilization < 50%	1.50%	2.50%
Utilization < 25%	1.25%	2.25%

On May 20, 2013, a Third Amendment to the credit agreement added CIT Bank, NAC (“CIT”, previously OneWest Bank, FSB) to replace Union with the new participation for SocGen and CIT equal at 50/50. With the third amendment, the credit agreement maturity date was changed to May 20, 2017.

On September 27, 2013, the Borrowing Base Redetermination Agreement and Assignment added LegacyTexas Bank ("Legacy", previously View Point Bank, N.A.) as a third lender in the credit agreement. Participating percentages at September 27, 2013 became 37.5% for SocGen, 37.5% for CIT and 25% for Legacy.

Effective April 22, 2014, Exploration entered into the Fourth Amendment to the credit agreement, which among other things, provided for a borrowing base of $40.0 million.

On October 14, 2014, Exploration entered into the Fifth Amendment to the credit agreement to permit YEI to make dividend payments on the Series A Preferred Stock, subject to certain limitations.

On January 23, 2015, Exploration entered into the Sixth Amendment to the credit agreement. Pursuant to this amendment, (i) the borrowing base under the credit agreement remained at $40.0 million until the next borrowing base redetermination date which occurred on April 7, 2015, subject to a loan covenant requiring a ten percent availability under the line in order to pay dividends on any preferred stock, (ii) the Company could issue additional series of preferred stock subject to certain restrictions, (iii) the definition of "Change of Control" was amended and restated; (iv) the Company pledged the stock of Exploration; (v) Exploration pledged its interest in its wholly owned subsidiary, Pyramid Oil LLC ("POL"), and (vi) the oil and natural gas properties held by the Company in the state of California were transferred from the Company to POL and were mortgaged under the credit agreement. In addition, Exploration's properties in North Dakota were mortgaged.

On April 7, 2015, Exploration entered into the Seventh Amendment to the credit agreement, which reduced the Company's borrowing base to $33.0 million, with an additional $3.0 million non-conforming borrowing base that expired on September 1, 2015.

On July 7, 2015, Exploration entered into the Eighth Amendment to the credit agreement that changed the borrowing base to $33.5 million with a $1.5 million additional but non-conforming portion that expired on October 1, 2015. The banks participate in the Company's revolving line of credit at 37.5%, 37.5% and 25% for SocGen, CIT and Legacy, respectively. During September 2015, Legacy replaced Amegy as the Company's bank for treasury operations.

On December 30, 2015, Exploration entered into the Waiver, Borrowing Base Redetermination and Ninth Amendment to the credit agreement in which the borrowing base was reduced to $29.8 million and will automatically be reduced to $20 million on May 31, 2016 unless otherwise reduced by or to a different amount by the lenders under the credit agreement. This amendment also provided a waiver of the financial covenant related to the maximum permitted ratio of funded debt to EBITDA for the fiscal quarter ended September 30, 2015 and any failure to comply with that financial covenant and certain other financial covenants for the fiscal quarter ended December 31, 2015. Pursuant to the amendment, Exploration agreed that on or before February 6, 2016, it would engage an investment bank to explore strategic options for its finances and, on or before March 31, 2016, would either enter into an underwritten commitment for additional capital in an aggregate amount sufficient to pay any borrowing base deficiency then existing or enter into a definitive agreement for the acquisition by a third party of all or substantially all of the assets of Exploration and its subsidiaries by merger, asset purchase, equity purchase or other structure acceptable to the Administrative Agent and the lenders. On February 10, 2016, the Company entered into the merger agreement with Davis (see Note 24 – Subsequent Events), and expects to enter into another amendment to the credit agreement to account for the contemplated merger with Davis.

Costs and fees paid to the banks in connection with the revolving credit facility are amortized through May 31, 2016, due to the possible accelerated maturity date per the SocGen Ninth Amendment. SocGen, as Agent Bank, is also paid an annual administrative fee of $25,000 that is usually amortized over the year, but will also be amortized through May 31, 2016.

The following summarizes interest expense for the years ended December 31, 2015, 2014 and 2013.

	Years Ended December 31,		
	2015	2014	2013
Credit facility	$1,104,231	$1,109,153	$1,010,539
Credit facility commitment fees	34,512	70,813	56,092
Amortization and write offs of credit facility loan costs	286,009	188,669	480,261
Insurance installment loan	13,654	13,640	16,161
Louisiana Mineral Board	-	-	32,383
Other interest charges	1,489	3,275	4,056
Capitalized interest	(983,472)	(1,059,350)	(1,031,816)
Total interest expense	$456,423	$326,200	$567,676

The terms of the credit agreement require Exploration to meet a specific current ratio, interest coverage ratio, and a funded debt to EBITDA ratio. The credit agreement also contains a covenant requiring ten percent availability under the current borrowing line in order to pay dividends on the Series A Preferred Stock. In addition, the credit agreement requires the guarantee of YCI. Exploration was not in compliance with all of the loan covenants as of December 31, 2015; however, it received a waiver pursuant to the Waiver, Borrowing Base Redetermination and Ninth Amendment to the credit agreement dated December 30, 2015.

Aggregate principal payments based on the Company's current borrowings as of December 31, 2015 for the next five years are shown below:

2016	$30,063,635*
2017	-
2018	-
2019	-
2020	-

*Includes $29,800,000 for possible accelerated maturity per Ninth Amendment to the credit agreement which otherwise matures May 20, 2017.

NOTE 14 – MERGER WITH PYRAMID OIL COMPANY AND GOODWILL

On September 10, 2014, a wholly owned subsidiary of Pyramid merged with and into Yuma Co. in exchange for 66,336,701 shares of common stock and Pyramid changed its 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 Pyramid by Yuma Co. The transaction qualified as a tax-deferred reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended (the "Code").

As a result of the merger announcement with Pyramid on February 6, 2014, expenses of approximately $1.3 million previously incurred by the Company in connection with exploring options to obtain a public listing were written off during the first quarter of 2014.

The merger was accounted for as a business combination in accordance with ASC 805 Business Combinations ("ASC 805"). ASC 805, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values.

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A table of adjustments reflecting the allocation of the fair values and computation of goodwill is provided below. These adjustments reflect the elimination of the components of Pyramid's historical stockholders' equity, the estimated value of consideration paid by the Company in the merger using the closing price of its common stock on September 10, 2014, and the adjustments to the historical book values of Pyramid's assets and liabilities to their estimated fair values, in accordance with acquisition accounting. The Company believes the purchase price allocation is final as of the fourth quarter 2014 and that these estimates are reasonable and the significant effects of the merger are properly reflected.

	September 10, 2014 (as initially reported)	Measurement period adjustment (i)	September 10, 2014 (as adjusted)
Purchase Price(i):			
Shares of Pyramid common stock held by Pyramid shareholders	4,788,085	-	4,788,085
Pyramid common stock price (September 10, 2014 closing price)	$4.70	$ -	$4.70
Fair value of Pyramid common stock issued	$22,504,000	$ -	$22,504,000
Consideration paid to Pyramid's shareholders	-	-	-
Issuance of 100,000 shares to Pyramid affiliated persons at $5.01 per share (September 11, 2014 closing price)	501,000	-	501,000
Fair value of Pyramid options assumed by the Company(ii)	100,500	-	100,500
Total purchase price	23,105,500	-	23,105,500
Estimated Fair Value of Liabilities Assumed:			
Current liabilities	633,917	-	633,917
Noncurrent deferred tax liability(iii)	4,879,724	-	4,879,724
Other noncurrent liabilities (asset retirement obligation)	1,334,278	(390,327)	943,951
Amount attributable to liabilities assumed	6,847,919	(390,327)	6,457,592
Total purchase price plus liabilities assumed	29,953,419	(390,327)	29,563,092
Estimated Fair Value of Assets Acquired:			
Current assets	9,066,589	-	9,066,589
Oil and natural gas properties(iv)	10,726,715	-	10,726,715
Net other property and equipment	4,158,420	-	4,158,420
Other noncurrent assets	261,380	-	261,380
Amount attributable to assets acquired	24,213,104	-	24,213,104
Goodwill(i)	$5,740,315	$ (390,327)	$5,349,988

(i) Under the terms of the merger agreement, Pyramid shareholders retained 7% of the Company. The total purchase price was based upon the closing price of $4.70 per share of Pyramid common stock on September 10, 2014 and 4,788,085 shares of Pyramid common stock outstanding at the effective time of the merger. The difference between the purchase price plus the liabilities of Pyramid assumed in the merger less the estimated fair value of the Pyramid assets acquired was shown as goodwill.

During the fourth quarter 2014 (within the allowed measurement period for adjustments to goodwill), the Pyramid asset retirement obligation as of the merger date was re-evaluated for cost projections, asset lives were adjusted to reflect the updated reserve report, inflation factors were updated and the credit adjusted risk-free rate became based on the Company's outstanding debt cost. The result was a decrease of $390,327 to the liability and an equal decrease to goodwill.

(ii) To adjust for the outstanding stock options to purchase common stock that were assumed by the Company with the merger. The $100,500 fair value of the assumed options was calculated using the Black Scholes valuation model with assumptions for the following variables: common stock price, risk-free interest rates, and the Company's stock volatility.

(iii) The Company received a carryover tax basis in Pyramid's assets and liabilities because the merger was not a taxable transaction under the Code. Based upon the preliminary purchase price allocation, a step-up in financial reporting carrying value related to the property acquired from Pyramid, net of the existing Pyramid deferred tax asset of $0.5 million, is expected to result in a combined deferred tax liability of approximately $16.2 million, an increase of approximately $5.4 million to the Company's and Pyramid's existing $10.8 million net deferred tax liability.

(iv) Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was based on the NYMEX price forecasts as of August 29, 2014 for oil and September 2, 2014 for natural gas, adjusted for differentials calculated from the 2013 historic Pyramid oil and gas prices versus the NYMEX oil (WTI) and gas average monthly prices, after adjustment for transportation fees.

The drop in crude oil prices after the merger and the resulting decline in the Company's common share price caused the Company to test goodwill for impairment at June 30, 2015. Goodwill was determined to be fully impaired and as a result, the balance of $5,349,988 was written off. The following unaudited pro forma combined results of operations are provided for the years ended December 31, 2014 and 2013 as though the merger had been completed as of the beginning of the earliest period presented, or January 1, 2013. These pro forma combined results of operations have been prepared by adjusting the historical results of the Company to include the historical results of Pyramid. Pyramid's historical property impairment expenses recognized under the successful efforts method of accounting were eliminated as they would not have been incurred under full cost accounting. Pyramid's historical depletion of oil and gas property was also adjusted to reflect the change to full cost accounting. These supplemental pro forma results of operations are provided for illustrative purposes only, and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the merger or any estimated costs that will be incurred to integrate Pyramid. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Years Ended December 31,	
	2014	2013
Revenues	$46,238,208	$33,534,396
Net income (loss)	$(3,388,094)	$(7,834,907)
Net income (loss) per share:		
Basic	$(.07)	$(.19)
Diluted	$(.07)	$(.19)

For the year ended December 31, 2014, the Company recognized $945,580 of sales of natural gas and crude oil less lease operating expenses, production taxes and other operating expenses of $1,285,200 related to properties acquired in the merger. Additionally, non-recurring transaction costs of $2,226,719 and $124,222 related to the merger for the fiscal years 2014 and 2013, respectively, and costs of $1,287,285 to explore other options for a public listing expensed in 2014 are included in the Consolidated Statements of Operations as general and administrative expenses; however, these non-recurring transaction costs have been excluded from the pro forma results in the above table.

NOTE 15 – STOCKHOLDERS' EQUITY

Common Stock

The Company is authorized to issue up to 300,000,000 shares of common stock, no par value per share. The holders of common stock are entitled to one vote for each share of common stock, except as otherwise required by law. From the date of issuance of the Series A Preferred Stock (July 2011) and the Series B Preferred Stock (July and August 2012), until their conversion into common stock at the closing of the merger, no dividends could be declared or paid or set apart for payment and no other distribution could be declared or made or set apart for payment, in each case except for certain property distributions as defined in the Certificate of Incorporation of Yuma Co., and detailed in Note 7 – Related Party Transactions. In addition, during this period, holders of common stock could not vote on any amendment to the Certificate of Incorporation of Yuma Co. that related solely to the terms of the preferred stock.

Yuma Co. 2011 Stock Option Plan

Effective June 21, 2011, Yuma Co. adopted the 2011 Stock Option Plan ("Yuma Co. Plan"). The Yuma Co. Plan provided, among other things, for the granting of up to 6,000 (or approximately 4,544,025 shares based on the merger exchange ratio) shares of common stock as awards to key employees, officers, directors, and consultants of the Company by the Board of Directors. An award could take the form of stock options, SARs, RSAs or RSUs. At its meeting on August 1, 2014, the Board of Directors of Pyramid approved the assumption and amendment and restatement of the Yuma Co. Plan, which assumption was effective as of September 10, 2014 ("Plan Effective Date"). Following the Plan Effective Date, there were approximately 2,454,785 shares of common stock that were subject to outstanding RSAs and RSUs granted by Yuma Co. under the Yuma Co. Plan and that were assumed by the Company. Further, on September 11, 2014, the Board determined that no additional awards would be granted under the Yuma Co. Plan, and that the 2014 Plan would be used going forward.

2014 Long-Term Incentive Plan

On August 1, 2014, the board of directors of Pyramid adopted the 2014 Long-Term Incentive Plan (the "2014 Plan"), subject to shareholder approval at the 2014 Special Meeting of Shareholders. The shareholders of Pyramid approved this proposal at the Special Meeting held September 10, 2014 and became effective as of that date.

Under the 2014 Plan, YEI may grant stock options, RSAs, RSUs, SARs, performance units, performance bonuses, stock awards and other incentive awards to YEI employees or those of YEI's subsidiaries or affiliates. YEI may also grant nonqualified stock options, RSAs, RSUs, SARs, performance units, stock awards and other incentive awards to any persons rendering consulting or advisory services and non-employee directors, subject to the conditions set forth in the 2014 Plan. Generally, all classes of YEI's employees are eligible to participate in the 2014 Plan.

The 2014 Plan provides that a maximum of 8,900,000 shares of common stock may be issued in conjunction with awards granted under the 2014 Plan. Awards that are forfeited under the 2014 Plan will again be eligible for issuance as though the forfeited awards had never been issued. Similarly, awards settled in cash will not be counted against the shares authorized for issuance upon exercise of awards under the 2014 Plan.

The 2014 Plan provides that a maximum of 1,000,000 shares of common stock may be issued in conjunction with incentive stock options granted under the 2014 Plan. The 2014 Plan also limits the aggregate number of shares of common stock that may be issued in conjunction with stock options and/or SARs to any eligible employee in any calendar year to 1,500,000 shares. The 2014 Plan also limits the aggregate number of shares of common stock that may be issued in conjunction with the grant of RSAs, RSUs, performance unit awards, stock awards and other incentive awards to any eligible employee in any calendar year to 700,000 shares.

NOTE 16 – INCOME TAXES

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently due plus deferred taxes related primarily to differences between the basis of property and equipment for financial reporting versus income tax reporting. The deferred taxes represent the future tax return consequences of those differences that will either be taxable or deductible when the differences in the basis of assets and liabilities reverse.

The Company recognizes and measures income tax benefits that are more likely than not to be sustained on eventual examination or settlement. Deferred tax assets are recorded to the extent the Company believes these assets will more likely than not be realized.

The Company does not have any unrecognized tax benefits for the years ended December 31, 2015, 2014 and 2013. In addition, the Company does not anticipate any unrecognized tax benefits during the next twelve months from the date these financials were available to be issued, March 29, 2016.

The Company did not incur any income tax deficiencies during fiscal years 2012, 2013, 2014, and 2015, and therefore had no interest or penalties assessed during the years ended December 31, 2012, 2013, 2014, and 2015.

The tax years of the Company that remain subject to examination by the Internal Revenue Service and other tax authorities are fiscal years 2012, 2013, 2014 and 2015.

The Company follows the liability and asset approach in accounting for income and state franchise taxes as required by the provisions of FASB concerning accounting for income taxes. Deferred tax liabilities and assets are determined using the tax rates for the period in which those accounts are expected to be paid or received.

Provisions for income taxes are composed of the following for the years ended December 31, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
Current income taxes (benefit):			
Federal	$(29,226)	$-	$-
State	(1,963)	-	-
Total	(31,189)	-	-
Deferred income taxes (benefit):			
Federal	(7,227,361)	(2,377,192)	2,705,688
State	(724,489)	(176,662)	374,584
Total	(7,951,850)	(2,553,854)	3,080,272
Total taxes (benefit) on income	$(7,983,039)	$(2,553,854)	$3,080,272

Deferred tax liabilities (assets) that are recognized for the estimated future tax effects attributable to temporary differences and carryforwards at year-end are as follows:

	Years Ended December 31, 2015	2014
Deferred tax liability (hedges)	$-	$1,843,409
Deferred tax liability from excess of book basis over tax basis of certain assets including property, plant and equipment	30,009,264	30,081,226
Deferred tax liability	30,009,264	31,924,635
Stock-based compensation	(608,442)	(1,205,722)
Alternative minimum tax credit carryforwards	(121,686)	(121,686)
Net operating loss (“NOL”) carryforwards	(22,481,966)	(15,585,820)
Other deferred tax (asset)	-	(396,668)
Deferred tax asset	(23,212,094)	(17,309,896)
Net deferred tax liability	$6,797,170	$14,614,739

The deferred tax assets at December 31, 2015 and 2014 of $23,212,094 and $17,309,896, respectively, consist of deductible temporary differences related to operating loss carryforwards, unrealized losses from oil and natural gas hedges, and tax credit carryforwards and stock-based compensation generated by the consolidated group:

Year NOL generated	NOL remaining	Year of expiration
2015	$ 14,926,752	2035
2014	14,943,985	2034
2013	9,417,693	2033
2012	8,082,421	2032
2011	5,511,938	2031
2009	4,844,318	2029
2007	1,095,474	2027
2002	3,050,662	2022
Total	$ 61,873,243	

The Company retroactively early adopted Accounting Standards Update 2015-14 during the fourth quarter of 2015 which requires the presentation of deferred tax assets and liabilities as noncurrent in the Consolidated Balance Sheet. See Note 1 - Summary of Significant Accounting Policies, Changes in Accounting Principles for further information regarding the adoption of Accounting Standards Update 2015-14.

The tax provisions differ from the amounts that would be calculated by using federal statutory rate of 35 percent to calculate income taxes because (i) no tax benefit has been recognized for nondeductible expenses; (ii) the Companies are subject to various state income taxes; and (iii) the tax provisions consider the effect of graduated rates, as follows:

	Years Ended December 31, 2015	2014	2013
Amount computed using the statutory rate	$ (6,645,827)	$ (7,972,651)	$ (10,489,441)
Increase (reduction) in taxes resulting from:			
Non-deductible change in value of preferred stock derivative liability	-	5,486,895	9,190,496
State taxes	(726,452)	(210,021)	254,645
Other	(610,760)	141,923	4,124,572
Income tax expense (benefit)	$ (7,983,039)	$ (2,553,854)	$ 3,080,272

For the year ended December 31, 2013, the Other, net amount relates primarily to changes in estimates to net operating losses, depletion and amortization.

When the Company believes that it is more likely than not that a net operating loss or credit carryforward may expire unused, it establishes a valuation allowance against the loss or credit. No valuation allowance has been established as of December 31, 2015, 2014 or 2013. Income taxes are allocated among the companies in the consolidated group on the basis of the tax effect each company contributed to income taxes for the years 2015 and 2014.

NOTE 17 – CONTINGENCIES

Certain Legal Proceedings

From time to time, the Company is party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, the Company is not currently a party to any proceeding that it believes, if determined in a manner adverse to the Company, could have a potential material adverse effect on its financial condition, results of operations, or cash flows.

On July 9, 2014, Nabors Drilling USA, L.P. and other Nabors entities and Yuma Energy, Inc. and several of its wholly owned subsidiaries were named in a lawsuit filed in the District Court of Harris County, Texas, in the 80th Judicial District, concerning the death of an employee of Timco Services during the drilling of the Crosby 12-1 well. The Company has tendered its defense to its liability insurance carriers who are responding. There has been one unsuccessful mediation session. Depositions are being scheduled. Management believes that the Company has adequate insurance to meet this potential claim.

In September 2015, a suit was filed against the Company and Pyramid Oil LLC styled Mark A. Ontiveros and Louise D. Ontiveros, Trustees of The Ontiveros Family Trust dated March 29, 2007 vs. Pyramid Oil, LLC, et al. In the suit, the plaintiffs allege that the 1950 Community Oil and Gas Lease between them and Pyramid Oil LLC has expired by non-production. The Company claims that the lease is still in effect, as there is no cessation of production time frame set out in the lease; production had temporarily ceased, but was still profitable when measured over an appropriate time period; and the Company was conducting workover operations on a well on the lease in an effort to re-establish production when served with the quit claim deed demand from the plaintiff's attorney. All present owners of the minerals covered by the 1950 Community Oil and Gas Lease, with the exception of the plaintiffs and one other owner, have executed amendments signifying their concurrence that the 1950 Community Oil and Gas Lease is still in force and effect. The parties are presently in the process of document discovery.

Environmental Remediation Contingencies

As of December 31, 2015, there were no known environmental or other regulatory matters related to the Company's operations that were reasonably expected to result in a material liability to the Company. The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Exploration has been named as one of 97 defendants in a matter entitled Board of Commissioners of the Southeast Louisiana Flood Protection Authority – East, Individually and As the Board Governing the Orleans Levee District, the Lake Borgne Basin Levee District, and the East Jefferson Levee District v. Tennessee Gas Pipeline Company, LLC, et al., Civil District Court for the Parish of Orleans, State of Louisiana, No. 13-6911, Division "J" - 5, now removed as Civil Action No. 13-5410, before the United States District Court, Eastern District of Louisiana. Plaintiff filed the suit on July 24, 2013 seeking damages and injunctive relief arising out of defendants' drilling, exploration, and production activities from the early 1900s to the present day in coastal areas east of the Mississippi River in Southeast Louisiana.

The suit alleges that defendants' activities have caused "removal, erosion, and submergence" of coastal lands resulting in significant reduction or loss of the protection such lands afforded against hurricanes and tropical storms. Plaintiff alleges that it now faces increased costs to maintain and operate the man-made hurricane protection system and may reach the point where that system no longer adequately protects populated areas.

Plaintiff lists hundreds of wells, pipelines, and dredging events as possible sources of the alleged land loss. Exploration is named in association with 11 wells, four rights-of-way, and one dredging permit. The suit does not specify any deficiency or harm caused by any individual activity or facility.

Although the suit references various federal statutes as sources of standards of care, plaintiff claims that all causes of action arise under state law: negligence, strict liability, natural servitude of drain, public nuisance, private nuisance, and as third-party beneficiary under breach of contract.

The Company tendered its defense to its liability insurance carriers, who are responding. On February 13, 2015, the federal judge adjudicating the matter granted defendants "Joint Motion to Dismiss for Failure to State a Claim Under Rule 12(b)(6)", thereby dismissing plaintiff's claims with prejudice in the matter. On February 20, 2015, the Board of Orleans filed a notice of appeal to the U.S. Fifth Circuit. On February 29, 2016, oral arguments were held regarding the appeal, but as of March 29, 2016, no ruling on the appeal has been made. The Company will continue to contest plaintiff's legal arguments and factual assertions. At this point in the legal process, no evaluation of the likelihood of an unfavorable outcome or associated economic loss can be made; therefore no liability has been recorded on the Company's books.

Escheat Audits

The States of Louisiana, Texas, Minnesota and Wyoming have notified the Company that they will examine the Company's books and records to determine compliance with each of the examining state's escheat laws. The review is being conducted by Discovery Audit Services, LLC. The Company has engaged Ryan, LLC to represent it in this matter. The exposure related to the audits is not currently determinable.

NOTE 18 – EMPLOYEE BENEFIT PLANS

The Company has a defined contribution 401(k) plan (the "Plan") for its qualified employees. Employees may contribute any amount of their compensation to the Plan, subject to certain Internal Revenue Service annual limits and certain limitations for employees classified as high income. The Plan provides for discretionary matching contributions by the Company, and the Company currently provides a match for non-highly compensated employees only at a rate of 100 percent of each employee's contribution up to 4 percent of the employee's base salary. The Company contributed $56,051 and $38,827 under the Plan for the years ended December 31, 2015 and 2014, respectively.

The Company provides medical, dental, and life insurance coverage for both employees and dependents, along with disability and accidental death and dismemberment coverage for employees only. The Company pays the full cost of coverage for all insurance benefits except medical. The Company's contribution toward medical coverage is 85 percent for the employee portion of the premium, and a variable percentage of the dependent portion, depending on employee compensation levels.

The Company offers paid vacations to employees in time increments determined by longevity and individual employment contracts. The Company policy provides a limited carry forward of vacation time not taken during the year. The Company recorded an accrued liability for compensated absences of $138,962 and $166,660 for the years ended December 31, 2015 and 2014, respectively.

The Company maintains employment contracts with members of its exploration staff and with certain key employees of the Company. As of December 31, 2015, future employment contract salary commitments were $1,399,242, excluding automatic renewals, evergreen and month-to-month provisions, and potential Annual Incentive Plan awards as described below.

The Company adopted the 2014 Plan as described in Note 15 – Stockholders' Equity. Note 11 – Stock-Based Compensation describes restricted stock awards granted under the 2014 Plan.

During December 2011, the Company adopted an employee Annual Incentive Plan ("AIP"). Under the AIP, the Board of Directors establishes certain performance metrics by which management is to be measured annually. These metrics are determined annually and awards of restricted stock, cash, or some combination of both may be made to members of the management team. The Board of Directors will meet during 2016 to evaluate the management team and determine any awards that may be due for 2015. To the extent compensation costs relate to employees directly involved in exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expense.

NOTE 19 – FINANCIAL INSTRUMENTS WITH OFF-BALANCE SHEET RISK, CONCENTRATIONS OF CREDIT RISK, AND CONCENTRATIONS IN GEOLOGIC PROVINCES

Off-Balance Sheet Risk

The Company does not consider itself to have any material financial instruments with off-balance sheet risks.

Concentrations of Credit Risk

The Company maintains cash deposits with banks that at times exceed applicable insurance limits. The Company reduces its exposure to credit risk by maintaining such deposits with high quality financial institutions. The Company has not experienced any losses in such accounts.

Substantially all of Exploration's accounts receivable result from oil and natural gas sales, joint interest billings and prospect sales to oil and natural gas industry partners. This concentration of customers, joint interest owners and oil and natural gas industry partners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic and other conditions. Such receivables are generally not collateralized; however, certain crude oil purchasers have been required to provide letters of guaranty from their parent companies.

Concentrations in Geologic Provinces

The Company has a significant portion of its crude oil production and associated infrastructure concentrated in state waters and coastal bays of Louisiana. These properties have exposure to named windstorms. The Company carries appropriate property coverage limits, but does not carry business interruption coverage for the potential lost production. The Company has changed its strategic direction to focus on onshore geological provinces which the Company believes have little or no hurricane exposure.

NOTE 20 – OTHER DISCLOSURES

Other Operating Expenses

	December 31, 2015	2014	2013
Bad debt expense	$839,171	$97,068	$193,601
Recovery of bad debts	(342,944)	(1,984)	(2,520)
Loss (gain) on disposal of property	(28,006)	3,392	(19,307)
Total	$468,221	$98,476	$171,774

Other Non-Operating Income (Expense)

	December 31, 2015	2014	2013
Interest income	$19,587	$23,632	$7,336
Rental income	16,000	-	-
Bank-mandated derivative instruments novation cost	-	-	(175,000)
Louisiana sales tax settlement	-	-	(44,149)
Louisiana Mineral Board audit	-	-	(23,686)
Other	751	1,746	(5,118)
Total	$36,338	$25,378	$(240,617)

Other Receivables

	December 31, 2015	2014
December 2015 and December 2014 settled oil derivative instruments	$257,286	$407,003
Tax refund	177,157	158,571
Debit balances for trade payables	109,586	187,031
Refund from PPI for duplicate charges	89,544	89,544
D&O insurance premium adjustment	-	16,356
Other	-	(1,943)
Total	$633,573	$856,562

Prepayments

	December 31, 2015	2014
Insurance	$570,379	$536,410
Taxes and fees	39,687	21,882
Property taxes	41,583	56,992
Other subscriptions	16,508	6,355
Software maintenance agreements	14,572	19,105
Geological well database subscription	8,883	19,055
Software licenses	2,065	44,172
Exploration and drilling costs	-	71,893
Services	-	4,530
Other	10,846	1,840
Total	$704,523	$782,234

Other Current Deferred Charges

	December 31, 2015	2014
Loan fees	$415,740	$189,409
Deferred premium on 2015 oil derivative instruments	-	153,389
Total	$415,740	$342,798

Other Noncurrent Assets

	December 31, 2015	2014
Deferred offering costs	$38,104	$-
Loan fees	-	262,200
Total	$38,104	$262,200

Other Accrued Liabilities

	December 31, 2015	December 31, 2014
Employee termination benefits	$422,037	$-
Salaries and bonuses	393,072	479,537
Accounting and audit	202,297	22,964
Severance taxes	157,941	164,374
Ad valorem taxes	143,957	172,444
Vacation	138,962	166,660
Sales and use tax	85,076	81,661
Insurance	67,532	119,121
Fees for commodity hedging advisor	64,953	48,590
Interest expense	39,471	9,327
Financing cost	35,000	-
Employee restricted stock unit awards	13,981	-
Commodity hedge settlement	-	153,389
Other	17,205	1,498
Total	$1,781,484	$1,419,565

NOTE 21 – SALES TO MAJOR CUSTOMERS

The Company generally sells crude oil and natural gas to numerous customers on a month-to-month basis. Three customers accounted for approximately 67 and 73 percent of unaffiliated oil and natural gas sales in the years ended December 31, 2015 and 2014, respectively. Four customers accounted for approximately 78 percent of unaffiliated oil and natural gas sales in the year ended December 31, 2013.

NOTE 22 – LEASES

The Company leases its primary office space of 15,180 square feet for $23,403 per month, plus $50 per month for each employee or contractor parking space. The lease term expires on December 31, 2017. On November 1, 2012, the monthly rent was reduced to $21,821 on a triple-net basis, and then escalated by 1.45 percent for the period November 1, 2013 through October 31, 2014. The lease then escalates by approximately 2.8 percent each year thereafter.

The Company currently leases approximately 3,200 square feet of office space at an off-site location as a storage facility. The current lease expires on April 30, 2017. The lease called for a security deposit of $2,684, and monthly rent of $1,949 commencing on May 1, 2014, escalating to $2,045 on May 1, 2015 and $2,141 on May 1, 2016.

Aggregate rental expense for fiscal years 2015, 2014 and 2013 was $575,905, $531,127 and $534,275, respectively. As of December 31, 2015, future minimum rentals under all noncancellable operating leases are as follows:

2016	579,873
2017	564,326
2018	2,264
2019	-
2020	-

NOTE 23 – AT MARKET SECURITY SALES

The Company entered into an At Market Issuance Sales Agreement (“Sales Agreement”) with an investment banking firm (the “Agent”) on December 19, 2014. Under the Sales Agreement, the Company may sell both common stock and Series A Preferred Stock pursuant to the Registration Statement on Form S-3 of the Company filed on November 5, 2013 (Registration No. 333-192094), which became effective under the Securities Act on November 21, 2013. Upon the Company’s delivery and the Agent’s acceptance of a placement notice, the Agent will use its commercially reasonable efforts, consistent with its sales and trading practices, to sell any shares subject to the placement notice. The Company initiated the sales of securities under the Sales Agreement on February 18, 2015, and as of December 31, 2015, the Company has sold the following securities for the net proceeds listed below (the Company made no sales of securities during the third or fourth quarters of 2015).

	Shares	Net Proceeds
Common Stock	1,347,458	$1,363,160
Series A Preferred Stock	46,857	870,386
Total		$2,233,546

NOTE 24 – SUBSEQUENT EVENTS

The Company has evaluated subsequent events through March 29, 2016, the date these financial statements were available to be issued. The Company is not aware of any subsequent events which would require recognition or disclosure in the financial statements, except as noted below or already recognized or disclosed.

Agreement and Plan of Merger and Reorganization

On February 10, 2016, YEI and privately held Davis Petroleum Acquisition Corp. (“Davis”) entered into a definitive merger agreement for an all-stock transaction. Upon completion of the transaction, YEI will reincorporate in Delaware, implement a one for ten reverse split of its common stock, and convert each share of its existing Series A Preferred Stock into 35 shares of common stock prior to giving effect for the reverse split (3.5 shares post reverse split). Following these actions, YEI will issue additional shares of common stock in an amount sufficient to result in approximately 61.1% of the common stock being owned by the current common stockholders of Davis. In addition, YEI will issue approximately 3.3 million shares of a new Series D preferred stock to existing Davis preferred stockholders, which is estimated to have a conversion price of approximately $5.70 per share, after giving effect for the reverse split. The Series D preferred stock is estimated to have a liquidation preference of approximately $18.7 million at closing, and will be paid dividends in the form of additional Series D preferred stock at a rate of 7% per annum. Upon closing, there will be an aggregate of approximately 23.7 million shares of common stock outstanding (after giving effect to the reverse stock split and conversion of Series A Preferred Stock to common stock). The transaction is expected to qualify as a tax-deferred reorganization under Section 368(a) of the Code.

The merger agreement is subject to the approval of the shareholders of both companies, as well as other customary approvals, including authorization to list the newly issued shares on the NYSE MKT. The parties anticipate completing the transaction in mid-2016.

Greater Masters Creek Field Area

During the first quarter of 2016, the Company shut-in 14 Austin Chalk wells in Beauregard, Rapides and Vernon Parishes, Louisiana due to low oil and natural gas prices. If production is not restarted from these wells, the associated leases will expire, reducing the Company’s proved reserves by approximately 1,629 MBoe, acreage by 22,021 gross

(18,140 net) acres, operated proved undeveloped locations by three, and operated non-proved undeveloped locations by seven.

During the first quarter of 2016, the Company received notice from the operator of certain wells in Rapides and Vernon Parishes, Louisiana, that certain wells in which the Company has an interest were shut-in due to current economic conditions. The operator plans to sell their interest. If the operator does not restart production from these wells or if a subsequent operator does not restart production from these wells, the associated leases will expire, which would reduce the Company's proved reserves by approximately 285 MBoe, acreage by 18,895 gross (3,737 net) acres, non-operated proved undeveloped locations by three, and non-operated non-proved undeveloped locations by 18.

The Company is currently negotiating with a certain mineral owner to amend the oil and gas lease agreement to extend the expiration date of certain acreage that is not held by production as of March 29, 2016. The total acreage is approximately 25,139 acres which will expire July 1, 2016 unless the Company initiates drilling of a development well on the pooled lands or pays a deferred development payment by July 1, 2016. If the leased acreage expires, the Company's proved reserves would be reduced by approximately 5,096 MBoe, the number of operated proved undeveloped locations and operated non-proved locations would be reduced by 13 and 16, respectively.

Texas Southeastern Gas Marketing Company

As of January 1, 2016, the Company decided to discontinue the operations of Texas Southeastern Gas Marketing Company due to the limited volumes of natural gas that it marketed, as well as the costs associated with accounting for the entity.

NOTE 25 – SUPPLEMENTARY INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration and development activities, all of which are conducted within the continental United States, are summarized below:

	December 31,		
	2015	2014	2013
Property acquisition costs - unproved	$(9,635,309)	$1,105,782	$3,865,932
Property acquisition costs - proved	7,587,965	3,349,473	8,539,134
Sales proceeds - unproved	(30,442)	(359,667)	(679,266)
Sales proceeds - proved	-	(307,600)	(718,000)
Exploration costs	3,217,161	426,909	2,504,087
Development costs	1,121,654	20,139,409	11,910,179
Capitalized asset retirements costs	4,301,810	241,629	5,795,400
Total costs incurred	$6,562,839	$24,595,935	$31,217,466

The Company sells oil and natural gas prospects. The gains or losses from these sales are recorded as adjustments to the full cost pool under U.S. Securities and Exchange Commission ("SEC") guidelines. Prospect profits were $30,442, $28,616 and $50,346 for fiscal years 2015, 2014 and 2013, respectively.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to natural gas and crude oil producing activities and the total amount of related accumulated depreciation, depletion and amortization:

	December 31, 2015	December 31, 2014
Oil and gas properties, full cost method:		
Not subject to amortization:		
Prospect inventory	$7,719,857	$14,913,126
Property acquisition costs - unproved	6,150,862	8,623,344
Well development costs - unproved	417,997	2,170,582
Subject to amortization:		
Property acquisition costs - proved	58,393,861	50,744,401
Well development costs - proved	81,063,335	74,440,227
Capitalized costs - unsuccessful	60,549,824	52,539,407
Capitalized asset retirement costs	4,505,018	8,806,828
Total capitalized costs	218,800,754	212,237,915
Less accumulated depreciation, depletion and amortization	(117,304,945)	(103,929,493)
Net capitalized costs	$101,495,809	$108,308,422

Reserves

Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geosciences 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules, the price is calculated using 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 (if the first day of the month occurs on a weekend or holiday, the previous business day is used), unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. A project to extract 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 natural gas or oil on the basis of available geosciences and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geosciences, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

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Developed natural gas and oil reserves are reserves of any category 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.

The information below on the Company's natural gas and oil reserves is presented in accordance with regulations prescribed by the SEC, with guidelines established by the Society of Petroleum Engineers' Petroleum Resource Management System, as in effect as of the date of such estimates. The Company's reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. Such changes could be material and could occur in the near term.

The Company does not prepare engineering estimates of proved oil and natural gas reserve quantities for all wells. The Company only prepares engineering studies of estimated oil and natural gas quantities on a consolidated basis. The Company has a quantity of interests that, individually, are immaterial and are excluded from prepared engineering studies. Accounting sales volumes and receipts differ from amounts prepared by internal engineers and included in the following tables.

	2015	2014	2013
Barrels of oil and condensate:			
Proved developed and undeveloped reserves:			
Beginning of year	14,011,343	14,381,960	7,739,964
Revisions of previous estimates	(5,596,379)	(565,143)	(1,142,654)
Purchases of oil and gas properties	103,387	472,132	7,959,600
Extensions and discoveries	769,661	51,993	92,152
Sale of oil and gas properties	-	-	-
Production	(321,687)	(329,599)	(267,102)
End of year	8,966,325	14,011,343	14,381,960
Proved developed reserves - January 1,	2,347,482	2,099,701	1,474,015
Proved developed reserves - December 31,	2,117,559	2,347,482	2,099,701
Proved undeveloped reserves - January 1,	11,663,861	12,282,259	6,265,949
Proved undeveloped reserves - December 31,	6,848,766	11,663,861	12,282,259

	2015	2014	2013
Thousands of cubic feet of natural gas:			
Proved developed and undeveloped reserves:			
Beginning of year	35,259,522	38,372,369	31,071,137
Revisions of previous estimates	(11,436,325)	(479,438)	(8,281,139)
Purchases of oil and gas properties	264,981	81,177	16,495,803
Extensions and discoveries	3,675,358	-	362,806
Sale of oil and gas properties	-	-	-
Production	(1,993,842)	(2,714,586)	(1,276,238)
End of year	25,769,694	35,259,522	38,372,369
Proved developed reserves - January 1,	7,786,537	10,316,516	10,156,754
Proved developed reserves - December 31,	8,552,249	7,786,537	10,316,516
Proved undeveloped reserves - January 1,	27,472,985	28,055,853	20,914,383
Proved undeveloped reserves - December 31,	17,217,445	27,472,985	28,055,853

Revisions in 2015 to previously estimated reserves for both natural gas and crude oil were primarily caused by (i) commodity price reductions of 6,771,739 Mcf of natural gas and 3,427,849 Boe of oil and condensate causing wells to reach their economic limits sooner and causing some proved undeveloped locations to become uneconomic; (ii) upward revisions of 2,337,685 Mcf of natural gas and 1,127,131 Boe of oil and condensate primarily associated with increased performance of Bayou Hebert (La Posada) field; and (iii) reclassifying PUD reserves of 7,002,271 Mcf and 3,295,661 Boe of oil and condensate to probable reserves primarily in Masters Creek due to the current economic conditions and uncertainty in future development plans.

Internal Controls Over Reserve and Future Net Revenue Estimation

The Company’s principle engineer is the Executive Vice President and Chief Operating Officer and is the person primarily responsible for overseeing the preparation of the Company’s internal reserve estimates and for overseeing the independent petroleum engineering firm during the preparation of the Company’s reserve report. His experience includes among other things, detailed evaluation of reserves and future net revenues for acquisitions, divestments, bank financing, long range planning, portfolio optimization, strategy and end of year financial reports. He has a B.S. in Petroleum Engineering from Louisiana Tech University and is a member of the Society of Petroleum Engineers (the “SPE”). His professional qualifications meet or exceed 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. The Executive Vice President and Chief Operating Officer reports directly to the Company’s Chief Executive Officer.

At December 31, 2015, 2014 and 2013, Netherland, Sewell & Associates, Inc. performed an independent engineering evaluation in accordance with the definitions and regulations of the SEC to obtain an independent estimate of the Company’s proved reserves and future net revenues.

Third Party Procedures and Methods Review

The review consisted of 34 fields which included the Company's major assets in the United States and encompassed 100 percent of the Company's proved reserves and future net cash flows as of December 31, 2015, 2014, and 2013. The Chief Operating Officer and the reservoir engineering staff presented the outside engineering firm with an overview of the data, methods and assumptions used in estimating reserves and future net revenues for each field. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating expenses and other relevant economic criteria.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures from the FASB concerning disclosures about oil and gas producing activities, and based on natural gas and crude oil reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and oil and natural gas sales prices will probably differ from the average annual prices required to be used in these calculations;
- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- A 10 percent discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and
- Future net revenues may be subject to different rates of income taxation.

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved crude oil and natural gas reserves as of year-end is shown for Exploration for fiscal years 2015, 2014 and 2013.

	December 31,		
	2015	2014	2013
Future cash inflows	$438,816,500	$1,339,372,300	$1,450,469,000
Future oil and natural gas operating expenses	(129,636,500)	(322,298,300)	(334,883,800)
Future development costs	(126,463,700)	(405,900,900)	(424,256,900)
Future income tax expenses	(23,334,886)	(133,467,940)	(163,704,120)
Future net cash flows	159,381,414	477,705,160	527,624,180
10% annual discount for estimating timing of cash flows	(53,318,652)	(183,249,968)	(202,270,201)
Standardized measure of discounted future net cash flows	$106,062,762	$294,455,192	$325,353,979

Estimates of future net cash flows from proved reserves of gas, oil, and condensate for fiscal years 2015, 2014 and 2013 are computed using the average first-day-of-the-month price during the 12-month period. Prices used in computing year-end future cash flows were $50.28, $91.48 and $96.94 for crude oil and $2.59, $4.35 and $3.67 for natural gas for fiscal years 2015, 2014 and 2013, respectively.

The ceiling test for many companies following the full cost method of accounting for oil and natural gas properties, including the Company, could be negatively impacted by prolonged unfavorable crude oil and natural gas prices. Future operating expenses and development costs are computed primarily by the Company's petroleum engineer by estimating the expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves at the end of the year, based on the year-end costs and assuming continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of ten percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Change in Standardized Measure

Changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves for Exploration are summarized below:

	2015	2014	2013
Changes due to current year operation:			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$(7,069,544)	$(25,270,455)	$(17,255,824)
Extensions and discoveries	16,660	2,743,800	37,750,617
Purchases of oil and gas properties	2,268,907	12,827,533	215,427,459
Development costs incurred during the period that reduced future development costs	4,052,919	9,178,400	100,500
Changes due to revisions in standardized variables:			
Prices and operating expenses	(373,506,778)	(42,125,763)	(30,773,529)
Income taxes	65,424,175	19,303,313	(38,340,467)
Estimated future development costs	245,056,050	7,218,529	32,430,504
Quantity estimates	(80,454,131)	(21,028,476)	(107,070,514)
Sale of reserves in place	-	-	-
Accretion of discount	37,672,481	43,124,820	27,910,664
Production rates, timing and other	(81,853,169)	(36,870,488)	(6,378,317)
Net change	(188,392,430)	(30,898,787)	113,801,093
Beginning of year	294,455,192	325,353,979	211,552,886
End of year	$106,062,762	$294,455,192	$325,353,979

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pre-tax results. Sales of oil and natural gas properties, extensions and discoveries, purchases of minerals in place and the changes due to revisions in standardized variables are reported on a pre-tax discounted basis.