SECURITIES & EXCHANGE COMMISSION EDGAR FILING

Yuma Energy, Inc.

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

FORM 10-K

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

For the fiscal year ended December 31, 2017

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

For the transition period from to

Commission File Number: **001-37932**

YUMA ENERGY, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	**94-0787340**
(State or other jurisdiction of incorporation or organization)	*(IRS Employer Identification No.)*
1177 West Loop South, Suite 1825 **Houston, Texas**	**77027**
(Address of principal executive offices)	*(Zip Code)*

(713) 968-7000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value per share	**NYSE American**

Securities registered pursuant to Section 12(g) of the Act: None.

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

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

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

Indicate by check mark 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). ☒ 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. ☒

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☒
		Emerging growth company	☐

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price of $0.93 per share at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was approximately $9,480,489.

At April 2, 2018, 23,230,169 shares of the Registrant's common stock, $0.001 par value per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for its 2018 Annual Meeting of Stockholders (the "Proxy Statement"), are incorporated by reference into Part III of this report Annual Report on Form 10-K.

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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,” “continue,” “believes,” “anticipates,” “expects,” “estimates,” “predicts,” or “potential,” the negative of such terms or variations thereon, or 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 prices for oil and natural gas and the effect of prices set or influenced by actions of the Organization of the Petroleum Exporting Countries (“OPEC”) and other oil and natural gas producing countries;
- 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 and higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;
- our ability to successfully develop our 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 and 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 effect of our oil and natural gas derivative activities;
- our insurance coverage may not adequately cover all losses that we may sustain;
- 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. You should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made.

Glossary of Selected Oil and Natural Gas Terms

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

“3-D seismic” means an advanced technology method of detecting accumulation of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

“Basin” means a large depression on the earth’s surface in which sediments accumulate.

“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, in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of NGLs also differs significantly in price from a barrel of oil.

“Boe/d” means Boe per day.

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

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

“Dry hole” means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

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

“GAAP” (generally accepted accounting principles) is a collection of commonly-followed accounting rules and standards for financial reporting.

“Gross acres or gross wells” mean the total acres or wells, as the case may be, in which we have working interest.

“Horizontal drilling” means a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“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.

“Net acres or net wells” means gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

“NGL” or “NGLs” means natural gas liquids, i.e. hydrocarbons removed as a liquid, such as ethane, propane and butane, which are expressed in barrels.

“NYMEX” means New York Mercantile Exchange.

“Oil” includes crude oil and condensate.

“Productive well” means a well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

“Proved area” means the part of a property to which proved reserves have been specifically attributed.

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

“Proved oil and natural gas reserves” means the estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

“Proved undeveloped reserves” means proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

“Realized price” means the cash market price less all expected quality, transportation and demand adjustments.

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

“Reserve” means that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“Resources” means quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

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

“Spacing” means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 75 acre well-spacing) and is often established by regulatory agencies.

“Standardized measure” means the present value of estimated future after tax net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

“Trend” means a geographic area with hydrocarbon potential.

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

“Unproved properties” means properties with no proved reserves.

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

“Wellbore” means the hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

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

“Workover” means operations on a producing well to restore or increase production.

“WTI” means the West Texas Intermediate spot price.

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., a Delaware corporation, and its subsidiaries, as a common entity, and "Yuma California" prior to our reincorporation from California to Delaware in October 2016. 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., a Delaware corporation, is an independent Houston-based exploration and production company focused on acquiring, developing and exploring for conventional and unconventional oil and natural gas resources. Historically, our operations have focused on onshore properties located in central and southern Louisiana and southeastern Texas where we have a long history of drilling, developing and producing both oil and natural gas assets. More recently, we have begun acquiring acreage in an extension of the San Andres formation in Yoakum County, Texas, with plans to explore and develop additional oil and natural gas assets in the Permian Basin of West Texas. Finally, we have operated positions in Kern County, California, and non-operated positions in the East Texas Woodbine and the Bakken Shale in North Dakota. Our common stock is listed on the NYSE American under the trading symbol "YUMA."

Recent Developments

Common Stock Offering

In September and October 2017, we completed a public offering of 10,100,000 shares of common stock (including 500,000 shares purchased pursuant to the underwriter's overallotment option), at a public offering price of $1.00 per share. We received net proceeds from this offering of approximately $8.7 million, after deducting underwriters' fees and offering expenses of $1.4 million.

Entry into the Permian Basin

In 2017, we entered the Permian Basin through a joint venture with two privately held energy companies and established an Area of Mutual Interest ("AMI") covering approximately 33,280 acres in Yoakum County, Texas, located in the Northwest Shelf of the Permian Basin. The primary target within the AMI is the San Andres formation, which has been one of the largest producing formations in Texas to date. As of March 1, 2018, we held a 62.5% working interest in approximately 4,558 gross acres (2,849 net acres) within the AMI and intend to apply horizontal drilling technology to the San Andres formation. This activity is commonly referred to as the San Andres Horizontal Oil Play, and in certain areas, referred to as a Residual Oil Zone ("ROZ") Play due to the presence of residual oil zone fairways with substantial recoverable hydrocarbon resources in place. We are the operator of the joint venture and intend to acquire additional leases offsetting existing acreage. In December 2017, we sold a 12.5% working interest in ten sections of the project on a promoted basis and sold an additional 12.5% working interest in the same ten sections under the same terms in January 2018. On November 8, 2017, we spudded a salt water disposal well, the Jameson SWD #1, and completed the well on December 8, 2017. The rig was then moved to our State 320 #1H horizontal San Andres well, which we spudded on December 13, 2017. The State 320 #1H well reached total depth on January 2, 2018, and was subsequently completed and fraced, with the last stage being completed on February 15, 2018. After the frac was completed, we installed an electrical submersible pump ("ESP") and placed the well on production on March 1, 2018. The well is currently in the early stages of recovering stimulation fluids and dewatering the near wellbore area.

Sale of Certain Non-Core Oil and Gas Properties

On May 22, 2017 and effective as of January 1, 2017, we sold certain oil and natural gas properties for $5.5 million located in Brazos County, Texas known as the El Halcón property. Our El Halcón property consisted of an average working interest of approximately 8.5% (1,557 net acres) producing approximately 140 Boe/d net from 50 Eagle Ford wells and one Austin Chalk well.

Reincorporation Merger and Davis Merger

On October 26, 2016, Yuma Energy, Inc., a California corporation (“Yuma California”), merged with and into the Company resulting in our reincorporation from California to Delaware (the “Reincorporation Merger”). In connection with the Reincorporation Merger, Yuma California converted each outstanding share of its 9.25% Series A Cumulative Redeemable Preferred Stock (the “Yuma California Series A Preferred Stock”), into 35 shares of its common stock (the “Yuma California Common Stock”), and then each share of Yuma California Common Stock was exchanged for one-twentieth of one share of common stock of the Company (the “common stock”). Immediately after the Reincorporation Merger on October 26, 2016, a wholly owned subsidiary of the Company merged (the “Davis Merger”) with and into Davis Petroleum Acquisition Corp., a Delaware corporation (“Davis”), in exchange for approximately 7,455,000 shares of common stock and 1,754,179 shares of Series D Convertible preferred stock (the “Series D preferred stock”). The Series D preferred stock had an aggregate liquidation preference of approximately $19.4 million and a conversion rate of $11.0741176 per share at the closing of the Davis Merger, and will be paid dividends in the form of additional shares of Series D preferred stock at a rate of 7% per annum. As a result of the Davis Merger, the former holders of Davis common stock received approximately 61.1% of the then outstanding common stock of the Company and thus acquired voting control.

The Davis 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 value. Although the Company was the legal acquirer, Davis was the accounting acquirer. The historical financial statements are therefore those of Davis. Hence, the financial statements included in this report reflect (i) the historical results of Davis prior to the Davis Merger; (ii) the combined results of the Company following the Davis Merger; (iii) the acquired assets and liabilities of Davis at their historical cost; and (iv) the fair value of the Company’s assets and liabilities as of the closing of the Davis Merger.

Senior Credit Agreement

In connection with the closing of the Davis Merger on October 26, 2016, the Company and three of its subsidiaries, as the co-borrowers, entered into a credit agreement providing for a $75.0 million three-year senior secured revolving credit facility (the “Credit Agreement”) with Société Générale (“SocGen”), as administrative agent, SG Americas Securities, LLC, as lead arranger and bookrunner, and the Lenders signatory thereto (collectively with SocGen, the “Lender”).

The borrowing base of the credit facility was reaffirmed on September 8, 2017 at $40.5 million. The borrowing base is generally subject to redetermination on April 1st and October 1st of each year, as well as special redeterminations described in the Credit Agreement. The amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate (“LIBOR”) plus 3.00% to 4.00% or (b) the prime lending rate of SocGen plus 2.00% to 3.00%, depending on the amount borrowed under the credit facility and whether the loan is drawn in U.S. dollars or Euro dollars. The interest rate for the credit facility at December 31, 2017 was 5.07% for LIBOR-based debt and 7.00% for prime-based debt. Principal amounts outstanding under the credit facility are due and payable in full at maturity on October 26, 2019. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of our assets. Additional payments due under the Credit Agreement include paying a commitment fee to the Lender in respect of the unutilized commitments thereunder. The commitment rate is 0.50% per year of the unutilized portion of the borrowing base in effect from time to time. We are also required to pay customary letter of credit fees.

The Credit Agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, our ability to incur additional indebtedness, create liens on assets, make investments, enter into sale and leaseback transactions, pay dividends and distributions or repurchase our capital stock, engage in mergers or consolidations, sell certain assets, sell or discount any notes receivable or accounts receivable, and engage in certain transactions with affiliates.

In addition, the Credit Agreement requires us to maintain the following financial covenants: a current ratio of not less than 1.0 to 1.0 on the last day of each quarter, a ratio of total debt to earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses (“EBITDAX”) ratio of not greater than 3.5 to 1.0 for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding such date of determination, and a ratio of EBITDAX to interest expense of not less than 2.75 to 1.0 for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding such date of determination, and cash and cash equivalent investments together with borrowing availability under the Credit Agreement of at least $4.0 million. The Credit Agreement contains customary affirmative covenants and defines events of default for credit facilities of this type, including failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default, and a change of control. Upon the occurrence and continuance of an event of default, the Lender has the right to accelerate repayment of the loans and exercise its remedies with respect to the collateral. As of December 31, 2017, we were in compliance with the covenants under the Credit Agreement.

Preferred Stock

As of December 31, 2017, we had 1,904,391 shares of our Series D preferred stock outstanding with an aggregate liquidation preference of approximately $21.1 million and a conversion price of $6.5838109 per share. The conversion price was adjusted from $11.0741176 per share to $6.5838109 per share as a result of our common stock offering that closed in October 2017. As a result, if all of our outstanding shares of Series D preferred stock were converted into common stock, we would need to issue approximately 3.2 million shares of common stock. The Series D preferred stock is paid dividends in the form of additional shares of Series D preferred stock at a rate of 7% per annum.

Operating Outlook

Recognizing the volatility in oil and natural gas prices, we plan to continue a disciplined approach in 2018 by emphasizing liquidity and value, enhancing operational efficiencies, and managing 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

Due to the continued volatile commodity price environment and our belief that uncertainty remains with respect to commodity prices in 2018, we expect our capital spending plans to be limited primarily to within our cash flow. In addition, we may slow or accelerate the development of our properties to more closely match our projected cash flows. We will be focused on lower risk and lower cost opportunities that are expected to have higher returns to maintain our production and cash flow. In addition, we intend to capture new opportunities in the Permian Basin that will build on existing inventory, as well as the Gulf Coast basins where we have considerable history and experience.

The key elements of our business strategy are:

➢ seek merger, acquisition, and joint venture opportunities to increase our liquidity, as well as reduce our G&A on a per Boe basis;

➢ transition existing inventory of non-producing and undeveloped 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 and developing:

- unconventional oil and natural gas 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 Permian Basin and Gulf Coast regions* . We believe our extensive understanding of the geology and experience in interpreting well control, core and 3-D seismic data in these areas provides us with a competitive advantage in exploring and developing projects in the Permian Basin and Gulf Coast regions. We have cultivated amicable and mutually beneficial relationships with acreage owners in these regions 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 an area within the Permian Basin of west Texas, the Gulf Coast, southeastern Texas, the Bakken/Three Forks shale in North Dakota, along with shallow oil fields in central California.

- *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 Louisiana and Texas Gulf Coast, the Permian Basin and southeast Texas, and most of the other oil and natural gas producing regions of the United States. Our exploration team has substantial expertise in the design, acquisition, processing and interpretation of 3-D seismic surveys, our experienced operations team allows for efficient turnaround from project identification, to drilling, to production, and our engineering and geoscience teams have considerable experience evaluating both conventional and unconventional opportunities in existing and prospective trends.

- *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.

Description of Major Properties

We are the operator of properties containing approximately 63.5% of our proved oil and natural gas reserves as of December 31, 2017. 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 and investments 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.

Permian Basin

In 2017, we entered the Permian Basin through a joint venture with two privately held energy companies and established an AMI covering approximately 33,280 acres in Yoakum County, Texas, located in the Northwest Shelf of the Permian Basin. The primary target within the AMI is the San Andres formation, which has been one of the largest producing formations in Texas to date. As of March 1, 2018, we held a 62.5% working interest in approximately 4,558 gross acres (2,849 net acres) within the AMI and intend to apply horizontal drilling technology to the San Andres formation. This activity is commonly referred to as the San Andres Horizontal Oil Play, and in certain areas, referred to as a Residual Oil Zone ("ROZ") Play due to the presence of residual oil zone fairways with substantial recoverable hydrocarbon resources in place. We are the operator of the joint venture and intend to acquire additional leases offsetting existing acreage. In December 2017, we sold a 12.5% working interest in ten sections of the project on a promoted basis and sold an additional 12.5% working interest in the same ten sections under the same terms in January 2018. On November 8, 2017, we spudded a salt water disposal well, the Jameson SWD #1, and completed the well on December 8, 2017. The rig was then moved to our State 320 #1H horizontal San Andres well, which we spudded on December 13, 2017. The State 320 #1H well reached total depth on January 2, 2018, and was subsequently completed and fraced, with the last stage being completed on February 15, 2018. After the frac was completed, we installed an ESP and placed the well on production on March 1, 2018. The well is currently in the early stages of recovering the stimulation fluids and dewatering the near wellbore area.

South Louisiana

We have operated and non-operated assets in many of the prolific oil and natural gas producing parishes of south Louisiana including Cameron, LaFourche, Livingston, St. Helena, St. Bernard, and Vermilion parishes. As of December 31, 2017, we had working interests in nine fields in south Louisiana, of which we operate eight with an average operated working interest of 62.7%. The acreage associated with these leasehold positions is comprised of 19,668 gross acres and 3,862 net acres. The associated assets produce from a variety of conventional formations with oil, natural gas, and natural gas liquids from depths of approximately 5,500 feet to almost 19,000 feet. The formations include the Lower Miocene, CibCarst, Dibert, Wilcox, Marg Tex, Het 1A, Tuscaloosa, Miocene Siphonina, and Lower Planulina Cris R sands. The collective net production from this area averaged approximately 489 Bbl/d of oil, 8.0 MMcf/d of natural gas and 229 Bbl/d of natural gas liquids during the year ended December 31, 2017. Our inventory of future development opportunities includes proved, probable and possible reserves and prospective resources consisting of behind pipe recompletions, artificial lift installations, workovers, sidetracks of existing wells and new well drilling opportunities.

Our two largest fields in south Louisiana, based on estimated proved reserve value, are described below.

Lac Blanc Field, Vermilion Parish, Louisiana – We are the operator of the Lac Blanc Field where we have an average working interest of 81.3%. The field is comprised of 1,744 gross acres and 1,090 net acres where two wells, the SL 18090 #1 and #2, are producing from the Miocene Siphonina D-1 sand (18,700 feet sand). The net production from the field averaged approximately 69 Bbl/d of oil, 3.0 MMcf/d of natural gas and 175 Bbl/d of natural gas liquids during the year ended December 31, 2017.

Bayou Hebert Field, Vermilion Parish, Louisiana – We have a 12.5% non-operated working interest in the Bayou Hebert Field, which is comprised of approximately 1,600 gross acres and 200 net acres with three wells completed in the Lower Planulina Cris R sands. One of the three wells is currently shut-in. The net production from the field averaged approximately 70 Bbl/d of oil, 3.4 MMcf/d of natural gas and 118 Bbl/d of natural gas liquids during the year ended December 31, 2017. Future development opportunities include behind pipe recompletions and sidetracking an existing wellbore for proved and non-proved reserves.

Southeast Texas

We have operated and non-operated assets in southeast Texas containing both conventional and unconventional properties located in Jefferson and Madison counties. As of December 31, 2017, we had working interests in two fields, one of which we are the operator, with a working interest of 47.4%. The average working interest in the non-operated field was approximately 23.0%. The acreage associated with these leasehold positions consist of 25,724 gross acres and 1,248 net acres. The unconventional assets are developed primarily with horizontal wells in the Eagle Ford and tight Woodbine sands producing oil, natural gas, and natural gas liquids from depths of approximately 8,000 feet to 9,000 feet. Typical development wells are drilled horizontally with lateral sections ranging from approximately 4,500 feet to 7,500 feet in length where multi-stage fracturing technology is employed. The collective net production from this area averaged approximately 85 Bbl/d of oil, 372 Mcf/d of natural gas and 60 Bbl/d of natural gas liquids during the year ended December 31, 2017, which includes production from our El Halcón property prior to its sale in May 2017. Future development opportunities include the drilling of proved and non-proved reserves, the development of which will be influenced largely by future oil and natural gas commodities prices.

California

We have assets in Kern County, California. As of December 31, 2017, we have a 100% working interest in five conventional fields with a leasehold position comprised of 1,192 gross acres inclusive of 263 fee or minerals only acres. These properties produce oil from a variety of conventional formations including the Pliocene, Miocene, Oligocene, and Eocene from depths ranging from approximately 800 feet to 6,300 feet and are characterized by long-life shallow decline production profiles. For the year ended December 31, 2017, net production from our California assets averaged approximately 95 Bbls/d of oil. Future development opportunities include behind pipe recompletions, artificial lift installations, and new well drilling opportunities of proved and non-proved reserves.

North Dakota

We have non-operated working interests in the Bakken Play in McKenzie County, North Dakota. As of December 31, 2017, we had an approximate 4.7% average working interest in two fields that together include 7,680 gross acres and 362 net acres. Oil, natural gas, and natural gas liquids are produced from depths of approximately 8,000 feet from wells drilled horizontally with lateral lengths ranging from approximately 5,000 feet to 10,000 feet and completed with multi-stage fracturing technology. For the year ended December 31, 2017, net production from these assets averaged 16 Bbl/d of oil, 9 Mcf/d of natural gas and 2 Bbl/d of natural gas liquids. Future development opportunities include the drilling of non-proved reserves, 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 23 – 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 2017 other than to the SEC and the Department of Energy.

Estimated Proved Reserves

The table below summarizes our estimated proved reserves at December 31, 2017 based on reports prepared by NSAI. In preparing these reports, NSAI evaluated 100% of our properties at December 31, 2017. For more information regarding our independent reserve engineers, please see Independent Reserve Engineers below. The information in the following table does not give any effect to or reflect our commodity derivatives.

	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)	Present Value Discounted at 10% ($ in thousands)(2)
Proved developed (3)					
Lac Blanc Field (4)	330	712	12,132	3,065	$ 23,895
Bayou Hebert Field (4)	142	239	6,871	1,526	19,490
Other	1,291	58	2,128	1,704	20,643
Total proved developed	1,763	1,009	21,131	6,295	64,028
Proved undeveloped (3)					
Lac Blanc Field (4)	-	-	-	-	-
Bayou Hebert Field (4)	-	-	-	-	-
Other	599	285	2,465	1,295	8,875
Total proved undeveloped	599	285	2,465	1,295	8,875
Total proved (3)	2,362	1,294	23,596	7,590	$ 72,903

(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 23 – 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, 2017:

Present value of estimated future net revenues (PV10)	$ 72,903
Future income taxes discounted at 10%	-
Standardized measure of discounted future net cash flows	$ 72,903

(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 $51.34 per Bbl (WTI) and $2.98 per MMBtu (HH), for the year ended December 31, 2017. Adjustments were made for location and grade.

(4) Our Lac Blanc Field and Bayou Hebert Field were our only fields that each contained 15% or more of our estimated proved reserves as of December 31, 2017.

Proved Undeveloped Reserves

At December 31, 2017, our estimated proved undeveloped (“PUD”) reserves were approximately 1,295 MBoe. The following table details the changes in PUD reserves for the year ended December 31, 2017 (in MBoe):

Beginning proved undeveloped reserves at January 1, 2017	1,404
Undeveloped reserves transferred to developed	-
Purchases of minerals-in-place	-
Sales of minerals-in-place	(408)
Extensions and discoveries	176
Production	-
Revisions	123
Proved undeveloped reserves at December 31, 2017	1,295

From January 1, 2017 to December 31, 2017, our PUD reserves decreased 109 MBoe, or 8%, from 1,404 MBoe to 1,295 MBoe, primarily due to the sale of minerals-in-place in Santa Barbara County, California of 408 MBoe. This decrease was partially offset by 176 MBoe added through extensions of existing discoveries in Kern County, California and upward revisions of 123 MBoe due to increased prices. As of December 31, 2017, 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 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 31 years of industry experience, with 21 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 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 President and 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, 2017 and 2016, the average sales price per unit sold and the average production cost per unit are presented below.

	Years Ended December 31, 2017	Years Ended December 31, 2016
Production volumes:		
Crude oil and condensate (Bbls)	250,343	172,003
Natural gas (Mcf)	3,085,613	2,326,400
Natural gas liquids (Bbls)	131,155	104,689
Total (Boe) (1)	895,767	664,425
Average prices realized:		
Crude oil and condensate (per Bbl)	$ 50.32	$ 42.21
Natural gas (per Mcf)	$ 3.05	$ 2.45
Natural gas liquids (per Bbl)	$ 26.08	$ 17.33
Production cost per Boe (2)	$ 9.80	$ 5.98

(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 $2,262,702 and $1,588,798 in fiscal years 2017 and 2016, respectively.

Our interests in Lac Blanc Field and Bayou Hebert Field represented 40.0% and 20.1%, respectively, of our total proved reserves as of December 31, 2017. Our interests in Lac Blanc Field and Bayou Hebert Field represented 31.1% and 21.7%, respectively, of our total proved reserves as of December 31, 2016. No other single field accounted for 15% or more of our proved reserves as of December 31, 2017 and 2016.

The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2017 and 2016, the average sales price per unit sold and the average production cost per unit for our Lac Blanc Field are presented below.

Lac Blanc Field	Years Ended December 31, 2017	Years Ended December 31, 2016
Production volumes:		
Crude oil and condensate (Bbls)	25,070	22,111
Natural gas (Mcf)	1,101,824	1,069,325
Natural gas liquids (Bbls)	63,841	56,005
Total (Boe) (1)	272,548	256,337
Average prices realized:		
Crude oil and condensate (per Bbl)	$ 50.86	$ 41.46
Natural gas (per Mcf)	$ 3.22	$ 2.43
Natural gas liquids (per Bbl)	$ 27.76	$ 18.75
Production cost per Boe (2)	$ 6.63	$ 6.37

(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 $326,526 and $412,372 in fiscal years 2017 and 2016, respectively.

The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2017 and 2016, the average sales price per unit sold and the average production cost per unit for our Bayou Hebert Field are presented below.

Bayou Hebert Field	Years Ended December 31, 2017		2016	
Production volumes:				
Crude oil and condensate (Bbls)		25,479		4,401
Natural gas (Mcf)		1,236,615		177,756
Natural gas liquids (Bbls)		43,196		5,553
Total (Boe) (1)		274,778		39,580
Average prices realized:				
Crude oil and condensate (per Bbl)	$	52.80	$	47.41
Natural gas (per Mcf)	$	3.10	$	3.01
Natural gas liquids (per Bbl)	$	27.85	$	22.72
Production cost per Boe (2)	$	4.51	$	6.48

(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 $289,857 and $308,338 in fiscal years 2017 and 2016, respectively.

Gross and Net Productive Wells

As of December 31, 2017, 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
84	54	31	6	115	60

(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 8 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, 2017, 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	19,028	3,344	640	518	19,668	3,862
North Dakota	7,680	362	-	-	7,680	362
Texas	26,584	1,225	8,237	3,262	34,821	4,487
Oklahoma	2,000	79	-	-	2,000	79
California	1,192	1,192	-	-	1,192	1,192
Total	56,484	6,202	8,877	3,780	65,361	9,982

As of December 31, 2017, we had leases representing 1,996 net acres (none of which were in the Lac Blanc or Bayou Herbert Fields) expiring in 2018; 607 net acres (none of which were in the Lac Blanc or Bayou Herbert Fields) expiring in 2019; and 1,083 net acres expiring in 2020 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 2018 and beyond.

Exploratory Wells and Development Wells

Set forth below for the years ended December 31, 2017 and 2016 is information concerning our drilling activity during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells Drilled
Year	**Productive**	**Dry**	**Productive**	**Dry**	
2017	-	0.5	-	-	0.5
2016	-	-	1.0	-	1.0

Present Activities

At April 2, 2018, 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 WTI and adjusted to LLS or HLS. 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 commodity derivative activities as discussed below in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Commodity derivative Activities."

Competition

The domestic oil and natural gas business is intensely competitive in the exploration for and acquisition of leasehold interests, reserves and in the producing and marketing of oil and natural gas production. Our competitors include national oil companies, major oil and natural gas companies, independent oil and natural gas companies, drilling partnership programs, individual producers, natural gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers. Many of our competitors are large, well-established companies. They likely are able to pay more for seismic information and lease rights on oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate oil and gas related transactions in a highly competitive environment.

Other Business Matters

Major Customers

During the years ended December 31, 2017 and 2016, sales to five customers accounted for approximately 79% and sales to five customers accounted for approximately 78%, respectively, of the Company's total revenues.

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 oil and natural gas 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, development and production involve 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, acquire or produce 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 our 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 do 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 and cash flows. For further discussion of these risks see Item 1A. “Risk Factors” of this report.

Title to Properties

We believe that the title to our oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and natural gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of our oil and natural gas properties. Our oil and natural gas properties are typically subject, in one degree or another, 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, joint development agreements, farmout agreements, participation agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under various 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 other 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 quantity and value of our reserves. We believe that the burdens and obligations affecting our oil and natural gas properties are common in our industry with respect to the types of properties we own.

Operational Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory and regulatory provisions affecting drilling, completion, and production activities, 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 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, while some states allow the forced pooling or integration of land and leases to facilitate development, other states including Texas, where we operate, rely primarily or exclusively on voluntary pooling of land and leases. Accordingly, it may be difficult for us to form spacing units and therefore difficult to develop a project if we own or control 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, local authorities have imposed moratoria or other restrictions on exploration, development and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration, development 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.

Regulation of Transportation of Natural Gas

The transportation and sale, or resale, of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission (“FERC”) under the Natural Gas Act of 1938 (“NGA”), the Natural Gas Policy Act of 1978 (“NGPA”) and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Sales of Oil, Natural Gas and Natural Gas Liquids

The prices at which we sell oil, natural gas and natural gas liquids are not currently subject to federal regulation and, for the most part, are not subject to state regulation. FERC, however, regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. Similarly, the price we receive from the sale of oil and natural gas liquids is affected by the cost of transporting those products to market. FERC regulates the transportation of oil and liquids on interstate pipelines under the provision of the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations issued under those statutes. Intrastate transportation of oil, natural gas liquids, and other products, is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. In addition, while sales by producers of natural gas and all sales of crude oil, condensate, and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Environmental Regulations

Our operations are also 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 U. S. Environmental Protection Agency (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 govern the permitting, construction and operation of a well or production related 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.

Beyond existing requirements, new programs and changes in existing programs may affect our business, including 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 of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct on certain categories 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 site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances found at the site. Under CERCLA, these potentially responsible persons may be subject to strict, 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 certain 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. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are not presently aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

The Resource Conservation and Recovery Act of 1976 (“RCRA”), and comparable state statutes, regulate the generation, treatment, storage, transportation, disposal and clean-up of hazardous and solid (non-hazardous) wastes. With the approval of the EPA, the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA’s solid (non-hazardous) waste provisions. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain oil and natural gas exploration and production wastes as “hazardous wastes,” which would make such wastes subject to much more stringent handling, disposal and clean-up requirements. For example, in response to a lawsuit filed in the U.S. District Court for the District of Columbia by several non-governmental environmental groups against the EPA for the agency’s failure to timely assess its RCRA Subtitle D criteria regulations for oil and natural gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our, as well as the oil and natural gas E&P industry’s, costs to manage and dispose of generated wastes, which could have a material adverse effect on the industry as well as on our business.

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

The federal Clean Water Act and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including jurisdictional wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. In September 2015, a new EPA and U.S. Army Corps of Engineers rule defining the scope of federal jurisdiction over wetlands and other waters became effective. To the extent the rule expands the range of properties subject to the Clean Water Act’s jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been stayed pending resolution of the court challenge. In addition, following the issuance of a presidential executive order to review the rule, on July 27, 2017, the EPA proposed to repeal the rule and also separately announced its intent to conduct a substantive re-evaluation of the definition of “waters of the United States” in a future rulemaking. As a result, future implementation of the rule is uncertain at this time.

The process for obtaining permits has the potential to delay our operations. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. The Clean Water Act and analogous state laws provide for administrative, civil and criminal penalties for unauthorized discharges and, together with the Oil Pollution Act of 1990 (“OPA”), impose rigorous requirements for spill prevention and response planning, as well as substantial potential liability for the costs of removal, remediation, and damages in connection with any unauthorized discharges.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program, 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. In particular, the well completion technique known as hydraulic fracturing, which is used to stimulate production of oil and natural gas, has come under increased scrutiny by the environmental community, and many local, state and federal regulators. 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 depths to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

The SDWA regulates the underground injection of substances through the UIC program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process.

Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the fracturing process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells.

In addition, the EPA previously announced plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism, regulatory, voluntary, or a combination of both, to collect data on hydraulic fracturing chemical substances and mixtures. Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment ("CWT") facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

In addition, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. Also, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and natural gas operations on federal and Indian lands. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. Also, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of the 2016 methane rule until January 17, 2019. Further legal challenges are expected. At this time, it is uncertain when, or if, the rules will be implemented or modified, and what impact they would have on our operations.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Some states and local jurisdictions in which we operate or hold oil and natural gas interests have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. If new or more stringent state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Air Emissions

The federal Clean Air Act and comparable state laws restrict 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 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.

In 2012 and 2016, the EPA issued New Source Performance Standards to regulate emissions of sources of volatile organic compounds (“VOCs”), sulfur dioxide, air toxics and methane from various oil and natural gas exploration, production, processing and transportation facilities. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. We cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

In October 2015, the EPA announced that it was lowering the primary national ambient air quality standards ("NAAQS") for ozone from 75 parts per billion to 70 parts per billion. The EPA did not meet an October 2017 deadline for designating non-attainment areas but has indicated that it continues to work with states to make the required designations. If implemented in the future, the changes will take place over several years; however, the new standard could result in a significant expansion of ozone non-attainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone non-attainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs"), present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. In May 2010, the EPA adopted regulations establishing new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. On June 23, 2014, in *Utility Air Regulatory Group v. EPA*, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On August 26, 2016, the EPA proposed changes needed to bring EPA's air permitting regulations in line with the Supreme Court's decision on GHG permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions.

In December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. Currently, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

The National Environmental Policy Act

Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act ("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. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Threatened and endangered species, migratory birds and natural resources

Various federal and state 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 ("ESA"), the Migratory Bird Treaty Act and the Clean Water Act. The U.S. Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened 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 may result. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds, we believe that we are in substantial compliance with the ESA and the Migratory Bird Treaty Act, and we are not aware of any proposed ESA listings that will materially affect our operations. The federal government in the past has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce our oil and natural gas reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

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, including, but not limited to, the federal Emergency Planning & Community Right-to-Know Act, govern record keeping and reporting of the use and release of hazardous substances and may require that information be provided to state and local government authorities, as well as the public.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes that regulate the protection of the health and safety of workers. In addition, OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

State Regulation

Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure our stockholders that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2017, nor do we anticipate that such expenditures will be material in 2018.

Employees and Principal Office

As of December 31, 2017, we had 31 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.

Executive Officers of the Company

The following table sets forth the names and ages of all of our executive officers, the positions and offices 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	October 2016	68	Director and Chief Executive Officer
James J. Jacobs	October 2016	40	Chief Financial Officer, Treasurer and Corporate Secretary
Paul D. McKinney	October 2016	59	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 a member of the Board of Directors since the closing of the Davis Merger on October 26, 2016. He was the Chief Executive Officer and Chairman of the Board of Directors of Yuma California from September 10, 2014 and also our President since October 10, 2014 through October 26, 2016. He was the Chief Executive Officer and Chairman of the Board of Directors of The Yuma Companies, Inc. ("Yuma Co.") and its predecessor since 1983. He was also the founder of Yuma Co. He has 40 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 the closing of the Davis Merger on October 26, 2016. He was the Chief Financial Officer, Treasurer and Corporate Secretary of Yuma California from December 2015 through October 26, 2016. He served as Vice President – Corporate and Business Development of Yuma California immediately prior to his appointment as Chief Financial Officer in December 2015 and has been with us since 2013. He has 16 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 the closing of the Davis Merger on October 26, 2016. He was the Executive Vice President and Chief Operating Officer of Yuma California from October 2014 through October 26, 2016. Mr. McKinney served as a petroleum engineering consultant for Yuma California's predecessor from June 2014 to September 2014 and for Yuma California 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 currently serves on the Board of Directors for Pro-Ject Holdings, LLC, a private oil field chemical services company. 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 various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in this report under "Cautionary Statement Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

If we are not able to access additional capital in significant amounts, we may not be able to continue to develop our current prospects and properties, or we may forfeit our interest in certain prospects and we may not be able to continue to operate our business.

We need significant capital to continue to operate our properties and continue operations. In the near term, we intend to finance our capital expenditures with cash flow from operations, borrowings under our revolving credit facility, and future issuance of debt and/or equity securities. Our cash flow from operations and access to capital is subject to a number of variables, including, among others:

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;
- the prices at which we sell our production;
- the costs of developing and producing our oil and natural gas reserves;
- our ability to acquire, locate and produce new reserves;
- our borrowing base and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

Our operations and other capital resources may not provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2018 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include refinancing existing debt, joint venture partnerships, production payment financings, sales of non-core property assets, or offerings of debt or equity securities. We may not be able to obtain any form of financing on terms favorable, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings. The occurrence of such events may prevent us from continuing to operate our business and our common stock and preferred stock may not have any value.

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 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. For the year ended December 31, 2017, we had outstanding borrowing of $27.7 million under our credit facility. As of December 31, 2017, our total borrowing base was $40.5 million with $12.8 million of undrawn borrowing base. Since significant amounts of capital are required for companies to participate in the business of exploration for and development of oil and natural gas resources, we are dependent on improving our cash flow and revenue, as well as receipt of additional working capital, to fund continued development and implementation of our business plan. Adverse developments in our business or general economic conditions may require us to raise additional financing at prices or on terms that are disadvantageous to existing stockholders. We may not be able to obtain additional capital at all and may be forced to curtail or cease our operations. We will continue to rely on equity or debt financing and the sale of working interests to finance operations until such time, if ever, that we generate sustained positive cash flow. The inability to obtain necessary financing will likely adversely impact our ability to develop our properties and to expand our business operations.

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. Reductions in our borrowing base under our credit facility could also arise from several factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in oil, natural gas and natural gas liquid reserves due to engineering updates, or changes in engineering applications;
- increased operating and/or capital costs;
- the lenders’ inability to agree to an adequate borrowing base; or
- adverse changes in the lenders’ practices (including required regulatory changes) regarding estimation of reserves.

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 set our current borrowing base at $40.5 million. Prices of crude oil below $50.00 per Bbl 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 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. Any 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 remains 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, during the period from January 1, 2014 through December 31, 2017, the WTI futures price for oil declined from a high of $107.26 per Bbl on June 20, 2014 to $26.21 per Bbl on February 11, 2016, and subsequently increased to reach a high of $60.01 per Bbl in December 2017; and the Henry Hub futures price for natural gas has declined from a high of $6.15 per MMBtu on February 19, 2014 to a low of $1.64 per MMBtu on March 3, 2016, and subsequently increased to reach a high of $3.69 per MMBtu in December 2017. 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 oil and natural gas producing countries to agree upon and determine 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 overall product demand;
- the growth of consumer product demand in emerging markets, such as China and India;
- 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 resultant 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 significant 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;
- forcing reductions in the financial carrying value of our oil and natural gas properties due to recognizing impairments of proved properties, unproved properties and exploration assets;
- reducing the standardized measure of discounted future net cash flows relating to our 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.

As a result of low prices for oil, natural gas and natural gas liquids, we have taken and may be required to take significant future write-downs of the financial carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and 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 have been required to, and may be required to significantly write-down the financial carrying value of our oil and natural gas properties, which constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are recorded.

A write-down could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved oil and natural gas reserves, if operating costs or development costs increase over prior estimates, or if our drilling and workover program is unsuccessful.

The capitalized costs of our oil and natural gas properties subject to amortization, net of accumulated 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 unproved properties not subject to amortization. If the capitalized cost of these proved properties subject to amortization exceeds these estimated future net cash flows, we would be required to record impairment charges to reduce the capitalized costs of our oil and natural gas properties. These types of charges will reduce our earnings and stockholders' equity and could adversely affect our stock price. Unproved properties not subject to amortization are evaluated quarterly, and this review may result in these properties being moved into our oil and gas properties subject to amortization.

We periodically assess our properties for impairment based on future estimates of proved and non-proved reserves, oil and natural gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Once incurred, an impairment charge cannot be reversed at a later date even if price increases of oil and/or natural gas occur and in the event of increases in the quantity of our estimated proved reserves.

If oil, natural gas and natural gas liquids prices fall below current levels for an extended period of time and all other factors remain equal, we may incur impairment charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are recorded. See Note 5. Asset Impairments and Note 6. Property, Plant, and Equipment, Net in the Notes to the Consolidated Financial Statements included in this report for additional information.

We have historically incurred losses and may not achieve profitability in the future.

We have incurred losses from operations during our history in the oil and natural gas business. We had an accumulated deficit of approximately $19.2 million as of December 31, 2017. Our ability to be profitable in the future will depend on successfully addressing our near-term capital needs and implementing our acquisition, development and production activities, all of which are subject to many risks beyond our control. Even if we become profitable on an annual basis, our profitability may not be sustainable or increase on a periodic basis.

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 oil, natural gas or natural gas liquids 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 natural gas liquids, 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 would likely adversely affect our cash flow.

Our oil, natural gas and natural gas liquids are sold in a limited number of geographic markets so an oversupply in any of those areas could have a material negative effect on the price we receive.

Our oil, natural gas and natural gas liquids are sold in a limited number of geographic markets and each has a fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with oil, natural gas and/or natural gas liquids, it could have a material negative effect on the prices we receive for our products and therefore an adverse effect on our financial condition and results of operations. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut-in or reduction of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas from the United States.

Commodity derivative 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 and natural gas production, we have entered into oil and natural gas price commodity derivative arrangements with respect to a portion of our anticipated production and we may enter into additional commodity derivative 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 commodity derivative. 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 commodity derivative agreements fail to perform under the contracts.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (the "CFTC"), the SEC, and federal regulators of financial institutions adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act.

The CFTC has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin, clearing and trade execution; 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 commodity derivative transactions are expected to be made exempt from these limits. Also, it is possible that under recently adopted margin rules, some 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.

We may not be able to drill wells on a substantial portion of our leasehold 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. Deterioration in commodities prices may also make drilling certain acreage uneconomic. Our actual drilling activities and future drilling budget will depend on prior 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 business, financial condition and results of operations.

Approximately 37.8% 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.

As of December 31, 2017, approximately 37.8% of our net leasehold acreage was 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. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income, are highly dependent on successfully developing our undeveloped leasehold acreage. We may also lose the right to claim certain proved undeveloped reserves in our engineering and financial reports if we cannot demonstrate the probability of developing those reserves within prescribed time frames, usually within five years. Further, to the extent we determine that it is not economic to develop particular undeveloped acreage; we may intentionally allow leases to expire.

Unless we replace our reserves with new reserves and develop those reserves, our production and estimated reserves will decline, which may adversely affect our financial condition, results of operations and/or future cash flows.

Producing oil and natural gas reservoirs are generally characterized by declining production rates that may vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well, particularly horizontal wells. Estimates of the decline rate of an oil or natural gas well are inherently imprecise and may be 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. Unless we conduct successful ongoing acquisition and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Thus, our estimated future oil and natural gas reserves and production and, therefore, our cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting our current reserves 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 flows and the value of our reserves will decrease, adversely affecting our business, financial condition and results of operations.

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

This report contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by SEC regulations 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 and requires significant decisions, complex analyses and assumptions in evaluating available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Our 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 will likely materially affect the estimated quantities and the estimated value of our reserves. In addition, we may later adjust estimates of proved reserves to reflect production history, results of exploration and development activities, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

Quantities of estimated proved reserves are based on economic conditions in existence during the period of assessment. Changes to oil, natural gas and natural gas liquids prices in the markets for these commodities may shorten the economic lives of certain fields because it may become uneconomical to produce all recoverable reserves in such fields, which may reduce proved reserves estimates.

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future estimated cash flows of those reserves, may also trigger impairment losses on certain properties, which may result in non-cash charges to earnings. See Note 6 – Property, Plant, and Equipment, Net in the Notes to the Consolidated Financial Statements included in this report.

At December 31, 2017, approximately 17.1% 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, natural gas and natural gas liquids 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 estimated proved reserves may 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 estimated proved reserves set forth in this report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2017 and 2016, 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 arithmetic 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 incurring expenses related to developing and producing 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 our business or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for statutory 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 estimates included in this report which could have a material effect on the value of our estimated reserves.

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 issues 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 infrastructure 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.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oilfield 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.

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

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our leaseholds. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

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

In some cases, we operate but 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 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 success and timing of our drilling, development and production activities on such properties operated by third-parties therefore depends upon a number of factors, including:

- timing and amount of capital expenditures;
- the operator’s expertise and financial resources;
- the rate of production of reserves, if any;
- approval of other participants in drilling wells; and
- selection of technology.

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. As a result, our ability to exercise influence over the operations of some of our current or future properties is and may be limited.

Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

We design and generate in-house 3-D seismic survey programs on many of our projects. We may use seismic studies to assist with assessing prospective drilling opportunities on current properties, as well as on properties that we may acquire. Such seismic studies are merely an interpretive tool and do not necessarily guarantee that hydrocarbons are present or if present will produce in economic quantities. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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.

In assessing potential acquisitions, we consider information available in the public domain and information provided by the seller. In the event publicly available data is limited, then, by necessity, we may rely to a large extent on information that may only be available from the seller, particularly with respect to drilling and completion costs and practices, geological, geophysical and petrophysical data, detailed production data on existing wells, and other technical and cost data not available in the public domain. Accordingly, the review and evaluation of businesses or properties to be acquired may not uncover all existing or relevant data, obligations or actual or contingent liabilities that could adversely impact any business or property to be acquired and, hence, could adversely affect us as a result of the acquisition. These issues may be material and could include, among other things, unexpected environmental liabilities, title defects, unpaid royalties, taxes or other liabilities. If we acquire properties on an “as-is” basis, we may have limited or no remedies against the seller with respect to these types of problems.

The success of any acquisition that we complete will depend on a variety of factors, including our ability to accurately assess the reserves associated with the acquired properties, assumptions related to future oil and natural gas prices and operating costs, potential environmental and other liabilities and other factors. These assessments are often inexact and subjective. As a result, we may not recover the purchase price of a property from the sale of production from the property or recognize an acceptable return from such sales or operations.

Our ability to achieve the benefits that we expect from an acquisition will also depend on our ability to efficiently integrate the acquired operations. Management may be required to dedicate significant time and effort to the integration process, which could divert its attention from other business opportunities and concerns. The challenges involved in the integration process may include retaining key employees and maintaining employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding acquired properties.

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 and water 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. 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 results of operations and financial condition.

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

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or in the future plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the federal 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 completed a study finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. 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 March 2015 final rule that requires public disclosure of chemicals used in hydraulic fracturing, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. In June 2016, a federal district court judge in Wyoming struck down the final rule, finding that the BLM lacked congressional authority to promulgate the rule. The BLM appealed that ruling. However, in July 2017, the BLM initiated a rulemaking to rescind the final rule and reinstate the regulations that existed immediately before the published effective date of the rule. In light of the BLM's proposed rulemaking, in September 2017, the U.S. Court of Appeals for the Tenth Circuit dismissed the appeal and remanded with directions to vacate the lower court's opinion, leaving the final rule in place. On December 29, 2017, the BLM published a final rule rescinding the March 2015 final rule. Further, legislation to amend the SDWA to repeal the exemption for hydraulic fracturing (except when diesel fuels are used) from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of Congress. Several states and local jurisdictions in which we operate also have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids.

More recently, federal and state governments have begun investigating whether the disposal of produced water into underground injection wells has caused increased seismic activity in certain areas. For example, in December 2016, the EPA released its final report regarding the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances such as water withdrawals for fracturing in times or areas of low water availability, surface spills during the management of fracturing fluids, chemicals or produced water, injection of fracturing fluids into wells with inadequate mechanical integrity, injection of fracturing fluids directly into groundwater resources, discharge of inadequately treated fracturing wastewater to surface waters, and disposal or storage of fracturing wastewater in unlined pits. The results of these studies could lead federal and state governments and agencies to develop and implement additional regulations.

The proliferation of regulations may limit our ability to operate. 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. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the oil, natural gas and natural gas liquids we produce.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response, increasingly 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 pledged for the Paris Agreement to meet an economy-wide target in 2025 of reducing greenhouse gas emissions by 26-28% below the 2005 level. To help achieve these reductions, federal agencies have been addressing climate change through a variety of administrative actions. The EPA thus issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. 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, then President Obama released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and natural gas sector. Consistent with that strategy, the EPA issued final rules in 2016 for new and modified oil and natural gas production sources (including hydraulically fractured oil wells, natural gas well sites, natural gas processing plants, natural gas gathering and boosting stations and natural gas transmission sources) to reduce emissions of methane as well as volatile organic compound and toxic pollutants. However, in May 2017 the EPA temporarily stayed implementing portions of the new rule and in June 2017 proposed a two year stay of new requirements, and more recently the head of the EPA has announced the current administration's intent to roll back or repeal most, if not all, of the Obama administration's regulations restricting future greenhouse gas emissions. In June 2017, President Trump announced that the United States intends to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or a separate agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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.

The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions from the oil and natural gas industry. Even if federal efforts in this area slow, states may continue pursuing climate regulations. 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 oil and natural gas.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas and natural gas liquids, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to greater public scrutiny of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and natural gas exploration, development and production companies. Such legislative changes have included, but not limited to, (i) the repeal of the percentage depletion allowance for 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 domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. The Tax Cuts and Jobs Act of 2017 (the "TCJA") did not directly affect deductions currently available to the oil and natural gas industry but any future changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development, or increase costs, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The recently passed comprehensive tax reform bill could adversely affect our business and financial condition.

On December 22, 2017, President Trump signed into law the TCJA that significantly changes the federal income taxation of business entities. The TCJA, among other things, reduces the corporate income tax rate to 21%, partially limits the deductibility of business interest expense and net operating losses, imposes a one-time tax on unrepatriated earnings from certain foreign subsidiaries, taxes offshore earnings at reduced rates regardless of whether they are repatriated and allows the immediate deduction of certain capital expenditures instead of deductions for depreciation expense over time. We are still evaluating the overall impact of the TCJA to us. Notwithstanding the reduction in the corporate income tax rate, we cannot yet conclude that the overall impact of the TCJA to us is positive.

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.

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.

Red Mountain Capital Partners LLC and its affiliates ("Red Mountain") hold 22% of the voting power of our outstanding shares which gives Red Mountain a significant interest in the Company.

Red Mountain holds approximately 22% of our outstanding shares of common stock on an as-converted basis. Accordingly, Red Mountain has the ability to exert a significant degree of influence over our management and affairs and, as a practical matter, will significantly influence corporate actions requiring stockholder approval, irrespective of how our other stockholders may vote, including the election of directors, amendments to our certificate of incorporation and bylaws, and the approval of mergers and other significant corporate transactions, including a sale of substantially all of our assets, and Red Mountain may vote its shares in a manner that is adverse to the interests of our minority stockholders. For example, Red Mountain may be able to prevent a merger or similar transaction, including a transaction in which stockholders will receive a premium for their shares, even if our other stockholders are in favor of such transaction. Further, Red Mountain's position might adversely affect the market price of our common stock to the extent investors perceive disadvantages in owning shares of a company with a significant stockholder.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, as well as conduct reservoir modeling and reserve estimation for compliance reporting.

We are dependent on digital technologies including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees, business partners, and stockholders, analyze seismic and drilling information, estimate quantities of oil and natural gas reserves as well as other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production and financial institutions are also dependent on digital technology. The technologies needed to conduct oil and natural gas exploration, development and production activities make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for the purposes of misappropriating assets or sensitive information, corrupting data, causing operational disruption, or result in denial-of-service on websites.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period of time. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations.

We may not be able to keep pace with technological developments in the industry.

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

Terrorist attacks aimed at energy operations could adversely affect our business.

The continued threat of terrorism and the impact of military and other government action have led and may lead to further increased volatility in prices for oil and natural gas and could affect these commodity markets or the financial markets used by us. In addition, the U.S. government has issued warnings that energy assets may be a future target of terrorist organizations. These developments have subjected oil and natural gas operations to increased risks. Any future terrorist attack on our facilities, the infrastructure depended upon for transportation of products, and, in some cases, those of other energy companies, could have a material adverse effect on our business.

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, maintain and expand our company in 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, particularly unexpected losses, could have a material adverse effect on our business, operating results, financial condition and cash flows.

Risks Related to the Ownership of our Common Stock

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 oil and natural gas 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 American 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 was 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 American, 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 Amended and Restated Certificate of Incorporation authorizes 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 stockholders. 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.

Our failure to fulfill all of our registration requirements may cause us to suffer liquidated damages, which may be very costly.

Pursuant to the terms of the Registration Rights Agreement that we entered into with certain of our stockholders, we filed a registration statement with respect to securities issued and are required to maintain the effectiveness of such registration statement. There can be no assurance that we will be able to maintain the effectiveness of any registration statement, and therefore there can be no assurance that we will not incur damages with respect to such agreement.

Because we have no plans to pay dividends on our common stock, stockholders must look solely to a possible 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, stockholders must look solely to appreciation of our common stock to realize a gain on their investment, which may not occur.

Our Series D preferred stock has rights, preferences and privileges that are not held by, and are preferential to, the rights of our common stockholders. Such preferential rights could adversely affect our liquidity and financial condition and may result in the interests of the holders of the Series D preferred stock differing from those of our common stockholders.

In the event of any liquidation, dissolution or winding up of our company, whether voluntary or involuntary, or any other transaction deemed a liquidation event pursuant to the Certificate of Designation, including a sale of our company (a "Liquidation"), each holder of outstanding shares of our Series D preferred stock will be entitled to be paid out of our assets available for distribution to stockholders, before any payment may be made to the holders of our common stock, an amount per share equal to the original issue price, plus accrued and unpaid dividends thereon. If, upon such Liquidation, the amount that the holders of Series D preferred stock would have received if all outstanding shares of Series D preferred stock had been converted into shares of our common stock immediately prior to such Liquidation would exceed the amount they would receive pursuant to the preceding sentence, the holders of Series D preferred stock will receive such greater amount.

Dividends on the Series D preferred stock are cumulative and accrue quarterly, whether or not declared by our board of directors, at the rate of 7.0% per annum on the sum of the original issue price plus all unpaid accrued and unpaid dividends thereon, and payable in additional shares of Series D preferred stock. In addition to the dividends accruing on shares of Series D preferred stock described above, if we declare certain dividends on our common stock, we will be required to declare and pay a dividend on the outstanding shares of our Series D preferred stock on a pro rata basis with the common stock, determined on an as-converted basis. Our obligations to the holders of Series D preferred stock could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

There may be future dilution of our common stock.

We have a significant amount of derivative securities outstanding, which upon conversion, would result in substantial dilution. For example, the conversion of outstanding shares of Series D preferred stock in full could result in the issuance of approximately 3.2 million shares of common stock. To the extent outstanding stock appreciation rights under our long-term incentive plan are exercised or additional shares of restricted stock are issued to our employees, holders of our common stock will experience dilution. Furthermore, if we sell additional equity or convertible debt securities, such sales could result in further dilution to our existing stockholders and cause the price of our outstanding securities to decline.

If securities or industry analysts do not publish research or publish inaccurate or unfavorable research about our business, our stock price and trading volume could decline.

The trading market for our common stock will depend in part upon the research and reports that securities or industry analysts publish about us and our business. We do not currently have and may never obtain research coverage by securities and industry analysts. If no analysts commence coverage of our company, the trading price of our common stock might be negatively impacted. If we obtain securities or industry analyst coverage and if one or more of the analysts who covers us downgrades our stock or publishes inaccurate or unfavorable research about our business, our stock price would likely decline. If one or more of these analysts ceases coverage or fails to report about us on a regular basis, demand for our stock could decrease, which could cause our stock price and trading volume to decline.

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.

From time to time, we are party to various legal proceedings arising in the ordinary course of business. We expense or accrue legal costs as incurred. A summary of our legal proceedings is as follows:

Yuma Energy, Inc. v. Cardno PPI Technology Services, LLC Arbitration

On May 20, 2015, counsel for Cardno PPI Technology Services, LLC (“Cardno PPI”) sent a notice of the filing of liens totaling $304,209 on our Crosby 14 No. 1 Well and Crosby 14 SWD No. 1 Well in Vernon Parish, Louisiana. We disputed the validity of the liens and of the underlying invoices, and notified Cardno PPI that applicable credits had not been applied. We invoked mediation on August 11, 2015 on the issues of the validity of the liens, the amount due pursuant to terms of the parties’ Master Service Agreement (“MSA”), and PPI Cardno’s breaches of the MSA. Mediation was held on April 12, 2016; no settlement was reached.

On May 12, 2016, Cardno filed a lawsuit in Louisiana state court to enforce the liens; the Court entered an Order Staying Proceeding on June 13, 2016, ordering that the lawsuit “be stayed pending mediation/arbitration between the parties.” On June 17, 2016, we served a Notice of Arbitration on Cardno PPI, stating claims for breach of the MSA billing and warranty provisions. On July 15, 2016, Cardno PPI served a Counterclaim for $304,209 plus attorneys’ fees. The parties selected an arbitrator, and the initial arbitration hearing was held on March 29, 2018. The arbitration has been continued, with the next hearing to be held on April 12 and 13, 2018. Management intends to pursue our claims and to defend the counterclaim vigorously. 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 our consolidated financial statements.

The Parish of St. Bernard v. Atlantic Richfield Co., et al

On October 13, 2016, two of our subsidiaries, Yuma Exploration and Production Company (“Exploration”) and Yuma Petroleum Company (“YPC”), were named as defendants, among several other defendants, in an action by the Parish of St. Bernard in the Thirty-Fourth Judicial District of Louisiana. The petition alleges violations of the State and Local Coastal Resources Management Act of 1978, as amended, in the St. Bernard Parish. We have notified our insurance carrier of the lawsuit. Management intends to defend the plaintiffs’ claims vigorously. 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 our consolidated financial statements. The case has been removed to federal district court for the Eastern District of Louisiana. A motion to remand has been filed and the Court officially remanded the case on July 6, 2017. Exceptions for Exploration, YPC and the other defendants have been filed; however, the hearing for such exceptions was continued from the original date of October 6, 2017 to November 22, 2017. As a result of the November 22, 2017 hearing, the case will be de-cumulated into subcases, but the details of this are yet to be determined.

Cameron Parish vs. BEPCO LP, et al & Cameron Parish vs. Alpine Exploration Companies, Inc., et al.

The Parish of Cameron, Louisiana, filed a series of lawsuits against approximately 190 oil and gas companies alleging that the defendants, including Davis, have failed to clear, revegetate, detoxify, and restore the mineral and production sites and other areas affected by their operations and activities within certain coastal zone areas to their original condition as required by Louisiana law, and that such defendants are liable to Cameron Parish for damages under certain Louisiana coastal zone laws for such failures; however, the amount of such damages has not been specified. 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 our consolidated financial statements. Two of these lawsuits, originally filed February 4, 2016 in the 38th Judicial District Court for the Parish of Cameron, State of Louisiana, name Davis as defendant, along with more than 30 other oil and gas companies. Both cases have been removed to federal district court for the Western District of Louisiana. We deny these claims and intend to vigorously defend them. Davis has become a party to the Joint Defense and Cost Sharing Agreements for these cases. Motions to remand have been filed and the Magistrate Judge has recommended that the cases be remanded. We are still waiting for a new District Judge to be assigned to these cases and to rule on the remand recommendation.

Louisiana, et al. Escheat Tax Audits

The States of Louisiana, Texas, Minnesota, North Dakota and Wyoming have notified us that they will examine our 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. We have engaged Ryan, LLC to represent us in this matter. The exposure related to the audits is not currently determinable.

Louisiana Severance Tax Audit

The State of Louisiana, Department of Revenue, notified Exploration that it was auditing Exploration's calculation of its severance tax relating to Exploration's production from November 2012 through March 2016. The audit relates to the Department of Revenue's recent interpretation of long-standing oil purchase contracts to include a disallowable "transportation deduction," and thus to assert that the severance tax paid on crude oil sold during the contract term was not properly calculated. The Department of Revenue sent a proposed assessment in which they sought to impose $476,954 in additional state severance tax plus associated penalties and interest. Exploration engaged legal counsel to protest the proposed assessment and request a hearing. Exploration then entered a Joint Defense Group of operators challenging similar audit results. Since the Joint Defense Group is challenging the same legal theory, the Board of Tax Appeals proposed to hear a motion brought by one of the taxpayers that would address the rule for all through a test case. Exploration's case has been stayed pending adjudication of the test case. The hearing for the test case was held on November 7, 2017, and on December 6, 2017, the Board of Tax Appeals rendered judgment in favor of the taxpayer in the first of these cases. The Department of Revenue filed an appeal to this decision on January 5, 2018. 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 our consolidated financial statements.

Louisiana Department of Wildlife and Fisheries

We received notice from the Louisiana Department of Wildlife and Fisheries ("LDWF") in July 2017 stating that Exploration has open Coastal Use Permits ("CUPs") located within the Louisiana Public Oyster Seed Grounds dating back from as early as November 1993 and through a period ending in November 2012. The majority of the claims relate to permits that were filed from 2000 to 2005. Pursuant to the conditions of each CUP, LDWF is alleging that damages were caused to the oyster seed grounds and that compensation of an aggregate amount of approximately $500,000 is owed by the Company. We are currently evaluating the merits of the claim, are reviewing the LDWF analysis, and have now requested that the LDWF revise downward the amount of area their claims of damages pertain to. At this point in the regulatory process, no evaluation of the likelihood of an unfavorable outcome or associated economic loss can be made; therefore no liability has been recorded on our consolidated financial statements.

Miami Corporation – South Pecan Lake Field Area P&A

We, along with several other exploration and production companies in the chain of title, received letters from representatives of Miami Corporation demanding the performance of well plugging and abandonment, facility removal and restoration obligations for wells in the South Pecan Lake Field Area, Cameron Parish, Louisiana. Apache is one of the other companies in the chain of title, and after taking a field tour of the area, has sent to us, along with BP and other companies in the chain of title, a proposed work plan to comply with the Miami Corporation demand. We are currently evaluating the merits of the claim and the proposed work plan. At this point in the process, no evaluation of the likelihood of an unfavorable outcome or associated economic loss can be made; therefore no liability has been recorded on our consolidated financial statements.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Market Prices and Holders

Our common stock is listed for trading on the NYSE American under the symbol "YUMA." The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock on the NYSE American, adjusted to reflect the 1-for-20 reverse stock split that was completed on October 26, 2016 as part of the closing of the Davis Merger and our reincorporation from California to Delaware**.**

	Common Stock Price	
	High	Low
Quarter Ended		
2016		
March 31	$ 6.60	$ 3.00
June 30	$ 7.40	$ 3.80
September 30	$ 6.20	$ 3.98
December 31	$ 5.40	$ 1.94
2017		
March 31	$ 3.91	$ 2.06
June 30	$ 3.17	$ 0.81
September 30	$ 3.10	$ 0.77
December 31	$ 1.43	$ 0.85

As of April 2, 2018, there were approximately 116 stockholders 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 stockholders 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, our Credit Agreement does not permit us to pay dividends on our common stock.

Repurchases

The following table sets forth information regarding our acquisition of shares of common stock for the periods presented.

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 2017	910	$ 0.93	-	-
November 2017	-	-	-	-
December 2017	-	-	-	-

(1) All of the shares were surrendered by employees (via net settlement) in satisfaction of tax obligations upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of 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."

Recent developments

In 2017, we entered the Permian Basin through a joint venture with two privately held energy companies and established an Area of Mutual Interest ("AMI") covering approximately 33,280 acres in Yoakum County, Texas, located in the Northwest Shelf of the Permian Basin. The primary target within the AMI is the San Andres formation, which has been one of the largest producing formations in Texas to date. As of March 1, 2018, we held a 62.5% working interest in approximately 4,558 gross acres (2,849 net acres) within the AMI and intend to apply horizontal drilling technology to the San Andres formation. This activity is commonly referred to as the San Andres Horizontal Oil Play, and in certain areas, referred to as a Residual Oil Zone ("ROZ") Play due to the presence of residual oil zone fairways with substantial recoverable hydrocarbon resources in place. We are the operator of the joint venture and intend to acquire additional leases offsetting existing acreage. In December 2017, we sold a 12.5% working interest in ten sections of the project on a promoted basis and sold an additional 12.5% working interest in the same ten sections under the same terms in January 2018. On November 8, 2017, we spudded a salt water disposal well, the Jameson SWD #1, and completed that well on December 8, 2017. The rig was then moved to our State 320 #1H horizontal San Andres well, which we spudded on December 13, 2017. The State 320 #1H well reached total depth on January 2, 2018, and was subsequently completed and fraced, with the last stage being completed on February 15, 2018. After the frac was completed, we installed an ESP and placed the well on production on March 1, 2018. The well is currently in the early stages of recovering stimulation fluids and dewatering the near wellbore area.

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, 2017 and 2016, and the average sales price per unit sold.

	Years Ended December 31,	
	2017	2016
Production volumes:		
Crude oil and condensate (Bbls)	250,343	172,003
Natural gas (Mcf)	3,085,613	2,326,400
Natural gas liquids (Bbls)	131,155	104,689
Total (Boe) (1)	895,767	664,425
Average prices realized:		
Crude oil and condensate (per Bbl)	$ 50.32	$ 42.21
Natural gas (per Mcf)	$ 3.05	$ 2.45
Natural gas liquids (per Bbl)	$ 26.08	$ 17.33

(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, 2017 and 2016.

	Years Ended December 31,	
	2017	2016
Sales of natural gas and crude oil:		
Crude oil and condensate	$ 12,596,983	$ 7,260,169
Natural gas	9,425,676	5,697,879
Natural gas liquids	3,420,942	1,814,660
Total revenues	$ 25,443,601	$ 14,772,708

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 WTI and adjusted to LLS or HLS. 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 45.5%, or 78,340 Bbls, higher for the year ended December 31, 2017 compared to crude oil volumes sold during the year ended December 31, 2016. This increase was primarily due to the Davis Merger, as Yuma California's properties from the post-merger period in 2016 contributed 33,195 barrels compared to 172,713 barrels during 2017. Offsetting this increase were decreases in the El Halcón Field (32,605 barrels), which was divested during the second quarter of 2017, and declines in the Cameron Canal Field (13,207 barrels) and the Chalktown Field (12,457 barrels). Realized crude oil prices experienced a 19.2% increase from the year ended December 31, 2016 to the year ended December 31, 2017.

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, 2017 compared to the year ended December 31, 2016, we experienced a 32.6%, or 759,213 Mcf increase in natural gas volumes sold, primarily due to the Davis Merger, as Yuma California's properties from the post-merger period in 2016 contributed 212,089 Mcf compared to 1,327,969 Mcf in 2017. Offsetting this increase was a 269,936 Mcf decrease at the Cameron Canal Field and a 95,739 Mcf decrease at the Chalktown Field, offset by a 32,499 Mcf increase in volumes from the Lac Blanc Field. Realized natural gas prices experienced a 24.5% increase from the prior year ended December 31, 2016.

For the year ended December 31, 2017 compared to the year ended December 31, 2016, we experienced a 25.3%, or 26,466 Bbls increase in natural gas liquids volumes sold primarily due to the Davis Merger, as Yuma California's properties from the post-merger period in 2016 contributed 6,896 Bbls compared to 45,958 Bbls in 2017. Offsetting this increase was a 16,625 Bbl decrease at the Chalktown Field, offset by a 7,836 Bbl increase in volumes from the Lac Blanc Field. Realized natural gas liquids prices experienced a 50.5% increase from the prior year ended December 31, 2016.

Expenses

Lease Operating Expenses

Our lease operating expenses ("LOE") and LOE per Boe for the years ended December 31, 2017 and 2016, are set forth below:

	Years Ended December 31, 2017	Years Ended December 31, 2016
Lease operating expenses	$ 6,715,337	$ 3,303,789
Severance, ad valorem taxes and marketing	4,321,976	2,259,841
Total LOE	$ 11,037,313	$ 5,563,630
LOE per Boe	$ 12.32	$ 8.37
LOE per Boe without severance, ad valorem taxes and marketing	$ 7.50	$ 4.97

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 capital workovers.

The 98.4% increase in total LOE for the year ended December 31, 2017 compared to the year ended December 31, 2016 was primarily due to the Davis Merger, as Yuma California's properties from the post-merger period in 2016 contributed $1,401,451 compared to $6,682,086 during 2017. Also contributing to the increase were higher marketing and transportation costs, as well as production handling and salt water disposal fees, offset by lower contract labor, ad valorem tax, and chemical costs. LOE per Boe increased by 47.2% for the same period generally due to higher lease operating expenses when compared to the prior year.

General and Administrative Expenses

Our general and administrative ("G&A") expenses for the years ended December 31, 2017 and 2016, are summarized as follows:

	Years Ended December 31,	
	2017	2016
General and administrative:		
Stock-based compensation	$ 2,381,365	$ 3,449,667
Capitalized	-	(1,717,698)
Net stock-based compensation	2,381,365	1,731,969
Other	8,541,291	14,698,272
Capitalized	(1,606,910)	(1,970,944)
Net other	6,934,381	12,727,328
Net general and administrative expenses	$ 9,315,746	$ 14,459,297

G&A Other primarily consists 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, 2017, net G&A expenses were 35.6%, or $5,143,551, less than the amount for the prior year ended December 31, 2016. The decrease in G&A expenses was primarily attributed to a $3,003,042 reduction in direct costs related to the Davis Merger, as well as reductions of $2,651,170 and $753,873 for salaries and third party tax, audit and accounting fees, respectively, both also related to the Davis Merger. These reductions were offset by a $649,396 increase in net stock-based compensation, a $508,681 increase in fees for consultants and contract labor, a $202,583 increase in board fees, and a $279,832 increase related to legal expenses.

Depreciation, Depletion and Amortization

Our depreciation, depletion and amortization ("DD&A") for oil and natural gas properties (excluding DD&A related to other property, plant and equipment) for the years ended December 31, 2017 and 2016, is summarized as follows:

	Years Ended December 31,	
	2017	2016
DD&A	$ 10,724,967	$ 7,756,107
DD&A per Boe	$ 11.97	$ 11.67

DD&A expense increased $2,968,860, or 38.3%, for the year ended December 31, 2017 compared to the year ended December 31, 2016. The increase resulted primarily from increased production in 2017 as a result of the Davis Merger.

Impairment of Oil and Natural Gas Properties

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling," based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. We recorded a full cost ceiling test impairment of $-0- and $20.7 million for the years ended December 31, 2017 and 2016, respectively. The impact of low commodity prices that adversely affected estimated proved reserve volumes and future estimated revenues was the primary contributor to the ceiling impairment in 2016. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Interest Expense

Our interest expense for the years ended December 31, 2017 and 2016, is summarized as follows:

	Years Ended December 31,	
	2017	2016
Interest expense	$ 2,052,498	$ 685,693
Interest capitalized	(317,691)	(26,121)
Net	$ 1,734,807	$ 659,572
Bank debt	$ 27,700,000	$ 39,500,000

Interest expense (net of amounts capitalized) increased $1,075,235 for the year ended December 31, 2017 over the same period in 2016 as a result of higher borrowings following the Davis Merger on October 26, 2016.

For a more complete narrative of interest expense, refer to Note 15 – 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, 2017 and 2016:

	Years Ended December 31,	
	2017	2016
Consolidated net income (loss) before income taxes	$ (5,392,768)	$ (40,173,369)
Income tax expense (benefit)	$ -	$ 1,425,964
Effective tax rate	(0.00%)	(3.55%)

Differences between the U.S. federal statutory rate of 35% and our effective tax rates are due to the tax effects of valuation allowances recorded against our deferred tax assets, stock compensation shortfalls, and non-deductible expenses. Refer to Note 17 – Income Taxes in the Notes to Consolidated Financial Statements included in this report.

Liquidity and Capital Resources

We are an exploration and production company with interests in conventional and non-conventional oil and gas properties that require significant investments of capital and time to develop and commence production activities. As of January 1, 2018, our 2018 business plan included the capital to drill four gross (2.5 net) wells (including the State 320 #1H) with an aggregate net capital budget of approximately $7.5 million, excluding capitalized G&A and interest. Other net capital investments of approximately $2.5 million are also planned for land costs, workovers and plugging and abandonment costs. 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. As of December 31, 2017, we had outstanding borrowings of $27.7 million under our credit facility, and our total borrowing base was $40.5 million, leaving $12.8 million of undrawn borrowing base. Our cash flows from operations are a key component of our ability to invest in and maintain our properties and service our long term obligations. A portion of our cash flows from operating activities are subject to volatility due to changes in commodity prices, as well as variations in our production, which can be attributed to natural declines and/or unforeseen events.

Our plans to mitigate our limited liquidity and the effects of commodity prices on our operations include: closely monitoring capital expenditures planned for 2018 to conserve capital; entering into commodity derivatives for a significant portion of our anticipated production for 2018 (excluding NGL volumes); potentially raising proceeds from capital markets transactions, including the sale of debt or equity securities; and possibly selling certain non-core assets.

As a result of the steps we have taken to enhance our liquidity, we anticipate 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 will be sufficient to meet our investing, financing, and working capital requirements; however, we are subject to a number of factors that are beyond our control, including commodity prices, our bank's determination of our borrowing base, normal and unusual production declines, and other factors that could adversely affect our financial positions, results of operations and liquidity.

Cash Flows

Our net increase (decrease) in cash for the years ended December, 31, 2017 and 2016, is summarized as follows:

	Years Ended December 31,	
	2017	**2016**
Cash flows provided by (used in) operating activities	$ 3,246,058	$ (4,299,238)
Cash flows used in investing activities	(3,419,840)	(5,419,250)
Cash flows provided by (used in) financing activities	(3,314,541)	9,280,080
Net increase (decrease) in cash	$ (3,488,323)	$ (438,408)

Cash Flows From Operating Activities

Net cash provided by operating activities was $3,246,058 for the year ended December 31, 2017 compared to $4,299,238 in cash used during the same period in 2016. This increase was primarily caused by increased revenue as a result of higher sales volumes due to the Davis Merger and higher realized commodity prices, offset by increases in LOE. In addition, G&A expenses decreased because of merger-related payments, including severance, in 2016. Funds were also used for a $2,462,040 reduction in liabilities and $1,045,257 in the settlement of asset retirement obligations.

One of the primary sources of variability in our cash flows from operating activities is fluctuations in commodity prices, the impact of which we partially mitigate by entering into commodity derivatives. Sales volume changes also impact cash flow. Our cash flows from operating activities are also dependent on the costs related to continued operations.

Cash Flows From Investing Activities

Net cash used in investing activities was $3,419,840 for the year ended December 31, 2017 compared to $5,419,250 in cash used during the same period in 2016. During the year ended December 31, 2017, we had a total of $10,704,535 in oil and natural gas investing activities. Of that, $1,894,685 related to the drilling of the Weyerhaeuser 14 #1, $1,723,565 related to the recompletion of the State Lease 14564 #4 well, $1,016,002 related to the SL 18090 #2 well to establish production from the SIPH-D1 zone, $2,165,139 was for the drilling of the Jameson #1 SWD and $2,321,794 was spent on lease acquisition costs related to our Permian Basin project. These amounts were offset by $5,400,563 related to proceeds from the sale of oil and natural gas properties, and $1,238,341 related to settlements of commodity derivatives. In addition, $1,606,910 was capitalized G&A related to land, geological and geophysical costs.

In 2016, we had a total of $10,066,999 in oil and natural gas investing activities. Of that, $6,274,650 was related to the drilling and completion of the EE Broussard #1, and $2,624,349 was spent on lease acquisition costs, which included $1,970,944 in capitalized G&A related to land, geological and geophysical costs. Recompletions and workovers totaled $935,330, with notable projects including the Oustalet Farms, LLC #1 recompletion for $573,720 and the SL 15164 #1 workover for $153,097.

Cash Flows From Financing Activities

During the year ended December 31, 2017, we had net cash used in financing activities of $3,314,541. Of that amount, $11,800,000 was used for repayments net of borrowing on our credit facility and $711,461 was used for payments on our insurance financing. New insurance financing was $763,244. In addition, we paid debt issuance costs of $353,593. This was primarily offset by net cash received from our equity offering during 2017 of $8.8 million.

At December 31, 2017, we had a $40,500,000 borrowing base under our credit facility with $27,700,000 advanced, leaving a borrowing capacity of $12,800,000.

We had a cash balance of $137,363 at December 31, 2017.

Underwritten Public Offering

In September and October 2017, we completed a public offering of 10,100,000 shares of common stock (including 500,000 shares purchased pursuant to the underwriter's overallotment option), at a public offering price of $1.00 per share. We received net proceeds from this offering of approximately $8.7 million, after deducting underwriters' fees and offering expenses of $1.4 million.

Credit Facility

We have a credit facility with a syndicate of banks that, as of December 31, 2017, had a borrowing base of $40.5 million which was reaffirmed as of September 8, 2017. The Credit Agreement governing our credit facility provides for interest-only payments until October 26, 2019, 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 covering at least 95% of the PV10 value of the proved oil and gas properties included in the determination of the borrowing base.

The amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus 3.00% to 4.00% or (b) the prime lending rate of SocGen plus 2.00% to 3.00%, depending on the amount borrowed under the credit facility and whether the loan is drawn in U.S. dollars or Euro dollars. The interest rate for the credit facility at December 31, 2017 was 5.07% for LIBOR-based debt and 7.00% for prime-based debt. Principal amounts outstanding under the credit facility are due and payable in full at maturity on October 26, 2019. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of our assets. Additional payments due under the Credit Agreement include paying a commitment fee to the Lender in respect of the unutilized commitments thereunder. The commitment rate is 0.50% per year of the unutilized portion of the borrowing base in effect from time to time. We are also required to pay customary letter of credit fees.

In addition, the Credit Agreement requires us to maintain the following financial covenants: a current ratio of not less than 1.0 to 1.0 on the last day of each quarter, a ratio of total debt to earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses ("EBITDAX") ratio of not greater than 3.5 to 1.0 for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding such date of determination, and a ratio of EBITDAX to interest expense of not less than 2.75 to 1.0 for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding such date of determination, and cash and cash equivalent investments together with borrowing availability under the Credit Agreement of at least $4.0 million. The Credit Agreement contains customary affirmative covenants and defines events of default for credit facilities of this type, including failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default, and a change of control. Upon the occurrence and continuance of an event of default, the Lender has the right to accelerate repayment of the loans and exercise its remedies with respect to the collateral. As of December 31, 2017, we were in compliance with the covenants under the Credit Agreement.

Our credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to stockholders, repurchases or redemptions of our common stock, payment of cash dividends on our preferred stock, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, commodity derivative transactions and other matters. See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 15 – Debt and Interest Expense.

Commodity Derivative 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 commodity derivative 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, 2017		December 31, 2016	
	Oil	Natural Gas	Oil	Natural Gas
Assets				
Current	$ -	$ -	$ -	$ -
Noncurrent	$ -	$ -	$ -	$ -
Liabilities				
Current	$ (1,198,307)	$ 295,304	$ (24,140)	$ (1,316,311)
Noncurrent	$ (319,104)	$ (17,302)	$ (932,857)	$ (282,694)

Assets and liabilities are netted within each commodity on the Consolidated Balance Sheets 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 11 – Commodity Derivative Instruments.

The fair market value of our commodity derivative contracts in place at December 31, 2017 and December 31, 2016 were net liabilities of $1,239,409 and $2,556,002, respectively.

See Part II, Item 8. Notes to the Consolidated Financial Statements, Note 11 – Commodity Derivative Instruments, for additional information on our commodity derivatives.

Commodity derivative prices for a portion of our production is a fundamental part of our corporate financial management. In implementing our commodity derivative 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, 2017:

	Debt (1)	Liability for Commodity Derivatives (2)	Throughput Commitment (3)	Operating Leases	Asset Retirement Obligations	Total
2018	$ -	$ 903,003	$ 342,618	$ 486,805	$ 277,355	$ 2,009,781
2019	27,700,000	336,406	344,503	534,294	511,145	29,426,348
2020	-	-	86,126	522,850	354,025	963,001
2021	-	-	-	529,574	646,108	1,175,682
2022	-	-	-	536,790	407,073	943,863
Thereafter	-	-	-	358,282	8,270,707	8,628,989
Totals	$ 27,700,000	$ 1,239,409	$ 773,247	$ 2,968,595	$ 10,466,413	$ 43,147,664

(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, 2017. These amounts will change as oil and natural gas commodity prices change.

(3) Our Chalktown properties are subject to a throughout commitment agreement through March 2020. Since we have failed to reach volume commitments and anticipate that we will fail to reach such commitments for the remainder of the agreement, we are accruing approximately $30,000 per month which is the maximum amount we may owe based upon the agreement. See Note 18 – Commitments and Contingencies in the Notes to Consolidated Financial Statements in Part II, Item 8 in this report.

Additionally, in connection with our joint venture in the Permian Basin of Yoakum County, Texas, we are committed as of December 31, 2017 to spend an additional $984,068 by March 2020.

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 2 – 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 price 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 subject to amortization, net of accumulated 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 unproved properties not subject to amortization, 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 the income statement and a write-down of oil and natural gas properties subject to amortization in the quarter in which the excess occurs.

Given the volatility of oil and natural gas prices, our estimate of discounted future net cash flows from estimated proved oil and natural gas reserves may change significantly in the future.

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.

Commodity Derivative 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 Sheets. The changes in the fair value of the derivative instruments are recorded in the Consolidated Statements of Operations.

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

Share-based Compensation

We have four types of long-term incentive awards – restricted stock awards (“RSAs”), stock options (“SOs”), 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, SOs and some of our SARs are treated as equity since our intention is to settle them in stock. Our cash settled SARs are treated as a liability since our intention is to settle them in cash. The costs associated with RSAs, SOs and equity-based SARs are valued at the time of issuance and amortized over the vesting period of the awards.

Purchase Price Allocations

We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations, such as the Davis Merger in 2016. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. In most cases, sufficient market data is not available regarding the fair values of proved and unproved properties and we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of crude oil, natural gas and NGL reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risk factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known or as tax laws and regulations change. See Part II, Item 8. Note 17 – Income Taxes in the Notes to the Consolidated Financial Statements.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows, but would result in a decrease in net income for the period in which the impairment is recorded. See Item 8, Notes to the Consolidated Financial Statements, Note 4 – Acquisitions and Divestments.

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 Reports of the Independent Registered Public Accounting Firms 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.

As previously disclosed in the Company’s Current Report on Form 8-K, filed with the SEC on July 11, 2017, effective July 10, the Company dismissed Grant Thornton LLP (“Grant Thornton”) as the Company’s independent registered public accounting firm and appointed Hein & Associates LLP (“Hein”) to serve as the Company’s new independent registered public accounting firm to audit the Company’s financial statements as of and for the fiscal year ended December 31, 2017. In connection with this change in the Company’s independent registered public accounting firm, there was no disagreement, as defined in Item 304(a)(1)(iv) of Regulation S-K, or a reportable event, as defined in Item 304(a)(1)(v) of Regulation S-K.

As previously disclosed in the Company's Current Report on Form 8-K, filed with the SEC on November 16, 2017, effective November 16, 2017, Hein, the previous independent registered public accounting firm for the Company, combined with Moss Adams LLP ("Moss Adams"). As a result of this transaction, on November 16, 2017, Hein resigned as the independent registered public accounting firm for the Company. Concurrent with such resignation, the Company's audit committee approved the engagement of Moss Adams as the new independent registered public accounting firm for the Company. In connection with this change in the Company's independent registered public accounting firm, there was no disagreement, as defined in Item 304(a)(1)(iv) of Regulation S-K, or a reportable event, as defined in Item 304(a)(1)(v) of Regulation S-K.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(e) and 15d-15(e), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2017.

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, our management concluded that, as of December 31, 2017, our internal control over financial reporting was effective.

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 were no significant changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of the fiscal year ended December 31, 2017 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.

Other information required by this item 10 of this report will be set forth in our 2018 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

Item 11. Executive Compensation.

Information called for by Item 11 of this report will be set forth in our 2018 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

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

Information called for by Item 12 of this report will be set forth in our 2018 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

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

Information called for by Item 13 of this report will be set forth in our 2018 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

Information called for by Item 14 of this report will be set forth in our 2018 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

Form 10-K for the fiscal year ended December 31, 2017.

		Incorporated by Reference					
Exhibit No.	Description	Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
2.1	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		
2.1(a)	First Amendment to the Agreement and Plan of Merger and Reorganization dated as of September 2, 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	September 6, 2016		
3.1	Certificate of Incorporation dated February 10, 2016.	S-4	333-212103	3.4	August 4, 2016		
3.1(a)	Certificate of Amendment of Certificate of Incorporation dated October 26, 2016.	8-K	001-37932	3.1	November 1, 2016		
3.2	Amended and Restated Certificate of Incorporation dated October 26, 2016.	8-K	001-37932	3.2	November 1, 2016		
3.3	Certificate of Designation of the Series D Convertible Preferred Stock of Yuma Energy, Inc. dated October 26, 2016.	8-K	001-37932	3.3	November 1, 2016		
3.4	Bylaws dated February 10, 2016.	S-4	333-212103	3.5	August 4, 2016		
3.5	Amended and Restated Bylaws dated October 26, 2016.	8-K	001-37932	3.4	November 1, 2016		
10.1	Credit Agreement dated as of October 26, 2016, among Yuma Energy, Inc., Yuma Exploration and Production Company, Inc., Pyramid Oil LLC, Davis Petroleum Corp., Société Générale, SG Americas Securities, LLC and the lenders party thereto.	8-K	001-37932	10.1	November 1, 2016		
10.1(a)	First Amendment to Credit Agreement and Borrowing Base Redetermination dated May 19, 2017 among Yuma Energy, Inc., Yuma Exploration and Production Company, Inc., Pyramid Oil LLC, Davis Petroleum Corp., Société Générale, as Administrative Agent, and each of the lenders and guarantors party thereto.	8-K	001-37932	10.1	May 23, 2017		
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		
10.2(a)†	First Amendment to the Employment Agreement dated October 26, 2016, between Yuma Energy, Inc. and Sam L. Banks.	8-K	001-37932	10.5(a)	November 1, 2016		

10.2(b)†	Amended and Restated Employment Agreement dated April 20, 2017 between Yuma Energy, Inc. and Sam L. Banks.	8-K	001-37932	10.1	April 26, 2017	
10.3†	Employment Agreement dated July 15, 2013, between Yuma Energy, Inc. and James J. Jacobs.	S-4	333-212103	10.7	June 17, 2016	
10.3(a)†	Amended and Restated Employment Agreement dated April 20, 2017 between Yuma Energy, Inc. and James J. Jacobs.	8-K	001-37932	10.3	April 26, 2017	
10.4†	Employment Agreement dated October 14, 2014, between Yuma Energy, Inc. and Paul D. McKinney.	10-Q	001-32989	10.1	November 14, 2014	
10.4(a)†	Amendment to the Employment Agreement dated March 12, 2015, between Yuma Energy, Inc. and Paul D. McKinney.	8-K	001-32989	10.1	March 17, 2015	
10.4(b)†	Amended and Restated Employment Agreement dated April 20, 2017 between Yuma Energy, Inc. and Paul D. McKinney.	8-K	001-37932	10.2	April 26, 2017	
10.5	Form of Indemnification Agreement.	8-K	001-37932	10.2	November 1, 2016	
10.6	Registration Rights Agreement dated October 26, 2016.	8-K	001-37932	10.3	November 1, 2016	
10.7	Form of Lock-up Agreement.	8-K	001-37932	10.4	November 1, 2016	
10.8†	2006 Equity Incentive Plan of the Registrant.	S-8	333-175706	4.3	July 21, 2011	
10.9†	Yuma Energy, Inc. 2011 Stock Option Plan.	8-K	001-32989	10.5	September 16, 2014	
10.10†	Yuma Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-32989	10.6	September 16, 2014	
10.10(a)†	Amendment to the Yuma Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-37932	10.7(a)	November 1, 2016	
10.25†	Form of Restricted Stock Award Agreement (Employees).	8-K	001-37932	10.1	March 27, 2017	
10.26†	Form of Restricted Stock Award Agreement (Directors).	8-K	001-37932	10.2	March 27, 2017	
10.27†	Form of Stock Appreciation Right Agreement.	8-K	001-37932	10.4	April 26, 2017	
10.28†	Form of Stock Option Agreement.	8-K	001-37932	10.5	April 26, 2017	
14	Code of Ethics.	8-K	001-37932	14	November 1, 2016	
21.1	List of Subsidiaries.					X
23.1	Consent of Moss Adams LLP.					X
23.2	Consent of Grant Thornton LLP.					X
23.3	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.

Item 16. Form 10-K Summary.

The Company has opted not to include a summary of information required by this Form 10-K as permitted by this Item.

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: April 2, 2018	Title:	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	Director and Chief Executive Officer (Principal Executive Officer)	April 2, 2018
/s/ James J. Jacobs James J. Jacobs	Chief Financial Officer, Treasurer and Corporate Secretary (Principal Financial Officer and Principal Accounting Officer)	April 2, 2018
/s/ James W. Christmas James W. Christmas	Director	April 2, 2018
/s/ Frank A. Lodzinski Frank A. Lodzinski	Director	April 2, 2018
/s/ Neeraj Mital Neeraj Mital	Director	April 2, 2018
/s/ Richard K. Stoneburner Richard K. Stoneburner	Director	April 2, 2018
/s/ J. Christopher Teets J. Christopher Teets	Director	April 2, 2018

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of
Yuma Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Yuma Energy, Inc. and subsidiaries (the "Company") as of December 31, 2017, the related consolidated statements of operations, changes in equity and cash flows for the year then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting 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.

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

/s/ Moss Adams LLP

Houston, Texas
April 2, 2018

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Yuma Energy, Inc.

We have audited the accompanying consolidated balance sheet of Yuma Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2016, and the related consolidated statements of operations, changes in equity, and cash flows for the year then ended. 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 audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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 audit 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 audit provides 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, 2016, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas

April 12, 2017

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 137,363	$ 3,625,686
Accounts receivable, net of allowance for doubtful accounts:		
Trade	4,496,316	4,827,798
Officer and employees	53,979	68,014
Other	1,004,479	1,757,337
Prepayments	976,462	1,063,418
Other deferred charges	347,490	284,305
Total current assets	7,016,089	11,626,558
OIL AND GAS PROPERTIES (full cost method):		
Proved properties	494,216,531	488,723,905
Unproved properties - not subject to amortization	6,794,372	3,656,989
	501,010,903	492,380,894
Less: accumulated depreciation, depletion and amortization	(421,165,400)	(410,440,433)
Net oil and gas properties	79,845,503	81,940,461
OTHER PROPERTY AND EQUIPMENT:		
Land, buildings and improvements	1,600,000	1,600,000
Other property and equipment	2,845,459	7,136,530
	4,445,459	8,736,530
Less: accumulated depreciation and amortization	(1,409,535)	(5,349,145)
Net other property and equipment	3,035,924	3,387,385
OTHER ASSETS AND DEFERRED CHARGES:		
Deposits	467,592	467,306
Other noncurrent assets	270,842	517,201
Total other assets and deferred charges	738,434	984,507
TOTAL ASSETS	$ 90,635,950	$ 97,938,911

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

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS - CONTINUED

	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of debt	$ 651,124	$ 599,341
Accounts payable, principally trade	11,931,218	11,009,631
Commodity derivative instruments	903,003	1,340,451
Asset retirement obligations	277,355	376,735
Other accrued liabilities	2,295,438	2,572,680
Total current liabilities	16,058,138	15,898,838
LONG-TERM DEBT	27,700,000	39,500,000
OTHER NONCURRENT LIABILITIES:		
Asset retirement obligations	10,189,058	9,819,648
Commodity derivative instruments	336,406	1,215,551
Deferred rent	290,566	-
Employee stock awards	191,110	-
Total other noncurrent liabilities	11,007,140	11,035,199
COMMITMENTS AND CONTINGENCIES (Note 18)		
EQUITY		
Series D convertible preferred stock ($0.001 par value, 7,000,000 authorized, 1,904,391 issued and outstanding as of December 31, 2017, and 1,776,718 issued and outstanding as of December 31, 2016)	1,904	1,777
Common stock ($0.001 par value, 100 million shares authorized, 22,661,758 outstanding as of December 31, 2017 and 12,201,884 outstanding as of December 31, 2016)	22,662	12,202
Additional paid-in capital	55,064,685	43,877,563
Treasury stock at cost (13,343 shares as of December 31, 2017 and -0- shares as of December 31, 2016)	(25,278)	-
Accumulated earnings (deficit)	(19,193,301)	(12,386,668)
Total equity	35,870,672	31,504,874
TOTAL LIABILITIES AND EQUITY	$ 90,635,950	$ 97,938,911

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2017	2016
REVENUES:		
Sales of natural gas and crude oil	$ 25,443,601	$ 14,772,708
EXPENSES:		
Lease operating and production costs	11,037,313	5,563,630
General and administrative – stock-based compensation	2,381,365	1,731,969
General and administrative – other	6,934,381	12,727,328
Depreciation, depletion and amortization	10,955,203	8,239,802
Asset retirement obligation accretion expense	557,683	254,573
Impairment of oil and gas properties	-	20,654,848
Bad debt expense	335,567	556,407
Total expenses	32,201,512	49,728,557
LOSS FROM OPERATIONS	(6,757,911)	(34,955,849)
OTHER INCOME (EXPENSE):		
Net gains (losses) from commodity derivatives	2,554,934	(3,775,254)
Interest expense	(1,734,807)	(659,572)
Gain (loss) on other property and equipment	484,768	(838,473)
Other, net	60,248	55,779
Total other income (expense)	1,365,143	(5,217,520)
LOSS BEFORE INCOME TAXES	(5,392,768)	(40,173,369)
Income tax expense - deferred	-	1,425,964
NET LOSS	(5,392,768)	(41,599,333)
PREFERRED STOCK:		
Dividends paid in kind	1,413,865	1,323,641
Loss on retirement of DPAC Series "A" Preferred Stock	-	(271,914)
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ (6,806,633)	$ (42,651,060)
LOSS PER COMMON SHARE:		
Basic	$ (0.46)	$ (5.13)
Diluted	$ (0.46)	$ (5.13)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:		
Basic	14,815,991	8,317,777
Diluted	14,815,991	8,317,777

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Preferred Stock		Common Stock		Additional Paid-in Capital	Treasury Stock	Accumulated Deficit	Stockholders' Equity
	Shares	Value	Shares	Value				
December 31, 2015	33,367,187	$ 333,672	7,440,152	$ 7,440	$ 209,512,985	$ (41,350,488)	$ (119,376,290)	$ 49,127,319
Net loss	-	-	-	-	-	-	(41,599,333)	(41,599,333)
Payment of DPAC Series "A" dividends in kind	1,952,801	19,528	-	-	1,054,513	-	(1,074,041)	-
Retirement of DPAC Series "A" preferred stock	(35,319,988)	(353,200)	-	-	(18,800,880)	-	(271,914)	(19,425,994)
Issuance of Series "D" preferred stock	1,754,179	1,754	-	-	19,424,240	-	-	19,425,994
Payment of Series "D" dividends in kind	22,539	23	-	-	249,577	-	(249,600)	-
DPAC stock awards vested	-	-	14,651	15	98,335	-	-	98,350
Reclass DPAC equity at merger to paid-in capital	-	-	-	-	(150,184,510)	-	150,184,510	-
Common stock at merger	-	-	4,746,180	4,746	20,930,798	-	-	20,935,544
Stock awards vested	-	-	901	1	(1)	-	-	-
Amortization of stock-based compensation	-	-	-	-	3,351,317	-	-	3,351,317
Treasury stock - employee tax payment	-	-	-	-	-	(408,323)	-	(408,323)
Retire DPAC treasury stock	-	-	-	-	(41,758,811)	41,758,811	-	-
December 31, 2016	1,776,718	$ 1,777	12,201,884	$ 12,202	$ 43,877,563	$ -	$ (12,386,668)	$ 31,504,874
Net loss	-	-	-	-	-	-	(5,392,768)	(5,392,768)
Payment of Series "D" dividends in kind	127,673	127	-	-	1,413,738	-	(1,413,865)	-
Public offering proceeds net of $1.4 million costs	-	-	10,100,000	10,100	8,737,447	-	-	8,747,547
Stock awards vested	-	-	32,596	33	(33)	-	-	-
Restricted stock awards issued	-	-	329,491	329	(329)	-	-	-
Restricted stock awards forfeited	-	-	(2,213)	(2)	2	-	-	-
Amortization of stock-based compensation	-	-	-	-	1,036,297	-	-	1,036,297
Treasury stock (surrendered to settle employee tax liabilities)	-	-	-	-	-	(25,278)	-	(25,278)
December 31, 2017	1,904,391	$ 1,904	22,661,758	$ 22,662	$ 55,064,685	$ (25,278)	$ (19,193,301)	$ 35,870,672

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Reconciliation of net income (loss) to net cash provided by (used in) operating activities:		
Net income (loss)	$ (5,392,768)	$ (41,599,333)
Depreciation, depletion and amortization of property and equipment	10,955,203	8,239,802
Impairment of oil and gas properties	-	20,654,848
Amortization of debt issuance costs	363,485	148,970
Net deferred income tax expense	-	1,425,964
Deferred rent liability, net	279,795	-
Stock-based compensation expense	2,381,365	1,731,969
Settlement of asset retirement obligations	(1,045,257)	(287,902)
Asset retirement obligation accretion expense	557,683	254,573
Bad debt expense	335,567	556,406
Net (gains) losses from commodity derivatives	(2,554,934)	3,775,254
(Gain) loss on sales of fixed assets	(556,141)	5,316
Loss on write-off of abandoned facilities	71,373	829,039
(Gain) loss on write-off of liabilities net of assets	(58,994)	4,118
Changes in assets and liabilities:		
Decrease in accounts receivable	285,051	3,698,004
Decrease in prepaids, deposits and other assets	86,670	353,889
Decrease in accounts payable and other current and non-current liabilities	(2,462,040)	(4,090,155)
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	3,246,058	(4,299,238)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures for oil and gas properties	(10,704,535)	(10,066,999)
Proceeds from sale of oil and gas properties	5,400,563	1,152,958
Merger with Yuma California	-	1,887,426
Proceeds from sale of other fixed assets	645,791	-
Derivative settlements	1,238,341	1,607,365
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(3,419,840)	(5,419,250)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings on senior credit facility	13,275,000	18,700,000
Repayment of borrowings on senior credit facility	(25,075,000)	(9,000,000)
Proceeds from borrowings - insurance financing	763,244	247,013
Repayments of borrowings - insurance financing	(711,461)	(49,625)
Debt issuance costs	(353,593)	(208,985)
Proceeds net of costs from common stock offering	8,812,547	-
Treasury stock repurchases	(25,278)	(408,323)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(3,314,541)	9,280,080
NET DECREASE IN CASH AND CASH EQUIVALENTS	(3,488,323)	(438,408)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	3,625,686	4,064,094
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 137,363	$ 3,625,686
Supplemental disclosure of cash flow information:		
Interest payments (net of interest capitalized)	$ 1,369,353	$ 590,160
Interest capitalized	$ 317,691	$ 26,121
Income tax refund	$ 20,699	$ -
Supplemental disclosure of significant non-cash activity:		
(Increase) decrease in capital expenditures financed by accounts payable	$ (2,608,232)	$ 323,910

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

NOTE 1 – ORGANIZATION AND BASIS OF PRESENTATION

Yuma Energy, Inc., a Delaware corporation ("YEI" and collectively with its subsidiaries, the "Company"), is an independent Houston-based exploration and production company focused on acquiring, developing and exploring for conventional and unconventional oil and natural gas resources. Historically, the Company's operations have focused on onshore properties located in central and southern Louisiana and southeastern Texas where it has a long history of drilling, developing and producing both oil and natural gas assets. More recently, it has begun acquiring acreage in Yoakum County, Texas, with plans to explore and develop additional oil and natural gas assets in the Permian Basin of West Texas. Finally, the Company has operated positions in Kern County, California, and non-operated positions in the East Texas Woodbine and the Bakken Shale in North Dakota.

On October 26, 2016, Yuma Energy, Inc., a California corporation ("Yuma California"), merged (the "Reincorporation Merger") with and into YEI. Pursuant to the Reincorporation Merger, Yuma California was reincorporated in Delaware as YEI. Immediately thereafter, a wholly owned subsidiary of YEI merged (the "Davis Merger") with and into privately-held Davis Petroleum Acquisition Corp., a Delaware corporation ("Davis"). As a result of the Davis Merger, Davis became a wholly owned subsidiary of YEI.

Prior to the Reincorporation Merger, each share of Yuma California's existing 9.25% Series A Cumulative Redeemable Preferred Stock, no par value per share (the "Yuma California Series A Preferred Stock"), was converted into 35 shares of common stock, no par value per share, of Yuma California ("Yuma California Common Stock"). As a result of the closing of the Reincorporation Merger, each share of Yuma California Common Stock was converted into one-twentieth of one (1) share (the "Reverse Stock Split") of common stock, $0.001 par value per share of YEI (the "common stock"). As a result of the Reverse Stock Split, YEI issued an aggregate of approximately 4.75 million shares of its common stock.

As a result of the Davis Merger, YEI issued approximately 7.45 million shares of its common stock to the former stockholders of Davis common stock. YEI also issued approximately 1.75 million shares of Series D Convertible Preferred Stock, $0.001 par value per share, of YEI (the "Series D Preferred Stock"), to existing Davis preferred stockholders. Upon completion of the Reincorporation Merger and the Davis Merger, there was an aggregate of approximately 12.2 million shares of common stock outstanding and 1.75 million shares of Series D Preferred Stock outstanding.

The Davis Merger was accounted for as a "reverse acquisition" and a recapitalization since the former common stockholders of Davis had control over the combined company through their post-merger 61.1% ownership of the common stock and majority representation on YEI's board of directors as of the closing of the Davis Merger. The transaction qualified as a tax-deferred reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended (the "Code").

The Davis 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 value. Although YEI was the legal acquirer, Davis was the accounting acquirer. The historical financial statements are those of Davis. Hence, the financial statements included herein reflect (i) the historical results of Davis prior to the Davis Merger; (ii) the combined results of the Company following the Davis Merger; (iii) the acquired assets and liabilities of Davis at the their historical cost; and (iv) the fair value of Yuma California's assets and liabilities at the close of the Davis Merger (see Note 4 – Acquisitions and Divestments, for further information).

Basis of Presentation

The accompanying financial statements include the accounts of YEI on a consolidated basis. All significant intercompany accounts and transactions between YEI and its wholly owned subsidiaries have been eliminated in the consolidation.

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 Consolidation

YEI has 10 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	10/30/1996
Yuma Exploration and Production Company, Inc.	"Exploration"	Delaware	01/16/1992
Davis Petroleum Acquisition Corp.	"DPAC"	Delaware	01/18/2006
Davis Petroleum Pipeline LLC	"DPP"	Delaware	11/15/1999
Davis GOM Holdings, LLC	"Davis GOM"	Delaware	07/25/2014
Davis Petroleum Corp.	"DPC"	Delaware	07/08/1986
Yuma Petroleum Company	"Petroleum"	Delaware	12/19/1991
Texas Southeastern Gas Marketing Company	"TSM"	Texas	09/12/1996
Pyramid Oil LLC	"POL"	California	08/08/2014
Pyramid Delaware Merger Subsidiary, Inc.	"PDMS"	Delaware	02/04/2014

YCI, PDMS and DPAC 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 and DPC are the Company's two main operating companies.

DPAC was formed for the purpose of acquiring equity interests of DPC and DPP.

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

TSM was primarily engaged in the marketing of natural gas in Louisiana. As of October 26, 2016 (the date of the Reincorporation Merger and the Davis Merger) and as of December 31, 2016, TSM was dormant due to the limited volumes of natural gas that it marketed, as well as the costs associated with accounting for the entity.

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

PDMS and Davis GOM were inactive during 2017 and PDMS was dissolved on December 29, 2017.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 cash flows associated with oil and gas properties; 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; obligations related to employee benefits such as accrued vacation; 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. Reclassifications include moving COPAS overhead recoveries from lease operating expenses to general and administrative expenses, moving certain other revenue to offset lease operating expense, moving commodity derivative gains (losses) from expenses to other income (expense), and moving regulatory interest from general and administrative to interest expense.

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 10 – Fair Value Measurements).

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable reported on the Consolidated Balance Sheets approximates fair value due to their short-term nature.

The fair value of debt is estimated as the carrying amount of the Company’s credit facility (see Note 10 – Fair Value Measurements).

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

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.

Trade Receivables

The Company’s accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for doubtful accounts, when applicable. The Company establishes provisions for losses on accounts receivable if it determines that collection of all or part of the outstanding balance is doubtful. The Company regularly reviews collectability and establishes or adjusts the allowance for doubtful accounts as necessary using the specific identification method. Accounts receivable are stated net of allowance for doubtful accounts of $934,338 and $1,042,565 at December 31, 2017 and 2016, respectively.

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

Derivative Instruments

The Company periodically enters into derivative contracts to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. All derivatives are recognized on the balance sheet and measured at fair value. The Company does not designate its derivative contracts as hedges, as defined in ASC 815, *Derivatives and Hedging*, and, accordingly, recognizes changes in the fair value of the derivatives currently in earnings (see Note 11 – Commodity Derivative Instruments).

Oil and Natural Gas Properties

Oil and natural gas properties are accounted for using the full cost method of accounting, under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities 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 or gain recognized.

Depreciation, Depletion and Amortization (“DD&A”) – The capitalized cost of oil and natural gas properties, excluding unevaluated properties, is amortized using the unit-of-production method using estimates of proved reserve quantities (equivalent physical units of 6 Mcf of natural gas to each barrel of oil equivalent, or “Boe”). 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 DD&A per Boe for the Company related to oil and natural gas properties was $11.97 and $11.67 for fiscal years 2017 and 2016, respectively. DD&A expense for oil and natural gas properties was $10,724,967 and $7,756,107 for fiscal years 2017 and 2016, respectively.

Impairments – Total capitalized costs of oil and natural gas properties are subject to a limit, or “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 cash flows from estimated production of proved oil and gas reserves, based on current economic and operating conditions; 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 natural gas properties. If unamortized capitalized costs less related deferred income taxes exceed this limit, the excess is charged to impairment 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.

Unproved oil and natural gas properties not subject to amortization consist of undeveloped leaseholds, wells in progress and related capitalized interest. Management reviews the costs of these properties quarterly to determine whether and to what extent developed proved reserves have been assigned to the properties, or if an impairment has occurred, in which case the related costs, along with associated capitalized interest, are reclassified to proved 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 by production, the intent to drill the project or prospect in the future, the economic viability of the development of the project or prospect, the technical evaluation of the project or prospect, as well as the available funds for exploration and development.

Capitalized Interest – Capitalized interest is included as part of the cost of oil and natural gas properties. The Company capitalized $317,691 and $26,121 of interest associated with its line of credit (see Note 15 – Debt and Interest Expense) during fiscal years 2017 and 2016, respectively. The capitalization rates are based on the Company’s weighted average cost of borrowings associated with unproved oil and gas properties not subject to amortization.

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 $1,606,910 and $3,688,642 of allocated indirect costs, excluding interest and direct costs, related to these activities during fiscal years 2017 and 2016, respectively.

The Company develops oil and natural gas drilling projects called “prospects” by industry participants and markets participation in these projects. The Company also assembles 3-D seismic survey projects and markets participating interests in the projects. The proceeds from the sale of the 3-D seismic survey along with the quarterly G&A reimbursements are included in unproved oil and natural gas properties not subject to amortization.

<u>Other Property and Equipment</u>

Other property and equipment is generally recorded at cost, with the exception of the Yuma California properties that were acquired in the Davis Merger, which were recorded at fair value as of the closing date of the Davis Merger in accordance with business combination accounting principles. 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. Depreciation and amortization is calculated using the straight-line method over the estimated useful lives of the respective assets. 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 “Other income (expense)” in the accompanying Consolidated Statements of Operations.

In the event that facts and circumstances indicate that the carrying value of other property and equipment may be impaired, an evaluation of recoverability is performed. If an evaluation is required, the estimated future undiscounted cash flows associated with the asset are compared to the asset’s carrying amount to determine if a write-down to market value (measured using discounted cash flows) is required.

Accounts Payable

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

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 crude oil, natural gas and condensate are delivered to the purchaser and title has transferred. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company’s actual proceeds from the oil and natural gas sold to purchasers. Crude oil sales in Louisiana, representing a significant portion of the Company’s production, are typically indexed to Light Louisiana Sweet (“LLS”). 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.

Sales prices for natural gas and crude oil are adjusted for transportation costs and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas and crude oil, the Company sells the majority of its products soon after production at various locations where title and risk of loss pass to the buyer.

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.
Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax bases of assets and liabilities. A valuation allowance is established to reduce deferred tax assets if it is more likely-than-not that the related tax benefits will not be realized (see Note 17 – Income Taxes).

Other Taxes

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. The Company accrues sales tax on applicable purchases of materials, and remits funds directly to the taxing jurisdictions.

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 2014 Long-Term Incentive Plan effective October 26, 2016, and adopted an Annual Incentive Plan for fiscal years 2017 and 2016 (see Note 13 – Stock-Based Compensation).

The Company grants both liability classified and equity-classified awards including stock options, stock appreciation rights, as well as 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 Company's stock price on the grant date.

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 13 – Stock-Based Compensation).

Other Noncurrent Assets

Noncurrent assets at December 31, 2017 are comprised primarily of deferred debt issuance costs related to the establishment of the new Société Générale ("SocGen") credit facility. Debt issuance costs related to the SocGen credit facility are being amortized to interest expense over the term of the new credit facility, which expires on October 26, 2019, and had a carrying amount of $591,613 at December 31, 2017, of which $336,719 is classified as current other deferred charges and $254,894 is classified as other noncurrent assets. Also included in other noncurrent assets is $15,948 related to the S-3 offering. Amortization expense during the year ended December 31, 2017 and 2016 was $318,103 and $148,970, respectively.

Earnings per Share

The Company's basic earnings per share ("EPS") is computed based on the weighted 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 14 – Net Loss per Common Share).

Treasury Stock

The Company records treasury stock purchases at cost. Amounts are recorded as reductions to stockholders' equity. Shares of common stock are repurchased by the Company as they are surrendered by employees to pay withholding tax upon the vesting of restricted stock awards.

Liquidity

The Company is an exploration and production company with interests in conventional and non-conventional oil and gas properties that require significant investments of capital and time to develop and commence production activities. The Company's primary and potential sources of liquidity include cash on hand, cash from operating activities, borrowings under its revolving credit facility, proceeds from the sales of assets, and potential proceeds from capital market transactions, including the sale of debt and equity securities. As of December 31, 2017, the Company had outstanding borrowings of $27.7 million under its credit facility, and its total borrowing base was $40.5 million, leaving $12.8 million of undrawn borrowing base. In addition, due to the Company's drilling activities as well as other factors, the Company had a working capital deficit of approximately $9.0 million and a loss from operations of $6.8 million as of and for the year ended December 31, 2017.

The Company's plans to mitigate its limited liquidity and the effects of commodity prices on its operations include: closely monitoring capital expenditures planned for 2018 to conserve capital; entering into commodity derivatives for a significant portion of the Company's anticipated production for 2018 (excluding NGL volumes); potentially raising proceeds from capital markets transactions, including the sale of debt or equity securities; and possibly selling certain non-core assets.

The Company's operations are influenced by a number of factors that are beyond its control, including commodity prices, its bank's determination of the Company's borrowing base, normal and unusual production declines, and other factors that could adversely affect the Company's financial positions, results of operations and liquidity.

Recently Issued Accounting Pronouncements

The accounting standard-setting organizations frequently issue new or revised accounting rules. The Company regularly reviews new pronouncements to determine their impact, if any, on the financial statements.

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, "Leases," a new lease standard requiring lessees to recognize lease assets and lease liabilities for most leases classified as operating leases under previous GAAP. The guidance is effective for fiscal years beginning after December 15, 2018 with early adoption permitted. The Company will be required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements. The Company is currently evaluating the impact of the adoption of this standard on its consolidated financial statements, and plans to adopt it no later than January 1, 2019.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments," which provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. This ASU is effective for annual and interim periods beginning after December 15, 2017 and is required to be adopted using a retrospective approach if practicable, with early adoption permitted. The Company will adopt this update, as required, beginning in the first quarter of 2018, and does not expect the adoption to have a material impact on its consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," which assists in determining whether a transaction should be accounted for as an acquisition or disposal of assets or as a business. This ASU is effective for annual and interim periods beginning in 2018 and is required to be adopted using a prospective approach, with early adoption permitted for transactions not previously reported in issued financial statements. The Company adopted this ASU on January 1, 2017, and expects that the adoption of this ASU could have a material impact on future consolidated financial statements, as future oil and gas asset acquisitions may not be considered businesses.

In March 2016, the FASB issued ASU 2016-09, "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting," which simplifies the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows, and accounting for forfeitures. This ASU is effective for annual and interim periods beginning after December 15, 2017. The Company adopted this ASU on January 1, 2017. The adoption of this standard did not have a material impact on the Company's consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers," which will supersede most of the existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which it expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures that are sufficient to enable users to understand an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This update provides clarifications in the assessment of principal versus agent considerations in the new revenue standard. In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow Scope Improvements and Practical Expedients. The update reduces the potential for diversity in practice at initial application of Topic 606 and the cost and complexity of applying Topic 606. In December 2016, the FASB issued ASU 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers. The update was issued to increase stakeholders' awareness of the proposals for technical corrections and to expedite improvements. These ASUs are effective for annual and interim periods beginning after December 15, 2017. The Company adopted these standards effective January 1, 2018 using the full retrospective method. The Company finalized the detailed analysis of the impact of the standard on its contracts. The Company found that there was no significant impact on its financial position or results of operations. Upon adoption of these standards, the Company will not be required to record a cumulative effect adjustment due to the new standards not having a quantitative impact compared to existing GAAP. Also, upon adoption of these standards, the Company will not be required to alter its existing information technology and internal controls outside of ongoing contract review processes in order to identify impacts of future revenue contracts entered into by the Company. The Company does not anticipate the disclosure requirements under the standards to have a material change on how it presents information regarding its revenue streams as compared to existing GAAP.

NOTE 3 – PREPAYMENTS

At December 31, prepayments consisted of the following:

	December 31, 2017	December 31, 2016
Prepaid insurance	$ 828,648	$ 817,268
Prepaid taxes	28,158	97,934
Other prepayments	119,656	148,216
Total prepayments	$ 976,462	$ 1,063,418

NOTE 4 - ACQUISITIONS AND DIVESTMENTS

Divestments

During 2017, the Company made the following divestments:

- El Halcón – The Company sold certain oil and natural gas properties for $5.5 million gross located in Brazos County, Texas known as the El Halcón property. The El Halcón property consisted of an average working interest of approximately 8.5% (1,557 net acres).
- Cat Canyon – In May 2017, the Company sold all of its interest in 149 acres located in Santa Barbara County, California, to Texican Energy Corporation for $165,000, along with the assumption of plugging and abandonment obligations for three of four wells on the property.
- Mario – In December 2017, the Company sold a 12.5% working interest in ten sections of the project in Yoakum County, Texas, known as Mario, for $500,000, which is recorded at December 31, 2017 in “Other receivables” in the accompanying Consolidated Balance Sheets.

During 2016, the Company made the following divestments:

- Clipper – the Company relinquished its right to a 5% reversionary interest for zero consideration.
- Masters Creek – the Company assigned its interest in 27 gross wells in exchange for P&A liability.
- California – the Company sold surface rights to 77 acres for $1,140,427.

Davis Merger

On October 26, 2016, pursuant to the Reincorporation Merger, Yuma California was reincorporated in Delaware as YEI. Also on October 26, 2016, YEI and Davis closed the Davis Merger. In this transaction, YEI acquired all of the outstanding common stock and preferred stock of Davis, through a newly formed subsidiary, with Davis surviving as a wholly owned subsidiary of YEI, issuing approximately 7.45 million shares of common stock to holders of Davis common stock and approximately 1.75 million shares of Series D Preferred Stock to existing Davis preferred stockholders. The Davis Merger resulted in a change of control of YEI. The Davis Merger was recorded in accordance with ASC 805 as a reverse acquisition whereby Davis was considered the acquirer for accounting purposes although YEI was the acquirer for legal purposes. ASC 805 also requires that, among other things, YEI’s assets acquired and liabilities assumed be measured at their acquisition date fair values. The results of operations from YEI’s legacy assets are reflected in the Company’s Consolidated Statements of Operations beginning October 26, 2016.

An allocation of the purchase price was prepared using, among other things, the Company’s December 31, 2015 reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), an independent petroleum engineering firm, and adjusted by the Company’s reserve engineering staff to the October 26, 2016 acquisition date.

The fair value of the consideration transferred, assets acquired, and liabilities assumed are described below (in thousands):

Purchase Consideration	
Common stock (1)	$ 20,883
Stock appreciation rights (2)	85
Stock options (3)	1
Restricted stock awards (4)	181
Restricted stock units (5)	-
Debt (6)	30,202
Net purchase considered to be allocated	$ 51,352
Estimated fair value of assets acquired	
Proved natural gas and oil properties	$ 54,974
Unproved natural gas and oil properties	505
Real property	2,755
Personal property	1,427
Commodity derivatives - asset	1,195
Deposits	414
Other assets	485
Other long-term assets	2
Total assets acquired	61,757
Estimated fair value of liabilities acquired	
Net working capital	(4,453)
Asset retirement obligation	(5,874)
Commodity derivatives - liabilities	(78)
Total liabilities acquired	(10,405)
Total assets and liabilities acquired	$ 51,352

(1) 4,746,180 shares of Yuma California Common Stock were effectively transferred in connection with the Davis Merger. Those shares were valued at $4.40 per share, which was the last sales price of Yuma California Common Stock at October 26, 2016. The October 26, 2016 share price used is the same date as the October 26, 2016 NYMEX strip price that was applied in Yuma California's engineering reports.
(2) Yuma California's stock appreciation rights were valued using the binomial lattice model.
(3) Yuma California's 5,000 stock options were valued at approximately $0.259 per option using the Black-Scholes model.
(4) 901 restricted stock awards vested in 2016 and the 78,336 restricted stock awards vesting in 2017 and 2018 were valued at $4.40 per share on October 26, 2016.
(5) Yuma California had no restricted stock units outstanding at October 26, 2016.
(6) Debt fair value approximates the related book value at October 26, 2016.

The following unaudited pro forma combined results of operations are provided for the years ended December 31, 2016 and 2015 as though the Davis Merger had been completed as of the beginning of the earliest period presented, or January 1, 2015. These pro forma combined results of operations have been prepared by adjusting the historical results of the Company to include the historical results of Yuma California. 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 Davis Merger or any estimated costs that will be incurred to integrate Davis and Yuma California. 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.

($ in thousands)	Years Ended December 31, 2016 (Unaudited)	Years Ended December 31, 2015 (Unaudited)
Revenues	$ 24,536	$ 45,813
Net loss	$ (41,829)	$ (70,884)
Net loss per share:		
Basic	$ (3.43)	$ (5.80)
Diluted	$ (3.43)	$ (5.80)

NOTE 5 – ASSET IMPAIRMENTS

Capitalized costs (net of accumulated DD&A and deferred income taxes) of proved oil and natural gas properties subject to amortization are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves and estimated related future income taxes. The oil and natural gas prices used to calculate the full cost ceiling were $51.34/Bbl for oil and $2.98/MMBtu for natural gas. In accordance with SEC rules, these prices are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are adjusted for “basis” or location differentials. Prices are held constant over the life of the reserves. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling. During the year ended December 31, 2016, the Company recorded a full cost ceiling impairment $20.7 million due to the low commodity prices and a reduction of the Company’s proved undeveloped reserves. No impairment was recorded during the year ended December 31, 2017.

NOTE 6 – PROPERTY, PLANT, AND EQUIPMENT, NET

Oil and Gas Properties

The following table sets forth the capitalized costs and associated accumulated depreciation, depletion and amortization (including impairments), relating to the Company’s oil and natural gas properties at December 31:

	December 31, 2017	December 31, 2016
Subject to amortization (proved properties)	$ 494,216,531	$ 488,723,905
Less: Accumulated depreciation, depletion,		
and amortization	(421,165,400)	(410,440,433)
Proved properties, net	$ 73,051,131	$ 78,283,472
Not subject to amortization (unproved properties)		
Leasehold acquisition costs	3,133,162	2,411,402
Exploration and development	3,368,339	1,219,466
Capitalized Interest	292,871	26,121
Total unproved properties	6,794,372	3,656,989
Oil and gas properties, net	$ 79,845,503	$ 81,940,461

Unproved properties not subject to amortization

Costs not being amortized are transferred to the Company's proved properties subject to amortization as its drilling program is executed or costs are evaluated and deemed impaired. The Company anticipates that these unevaluated costs will be included in the depletion computation in 2018 and 2019. A summary of the Company's reported value of unproved properties not subject to amortization by year incurred is as follows:

	Year Incurred		
	2017	2016 and prior	Total
Leasehold acquisition costs	$ 2,810,874	$ 322,288	$ 3,133,162
Exploration and development	3,368,339	-	3,368,339
Capitalized interest	131,357	161,514	292,871
Total	$ 6,310,570	$ 483,802	$ 6,794,372

Other

Other property and equipment consists of the following:

	Estimated useful life in years	December 31, 2017	December 31, 2016
Plants and pipeline systems	10	$ -	$ 4,218,496
Land	n/a	1,314,000	1,314,000
Software and IT equipment	3 - 5	979,389	964,581
Drilling and operating equipment	15	837,013	841,494
Furniture and fixtures	7 - 10	712,692	820,584
Buildings	25	286,000	286,000
Automobiles	3 - 7	232,105	207,115
Office leasehold improvements	10	84,260	84,260
Total other property and equipment		4,445,459	8,736,530
Less: Accumulated depreciation and leasehold improvement amortization		(1,409,535)	(5,349,145)
Net book value		$ 3,035,924	$ 3,387,385

Depreciation and leasehold improvement amortization expense related to other property and equipment outside of oil and natural gas properties totaled $230,236 and $483,695 for the years ended December 31, 2017 and 2016, respectively, and is included on the Consolidated Statements of Operations in Depreciation, depletion and amortization.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations ("AROs") represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. Revisions in estimated liabilities during the period relate primarily to changes in estimates of timing. Revisions in estimated liabilities can also include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected asset retirement costs. The changes in the asset retirement obligations for the years ended December 31, 2017 and 2016 were as follows:

	December 31, 2017	December 31, 2016
Beginning of year balance	$ 10,196,383	$ 5,332,050
Liabilities assumed in the merger	-	5,873,504
Liabilities incurred during year	6,663	277,876
Liabilities settled during year	(389,765)	(572,623)
Liabilities sold during year	(418,527)	(1,334,215)
Accretion expense	557,683	254,573
Revisions in estimated cash flows	513,976	365,218
End of year balance	$ 10,466,413	$ 10,196,383

Liabilities sold during 2017 include the sale of the El Halcón properties. Liabilities settled include plugging and abandoning four gross wells in the Masters Creek Field and one well in the Cat Canyon Field.

NOTE 8 – ACCOUNTS RECEIVABLE FROM CHIEF EXECUTIVE OFFICER AND EMPLOYEES

The following table provides information with respect to related party transactions with the Chief Executive Officer ("CEO") of the Company and employees. The receivable from the CEO is primarily for invoiced costs on prospects and wells as part of his normal joint interest billings (see Note 9 – Related Party Transactions).

	December 31, 2017	December 31, 2016
Receivables from CEO and employees:		
Current:		
CEO	$ 53,979	$ 67,114
Employees	-	900
Total	$ 53,979	$ 68,014

NOTE 9 – RELATED PARTY TRANSACTIONS

In 2011, Yuma California entered into a Working Interest Incentive Plan ("WIIP") with Mr. Sam L. Banks, the CEO of Yuma California and the Company.

The Board of Directors of Yuma California terminated the WIIP effective September 21, 2015; however, Mr. Banks retains working interests in certain of the Company's properties resulting from prior purchases under the WIIP.

NOTE 10 – 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 2 – 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.

	Fair value measurements at December 31, 2017			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
Liabilities:				
Commodity derivatives – oil	$ -	$ 1,517,410	$ -	$ 1,517,410
Commodity derivatives – gas	-	(278,001)	-	$ (278,001)
Total liabilities	$ -	$ 1,239,409	$ -	$ 1,239,409

	Fair value measurements at December 31, 2016			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
Liabilities:				
Commodity derivatives – oil	$ -	$ 956,997	$ -	$ 956,997
Commodity derivatives – gas	-	1,599,005	-	$ 1,599,005
Total liabilities	$ -	$ 2,556,002	$ -	$ 2,556,002

Derivative instruments listed above include swaps, collars, and three-way collars (see Note 11 – Commodity Derivative Instruments).

Debt – The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheets (see Note 15 – 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 AROs 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 7 – Asset Retirement Obligations).

NOTE 11 – COMMODITY DERIVATIVE INSTRUMENTS

Objectives 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.

Counterparty Credit Risk – Commodity derivative instruments expose the Company to counterparty credit risk. The Company's commodity derivative instruments are with SocGen and BP Energy Company ("BP"), both of which are rated "A" by Standard and Poor's and "A2" by Moody's. 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.

Commodity derivative instruments open as of December 31, 2017 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").

	2018 Settlement	2019 Settlement (1)
NATURAL GAS (MMBtu):		
Swaps		
Volume	1,725,133	373,906
Price	$ 3.00	$ 3.00
CRUDE OIL (Bbls):		
Swaps		
Volume	195,152	156,320
Price	$ 53.17	$ 53.77

(1) Represents volumes through March 2019.

Derivatives for each commodity are netted on the Consolidated Balance Sheets. 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,	
	2017	2016
Asset commodity derivatives:		
Current assets	$ 295,304	$ 734,464
Noncurrent assets	118	54,380
	295,422	788,844
Liability commodity derivatives:		
Current liabilities	(1,198,307)	(2,074,915)
Noncurrent liabilities	(336,524)	(1,269,931)
	(1,534,831)	(3,344,846)
Total commodity derivative instruments	$ (1,239,409)	$ (2,556,002)

Net gains (losses) from commodity derivatives on the Consolidated Statements of Operations are comprised of the following:

	Years Ended December 31,	
	2017	2016
Derivative settlements	$ 1,238,341	$ 1,607,365
Mark to market on commodity derivatives	1,316,593	(5,382,619)
Net gains (losses) from commodity derivatives	$ 2,554,934	$ (3,775,254)

NOTE 12 – PREFERRED STOCK

On March 8, 2013, Davis issued 27,442,727 shares of Series A Convertible Preferred Stock ("Series A Preferred Stock") providing for cumulative dividends of 7.0% per annum, payable in-kind, for approximately $15.1 million in proceeds. Proceeds from the issuance of the Series A Preferred Stock, along with $14.0 million in borrowings under its senior credit facility and available cash were used to purchase 65,672,512 shares of Davis' common stock in March 2013. From January 1, 2016 through October 26, 2016, and during 2015, Davis issued 1,952,801 and 2,236,986 shares of Series A Preferred Stock, respectively, as paid in-kind dividends and as of October 26, 2016 immediately prior to the completion of the Davis Merger, there were 35,319,988 shares of Series A Preferred Stock outstanding.

As part of the closing of the Davis Merger, each share of Series A Preferred Stock was converted into 0.04966536 shares of Series D Preferred Stock of the Company. The Company issued an aggregate of 1,754,179 shares of Series D Preferred Stock as part of the completion of the Davis Merger to former holders of Series A Preferred Stock, which is convertible into shares of the Company's common stock. Each share of Series D Preferred Stock is convertible into a number of shares of common stock determined by dividing the original issue price, which was $11.0741176, by the conversion price, which is currently $6.5838109 due to the Company's common stock offering in September and October of 2017. The conversion price is subject to adjustment for stock splits, stock dividends, reclassification, and certain issuances of common stock for less than the conversion price. As of December 31, 2017, the Series D Preferred Stock had a liquidation preference of approximately $21.1 million. The Series D Preferred Stock provides for cumulative dividends of 7.0% per annum, payable in-kind. The Company issued 127,673 shares of Series D Preferred Stock during the year ended December 31, 2017.

NOTE 13 – STOCK-BASED COMPENSATION

2006 Stock Incentive Plan

On October 26, 2016, the Company assumed the Yuma California 2006 Equity Incentive Plan ("2006 Plan"). The 2006 Plan provided, among other things, for the granting of stock options to key employees, officers, directors, and consultants of Yuma California by its board of directors. As of the closing of the Reincorporation Merger, there were stock option awards for 5,000 shares of common stock outstanding that were assumed by the Company. Further, on September 11, 2014, the board of directors of Yuma California determined that no additional awards would be granted under the 2006 Plan, and that the 2014 Plan would be used going forward.

2011 Stock Option Plan

On October 26, 2016, the Company assumed the Yuma California 2011 Stock Option Plan ("2011 Plan"). The 2011 Plan provided, among other things, for the granting of up to 227,201 shares of common stock as awards to key employees, officers, directors, and consultants of Yuma California by its board of directors. An award could take the form of stock options, stock appreciation rights, restricted stock awards or restricted stock units. As of the closing of the Reincorporation Merger, there were awards for approximately 2,878 shares of common stock outstanding that were assumed by the Company. Further, on September 11, 2014, the board of directors of Yuma California determined that no additional awards would be granted under the 2011 Plan, and that the 2014 Plan would be used going forward.

2014 Long-Term Incentive Plan

On October 26, 2016, the Company assumed the Yuma California 2014 Long-Term Incentive Plan (the "2014 Plan"), which was approved by the shareholders of Yuma California. The shareholders of Yuma California originally approved the 2014 Plan at the special meeting of shareholders on September 10, 2014 and the subsequent amendment to the 2014 Plan at the special meeting of shareholders on October 26, 2016. Under the 2014 Plan, YEI may grant stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, performance bonuses, stock awards and other incentive awards to employees of YEI and its subsidiaries and affiliates. YEI may also grant nonqualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, stock awards and other incentive awards to any persons rendering consulting or advisory services and non-employee directors of YEI and its subsidiaries, 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 2,495,000 shares of common stock may be issued in conjunction with awards granted under the 2014 Plan. As of the closing of the Reincorporation Merger, there were awards for approximately 179,165 shares of common stock outstanding that were assumed by the Company. 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.

At December 31, 2017, 930,916 shares of the 2,495,000 shares of 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. The Company accrued $1.1 million of stock-based compensation expense in 2017 for RSAs awarded in 2018 that related to 2017 annual incentive bonuses.

Davis Management Incentive Plan

Davis had the Davis Petroleum Acquisition Corp. Management Incentive Plan (the "Davis Plan") that was terminated as part of the closing of the Davis Merger and all outstanding stock options were cancelled or exchanged for Davis common stock prior to the closing of the Davis Merger and all outstanding restricted stock awards under the Davis Plan were vested or forfeited prior to the closing of the Davis Merger.

Restricted Stock – The Company assumed restricted stock awards ("RSAs") issued under the 2011 Plan and the 2014 Plan in 2014, 2015 and 2016 as part of the Davis Merger. These RSAs were valued at the time of the Davis Merger at fair value, which was the Company's stock price on October 26, 2016 of $4.40 per share. These RSAs 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.

A summary of the status of the RSAs for employees and non-employee directors and changes for the year to date ended December 31, 2017 is presented below.

	Number of unvested RSA shares	Weighted average grant-date fair value
Unvested shares as of January 1, 2017	78,336	$4.40 per share
Vested on January 3, 2017	(10,481)	$4.40 per share
Granted on April 20, 2017	329,491	$2.56 per share
Vested on April 20, 2017	(21,310)	$2.56 per share
Vested on May 31, 2017	(31,148)	$4.40 per share
Vested on June 30, 2017	(21,305)	$2.56 per share
Vested on July 20, 2017	(1,250)	$4.40 per share
Vested on September 29, 2017	(21,305)	$2.56 per share
Vested on October 16, 2017	(2,437)	$4.40 per share
Vested on November 1, 2017	(623)	$4.40 per share
Vested on December 29, 2017	(21,305)	$2.56 per share
Forfeited	(2,213)	$2.56 per share
Unvested shares as of December 31, 2017	274,450	$2.78 per share

At December 31, 2017, total unrecognized RSA compensation cost of $460,400 is expected to be recognized over a weighted average remaining service period of approximately two years.

Stock Appreciation Rights – Stock Settled – On October 26, 2016, in connection with the closing of the Davis Merger, the Company assumed outstanding Stock Appreciation Rights ("SARs") granted under the 2014 Plan, as follows:

	Number of unvested SARs	Weighted average grant-date fair value
Unvested shares as of January 1, 2017	56,165	$2.35 per share
Vested on May 31, 2017	(28,084)	$2.35 per share
Forfeited	-	
Unvested shares as of December 31, 2017	28,081	$2.35 per share

Assumptions used to estimate fair value of the above SARs assumed were expected life of 5.8 years, 84.2% volatility, 1.42% risk-free rate, and zero annual dividends.

At December 31, 2017, total unrecognized SAR compensation cost of $27,118 is expected to be recognized over a weighted average remaining service period of approximately five months.

The SARs in the table above have a weighted average exercise price of $12.10 and an aggregate intrinsic value of zero. The Company intends to settle these SARs in equity, as opposed to cash.

Stock Appreciation Rights – Cash Settled – On April 20, 2017, the Company granted SARs that are settled in cash under the 2014 Plan, as follows:

	Number of unvested SARs	Weighted average fair value
Unvested shares as of January 1, 2017	-	
Granted on April 20, 2017	1,623,371	$0.66 per share
Vested	-	
Forfeited	-	
Unvested shares as of December 31, 2017	1,623,371	$0.66 per share

The cash settled SARs vest under the same terms and conditions as stock options; however, they are settled in cash equal to their settlement date fair value. As a result, the cash settled SARs are recorded in the Company's consolidated balance sheets as a liability until the date of exercise. The fair value of each SAR award is estimated using an option pricing model. In accordance with ASC Topic 718, "Stock Compensation," the fair value of each SAR award is recalculated at the end of each reporting period and the liability and expense adjusted based on the new fair value and the percent vested. The Company did not grant any cash settled SARs during 2016. The assumptions used to determine the fair value of the cash settled SAR awards at December 31, 2017 were expected life of 3.8 years, 117.7% volatility, 2.05% risk-free rate, and zero annual dividends.

Stock Options – Davis issued stock options under the Davis Petroleum Acquisition Corp. Management Incentive Plan (the "Davis Plan") to its employees. During 2016, all of the outstanding stock options granted under the Davis Plan (the "Davis Options") were either cancelled or exercised.

The Company assumed stock options issued by Yuma California as compensation to non-employee directors under the 2006 Plan. The options vested immediately, and are exercisable for a five-year period from the date of the grant.

During 2017, the Company granted stock options under the 2014 Plan. The options vest in three equal annual installments beginning on February 6, 2018 and after vesting are exercisable until the tenth anniversary of the grant date.

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, 2016	5,000	$ 103.20	0.77	$ -
Granted	893,617	$ 2.56	9.30	-
Exercised	-	-	-	-
Forfeited	-	-	-	-
Assumed	-	-	-	-
Outstanding at December 31, 2017	898,617	$ 3.12	9.25	$ -
Vested at December 31, 2017	5,000	$ 103.20	0.77	$ -
Exercisable at December 31, 2017	5,000	$ 103.20	0.77	$ -

The Company uses the Black-Scholes option pricing model to calculate the fair value of its stock options. Assumptions used to estimate fair values for the options assumed were expected life of two years, 115.5% volatility, 0.85% risk-free rate, and zero annual dividends; for options granted, assumptions used were expected life of 5.9 years, 84.2% volatility, 1.9% risk-free rate, and zero annual dividends.

As of December 31, 2017, there were 893,617 unvested stock options and $1,151,440 unrecognized stock option expenses, with a weighted average remaining service period of 2.1 years.

Total share-based compensation expense recognized for the years ended December 31, 2017 and 2016 was $2,381,365 and $1,731,969, respectively, and is reflected in general and administrative expenses in the Consolidated Statements of Operations. These amounts are net of share-based compensation capitalized to the full cost pool for the years ended December 31, 2017 and 2016 of $-0- and $1,717,698, respectively.

NOTE 14 – NET LOSS PER COMMON SHARE

Net loss per common share – Basic is calculated by dividing net loss by the weighted average number of shares of common stock outstanding during the period. Net loss per common share – Diluted assumes the conversion of all potentially dilutive securities, and is calculated by dividing net loss by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Net loss per common share – Diluted considers the impact of potentially dilutive securities except in periods where their inclusion would have an anti-dilutive effect. Equity, including the average number of shares of common stock and per share amounts, has been retroactively restated to reflect the Davis Merger.

A reconciliation of loss per common share is as follows:

	Years Ended December 31,	
	2017	2016
Net loss attributable to common stockholders	$ (6,806,633)	$ (42,651,060)
Net loss per common share:		
Basic	$ (0.46)	$ (5.13)
Diluted	$ (0.46)	$ (5.13)
Weighted average common shares outstanding		
Basic	14,815,991	8,317,777
Add potentially dilutive securities:		
Unvested restricted stock awards	-	-
Stock appreciation rights	-	-
Stock options	-	-
Series D preferred stock	-	-
Diluted weighted average common shares outstanding	14,815,991	8,317,777

For the year ended December 31, 2017, the Company excluded 274,450 shares of unvested restricted stock awards, 1,707,619 stock appreciation rights, 898,617 stock options, and 1,904,391 shares of Series D Preferred Stock in calculating diluted earnings per share, as the effect was anti-dilutive. For the year ended December 31, 2016, the Company excluded 78,336 shares of unvested restricted stock awards, 84,248 stock appreciation rights, 5,000 stock options, and 1,776,718 shares of Series D Preferred Stock in calculating diluted earnings per share, as the effect was anti-dilutive.

NOTE 15 – DEBT AND INTEREST EXPENSE

Long-term debt at December 31 consisted of the following:

	December 31, 2017	December 31, 2016
Senior credit facility	$ 27,700,000	$ 39,500,000
Installment loan due 7/22/18 originating from the financing of insurance premiums at 5.14% interest rate	651,124	-
Installment loan due 7/15/17 originating from the financing of insurance premiums at 4.38% interest rate	-	599,341
Total debt	28,351,124	40,099,341
Less: current maturities	(651,124)	(599,341)
Total long-term debt	$ 27,700,000	$ 39,500,000

Senior Credit Facility

In December 2008, Davis amended and restated its senior credit agreement (the "senior credit facility") with a financial institution. The senior credit facility was subsequently amended in April 2011, January 2013, January 2016 and September 2016. The senior credit facility was paid off as part of the closing of the Davis Merger and the Company subsequently entered into the Credit Agreement (discussed below).

In connection with the closing of the Davis Merger, on October 26, 2016, YEI and three of its subsidiaries, as the co-borrowers, entered into a Credit Agreement providing for a $75.0 million three-year senior secured revolving credit facility (the "Credit Agreement") with SocGen, as administrative agent, SG Americas Securities, LLC, as lead arranger and bookrunner, and the Lenders signatory thereto (collectively with SocGen, the "Lender").

As of December 31, 2017, the credit facility had a borrowing base of $40.5 million which was reaffirmed as of September 8, 2017. The Credit Agreement governing the Company's credit facility provides for interest-only payments until October 26, 2019, when the Credit Agreement matures and any outstanding borrowings are due. The borrowing base under the Company's Credit Agreement is subject to redetermination on April 1st and October 1 st 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.

The Company's obligations under the Credit Agreement are guaranteed by its subsidiaries and are secured by liens on substantially all of the Company's assets, including a mortgage lien on oil and natural gas properties covering at least 95% of the PV10 value of the proved oil and gas properties included in the determination of the borrowing base.

The amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus 3.00% to 4.00% or (b) the prime lending rate of SocGen plus 2.00% to 3.00%, depending on the amount borrowed under the credit facility and whether the loan is drawn in U.S. dollars or Euro dollars. The interest rate for the credit facility at December 31, 2017 was 5.07% for LIBOR-based debt and 7.00% for prime-based debt. Principal amounts outstanding under the credit facility are due and payable in full at maturity on October 26, 2019. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of the Company's assets. Additional payments due under the Credit Agreement include paying a commitment fee to the Lender in respect of the unutilized commitments thereunder. The commitment rate is 0.50% per year of the unutilized portion of the borrowing base in effect from time to time. The Company is also required to pay customary letter of credit fees.

In addition, the Credit Agreement requires the Company to maintain the following financial covenants: a current ratio of not less than 1.0 to 1.0 on the last day of each quarter, a ratio of total debt to earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses ("EBITDAX") ratio of not greater than 3.5 to 1.0 for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding such date of determination, and a ratio of EBITDAX to interest expense of not less than 2.75 to 1.0 for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding such date of determination, and cash and cash equivalent investments together with borrowing availability under the Credit Agreement of at least $4.0 million. The Credit Agreement contains customary affirmative covenants and defines events of default for credit facilities of this type, including failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default, and a change of control. Upon the occurrence and continuance of an event of default, the Lender has the right to accelerate repayment of the loans and exercise its remedies with respect to the collateral. As of December 31, 2017, the Company was in compliance with the financial covenants under the Credit Agreement.

The Company incurred commitment fees of $41,404 and $22,855 during 2017 and 2016, respectively.

NOTE 16 – STOCKHOLDERS' EQUITY

The Company is authorized to issue up to 100,000,000 shares of common stock, $0.001 par value per share, and 20,000,000 shares of preferred stock, $0.001 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. The Company has designated 7,000,000 shares of preferred stock as Series D Preferred Stock.

The Company assumed the 2006 Plan, the 2011 Plan, and the 2014 Plan upon the completion of the Reincorporation Merger as described in Note 13 – Stock-Based Compensation, which describes outstanding stock options, restricted stock awards and stock appreciation rights granted under the 2006 Plan, the 2011 Plan and the 2014 Plan.

In September and October 2017, the Company completed a public offering of 10,100,000 shares of common stock (including 500,000 shares purchased pursuant to the underwriter's overallotment option), at a public offering price of $1.00 per share. The Company received net proceeds from this offering of approximately $8.7 million, after deducting underwriters' fees and offering expenses of $1.4 million.

NOTE 17 – INCOME TAXES

The provision for income taxes for the years ended December 31 is as follows:

	December 31, 2017	December 31, 2016
Current expense (benefit)		
Federal	$ -	$ -
State	-	-
Deferred expense (benefit)		
Federal	-	-
State	-	1,425,964
Total income tax expense	$ -	$ 1,425,964

A reconciliation of the federal statutory income tax rate to the effective income tax rate for the years ended December 31 is as follows:

	December 31,	
	2017	2016
U.S. statutory rate	35.00%	35.00%
State income taxes (net of federal benefit)	(9.21%)	(3.55%)
Nondeductible transaction costs	(1.61%)	(2.84%)
Stock compensation	(0.03%)	(4.07%)
Prior year differences	7.38%	0.00%
Change in tax rates	(429.43%)	0.00%
Valuation allowance	397.96%	(28.08%)
Other	(0.06%)	(0.01%)
Effective tax rate	0.00%	(3.55%)

Deferred income tax (liabilities) assets at December 31 follow:

	December 31,	
	2017	2016
Deferred income tax liabilities		
Other property and equipment	$ (4,599,347)	$ -
	(4,599,347)	-
Deferred income tax assets		
Net operating loss carryforward	41,368,982	52,258,483
Commodity derivative instruments	326,893	1,013,175
Financial accruals and other	246,001	982,544
Asset retirement obligation	2,476,370	3,916,319
Other property and equipment	-	3,353,922
Stock-based compensation	270,366	26,051
Valuation allowance	(40,089,265)	(61,550,494)
	4,599,347	-
Deferred income taxes, net	$ -	$ -

At December 31, 2017, the Company had federal and state net operating loss carryforwards of approximately $169.7 million which expire between 2022 and 2037. Of this amount, approximately $59.5 million is subject to limitation under Section 382 of the Code, which could result in a significant portion of the $59.5 million expiring prior to being utilized. Realization of a deferred tax asset is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carryforwards. At December 31, 2017, the Company has recorded a full valuation allowance against its federal and state net deferred tax assets of $40.1 million because the Company believes it is more likely than not that the assets will not be utilized based on losses over the most recent three-year period. At December 31, 2017, the Company does not have any unrecognized tax benefits and does not anticipate any unrecognized tax benefits during the next twelve months. The tax years of the Company that remain subject to examination by the Internal Revenue Service and other income tax authorities are fiscal years 2013 to 2017.

Recently Enacted U.S. Tax Legislation

Comprehensive tax reform legislation enacted in December 2017, the Tax Cuts and Jobs Act (the “Tax Act”), makes significant changes to U.S. federal income tax laws. The Tax Act, among other things, reduces the corporate income tax rate from 35% to 21%, partially limits the deductibility of future net operating losses, and allows for the immediate deduction of certain new investments instead of deductions for depreciation expense over time. Although the Company has estimated the impact of the newly enacted tax legislation by incorporating assumptions based upon its current interpretation and analysis to date, the Tax Act is complex and far reaching, and the Company has not completed its analysis of the actual impact of its enactment. There may be other material adverse effects resulting from the Tax Act that the Company has not identified and that could have an adverse effect on its business, results of operations, financial condition and cash flow. The main effect of the Tax Act on the Company is the re-measurement of the deferred tax assets and liabilities from 35% to 21%, which resulted in an impact to the effective tax rate of (429.43%). Since the Company is in a full valuation allowance, no income tax expense or benefit has been recorded in connection with the re-measurement of the deferred tax assets and liabilities. The results of the re-measurement are offset with a corresponding change in the valuation allowance. The Company will continue to evaluate the Tax Act and adjust the provisional amounts as additional information is obtained. The ultimate impact of the Tax Act may differ from the provisional amounts recorded due to additional information becoming available, changes in interpretation of the Tax Act, and additional regulatory guidance that may be issued.

NOTE 18 – COMMITMENTS AND CONTINGENCIES

Joint Development Agreement

On March 27, 2017, the Company entered into a Joint Development Agreement ("JDA") with two privately held companies, both unaffiliated entities, covering an area of approximately 52 square miles (33,280 acres) in the Permian Basin of Yoakum County, Texas. In connection with the JDA, the Company held a 75% working interest in approximately 3,669 acres (2,752 net acres) as of December 31, 2017. As the operator of the property covered by the JDA, the Company was committed as of December 31, 2017 to spend an additional $984,068 by March 2020. The Company intends to acquire additional leasehold acreage and continue drilling joint venture wells in 2018 (see Note 22 – Subsequent Events).

Throughput Commitment Agreement

On August 1, 2014, Crimson Energy Partners IV, LLC, as operator of the Company's Chalktown properties, in which the Company has a working interest, entered into a throughput commitment (the "Commitment") with ETC Texas Pipeline, Ltd. effective April 1, 2015 for a five year throughput commitment. In connection with the Commitment, the operator and the Company failed to reach the volume commitments in year two, and the Company anticipates that a shortfall will exist through the expiration of the five year term, which expires in March 2020. Accordingly, the Company is accruing the expected volume commitment shortfall amounts based on production to lease operating expense ("LOE") on a monthly basis. On a net basis, the Company anticipates accruing approximately $30,000 in LOE per month, which represents the maximum amounts that could be owed based upon the Commitment.

Lease Agreements

On July 26, 2017, the Company entered into a tenth amendment to its office lease whereby the term of the lease was extended to August 31, 2023. The lease amendment covers a period of 68 calendar months and went into effect on January 1, 2018. In addition, the lease amendment included seven months of abated rent and operating expenses from June 1, 2017 through February 1, 2018, as well as other incentives, including abated parking cost and tenant lease improvement allowances. The base rent amount (which began on January 1, 2018) starts at $258,060 per annum and escalates to $288,420 per annum during the final 19 months of the lease extension. In addition to the base rent amount, the Company will also be responsible for additional operating expenses of the building as well as parking charges once the abatement period ends. The Company accounts for the lease as an operating lease under GAAP.

The Company also 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, 2020.

Aggregate rental expense for the years ended December 31, 2017 and 2016 was $507,331 and $546,272, respectively. As of December 31, 2017, future minimum base rentals (including estimated operating expenses) under all noncancellable operating leases are as follows:

2018	$	486,805
2019	$	534,294
2020	$	522,850
2021	$	529,574
2022	$	536,790
2023	$	358,282

Certain Legal Proceedings

From time to time, the Company is party to various legal proceedings arising in the ordinary course of business. The Company expenses or accrues legal costs as incurred. A summary of the Company's legal proceedings is as follows:

Yuma Energy, Inc. v. Cardno PPI Technology Services, LLC Arbitration

On May 20, 2015, counsel for Cardno PPI Technology Services, LLC ("Cardno PPI") sent a notice of the filing of liens totaling $304,209 on the Company's Crosby 14 No. 1 Well and Crosby 14 SWD No. 1 Well in Vernon Parish, Louisiana. The Company disputed the validity of the liens and of the underlying invoices, and notified Cardno PPI that applicable credits had not been applied. The Company invoked mediation on August 11, 2015 on the issues of the validity of the liens, the amount due pursuant to terms of the parties' Master Service Agreement ("MSA"), and PPI Cardno's breaches of the MSA. Mediation was held on April 12, 2016; no settlement was reached.

On May 12, 2016, Cardno filed a lawsuit in Louisiana state court to enforce the liens; the Court entered an Order Staying Proceeding on June 13, 2016, ordering that the lawsuit "be stayed pending mediation/arbitration between the parties." On June 17, 2016, the Company served a Notice of Arbitration on Cardno PPI, stating claims for breach of the MSA billing and warranty provisions. On July 15, 2016, Cardno PPI served a Counterclaim for $304,209 plus attorneys' fees. The parties selected an arbitrator, and the initial arbitration hearing was held on March 29, 2018. The arbitration has been continued, with the next hearing to be held on April 12 and 13, 2018. Management intends to pursue the Company's claims and to defend the counterclaim vigorously. 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 consolidated financial statements.

The Parish of St. Bernard v. Atlantic Richfield Co., et al

On October 13, 2016, two subsidiaries of the Company, Exploration and Yuma Petroleum Company ("YPC"), were named as defendants, among several other defendants, in an action by the Parish of St. Bernard in the Thirty-Fourth Judicial District of Louisiana. The petition alleges violations of the State and Local Coastal Resources Management Act of 1978, as amended, in the St. Bernard Parish. The Company has notified its insurance carrier of the lawsuit. Management intends to defend the plaintiffs' claims vigorously. 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 consolidated financial statements. The case has been removed to federal district court for the Eastern District of Louisiana. A motion to remand has been filed and the Court officially remanded the case on July 6, 2017. Exceptions for Exploration, YPC and the other defendants have been filed; however, the hearing for such exceptions was continued from the original date of October 6, 2017 to November 22, 2017. As a result of the November 22, 2017 hearing, the case will be de-cumulated into subcases, but the details of this are yet to be determined.

Cameron Parish vs. BEPCO LP, et al & Cameron Parish vs. Alpine Exploration Companies, Inc., et al.

The Parish of Cameron, Louisiana, filed a series of lawsuits against approximately 190 oil and gas companies alleging that the defendants, including Davis, have failed to clear, revegetate, detoxify, and restore the mineral and production sites and other areas affected by their operations and activities within certain coastal zone areas to their original condition as required by Louisiana law, and that such defendants are liable to Cameron Parish for damages under certain Louisiana coastal zone laws for such failures; however, the amount of such damages has not been specified. 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 consolidated financial statements. Two of these lawsuits, originally filed February 4, 2016 in the 38th Judicial District Court for the Parish of Cameron, State of Louisiana, name Davis as defendant, along with more than 30 other oil and gas companies. Both cases have been removed to federal district court for the Western District of Louisiana. The Company denies these claims and intends to vigorously defend them. Davis has become a party to the Joint Defense and Cost Sharing Agreements for these cases. Motions to remand have been filed and the Magistrate Judge has recommended that the cases be remanded. The Company is still waiting for a new District Judge to be assigned to these cases and to rule on the remand recommendation.

Louisiana, et al. Escheat Tax Audits

The States of Louisiana, Texas, Minnesota, North Dakota 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.

Louisiana Severance Tax Audit

The State of Louisiana, Department of Revenue, notified Exploration that it was auditing Exploration's calculation of its severance tax relating to Exploration's production from November 2012 through March 2016. The audit relates to the Department of Revenue's recent interpretation of long-standing oil purchase contracts to include a disallowable "transportation deduction," and thus to assert that the severance tax paid on crude oil sold during the contract term was not properly calculated. The Department of Revenue sent a proposed assessment in which they sought to impose $476,954 in additional state severance tax plus associated penalties and interest. Exploration engaged legal counsel to protest the proposed assessment and request a hearing. Exploration then entered a Joint Defense Group of operators challenging similar audit results. Since the Joint Defense Group is challenging the same legal theory, the Board of Tax Appeals proposed to hear a motion brought by one of the taxpayers that would address the rule for all through a test case. Exploration's case has been stayed pending adjudication of the test case. The hearing for the test case was held on November 7, 2017, and on December 6, 2017, the Board of Tax Appeals rendered judgment in favor of the taxpayer in the first of these cases. The Department of Revenue filed an appeal to this decision on January 5, 2018. 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 consolidated financial statements.

Louisiana Department of Wildlife and Fisheries

The Company received notice from the Louisiana Department of Wildlife and Fisheries ("LDWF") in July 2017 stating that Exploration has open Coastal Use Permits ("CUPs") located within the Louisiana Public Oyster Seed Grounds dating back from as early as November 1993 and through a period ending in November 2012. The majority of the claims relate to permits that were filed from 2000 to 2005. Pursuant to the conditions of each CUP, LDWF is alleging that damages were caused to the oyster seed grounds and that compensation of an aggregate amount of approximately $500,000 is owed by the Company. The Company is currently evaluating the merits of the claim, is reviewing the LDWF analysis, and has now requested that the LDWF revise downward the amount of area their claims of damages pertain to. At this point in the regulatory 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 consolidated financial statements.

Miami Corporation – South Pecan Lake Field Area P&A

The Company, along with several other exploration and production companies in the chain of title, received letters from representatives of Miami Corporation demanding the performance of well plugging and abandonment, facility removal and restoration obligations for wells in the South Pecan Lake Field Area, Cameron Parish, Louisiana. Apache is one of the other companies in the chain of title, and after taking a field tour of the area, has sent to the Company, along with BP and other companies in the chain of title, a proposed work plan to comply with the Miami Corporation demand. The Company is currently evaluating the merits of the claim and the proposed work plan. At this point in the 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 consolidated financial statements.

NOTE 19 – EMPLOYEE BENEFIT PLANS

The Company has a defined contribution 401(k) plan (the "401(k) Plan") for its qualified employees. Employees may contribute any amount of their compensation to the 401(k) Plan, subject to certain Internal Revenue Service annual limits and certain limitations for employees classified as high income. The 401(k) Plan provides for discretionary matching contributions by the Company, and the Company provided a match for employees at a rate of 100 percent of each employee's contribution up to six percent during periods prior to the closing of the Davis Merger, and up to four percent of the employee's base salary after the closing of the Davis Merger. The Company contributed $100,597 and $102,358 under the 401(k) Plan for the years ended December 31, 2017 and 2016, 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 95 percent for the employee portion of the premium, and 80 percent of the dependent portion.

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 $252,649 and $185,503 for the years ended December 31, 2017 and 2016, respectively.

The Company has customary employment agreements with its three executive officers and several employees. Each agreement provides for an annual salary, possible annual incentive awards and benefits such as medical, dental and life insurance as described above.

Each employment agreement is terminable at will by the Company provided that certain lump sum amounts and benefits are payable to the officers and employees upon death or disability or if they are terminated without cause, by the officer and employee for good reason or because of a change in control of the Company. In such events, the Company must pay certain salary termination, accrued bonus and COBRA benefits.

In the unlikely event all executive officers and employees subject to employment agreements were to be terminated at once without cause, total costs and benefits payable by the Company could be approximately $5.3 million, excluding acceleration of outstanding equity awards, accrued bonuses and COBRA benefits. If all executive officers and employees subject to employment agreements were to be terminated under the change of control provisions in the employment agreements, the total costs and benefits payable by the Company could be approximately $8.0 million, excluding acceleration of outstanding equity awards, accrued bonuses and COBRA benefits.

NOTE 20 – 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 the Company'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 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 21 – SALES TO MAJOR CUSTOMERS

In 2017 and 2016, approximately 33% and 39%, respectively, of the Company's natural gas, oil, and natural gas liquids production was transported and processed through pipeline and processing systems owned by EnLink Midstream Partners (formerly CrossTex Energy Partners). The Company takes steps to mitigate these risks through identification of alternative pipeline transportation. The Company expects to continue to transport a substantial portion of its future natural gas production through these pipeline systems.

During the years ended December 31, 2017, and 2016, sales to five customers accounted for approximately 79% and sales to five customers accounted for approximately 78%, respectively, of the Company's total revenues. Management believes that the loss of these customers would not have a material adverse effect on its results of operations or its financial position since the market for the Company's production is highly liquid with other willing buyers.

NOTE 22 – SUBSEQUENT EVENTS

In 2017, the Company entered the Permian Basin through a joint venture with two privately held energy companies and established an AMI covering approximately 33,280 acres in Yoakum County, Texas, located in the Northwest Shelf of the Permian Basin. In January 2018, the Company sold a 12.5% working interest in the project on a promoted basis, and as of March 1, 2018, the Company held a 62.5% working interest in approximately 4,558 gross acres (2,849 net acres).

NOTE 23 – SUPPLEMENTARY INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

The following supplementary information concerning the Company's oil and natural gas exploration, development and production activities reflects only those of the Company in the year ended December 31, 2017. Information at and for the year ended December 31, 2016 combines Davis' reserve and other information with that of Yuma California resulting from the Davis Merger.

Reserves

Proved oil and natural gas reserves are those quantities of oil and natural gas, 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 oil or natural gas 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.

Developed oil and natural gas 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 oil and natural gas 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 as some wells are shut in or uneconomic and do not conform to SEC classifications.

Third Party Procedures and Methods Review

At December 31, 2017 and 2016, NSAI 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. In preparation of the reserve report, NSAI's review consisted of 30 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, 2017 and 2016. The President and Chief Operating Officer, and the reservoir engineering staff presented NSAI 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 natural gas producing activities, and based on crude oil and natural gas reserve and production volumes estimated by NSAI. 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 the Company for fiscal years 2017 and 2016.

Oil and Natural Gas Exploration and Production Activities

Oil and natural gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest, and other contractual provisions. Lease operating expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies, and fuel consumed. Production taxes include production and severance taxes. Depletion of oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts.

Costs Incurred and Capitalized Costs

The costs incurred in oil and natural gas acquisition, exploration, and development activities are as follows:

	Years Ended December 31, 2017	Years Ended December 31, 2016
Costs incurred for the year:		
Exploration (including geological and geophysical costs)	$ 5,216,304	$ 23,000
Development	2,883,801	8,268,653
Acquisition of properties (1)	-	55,479,000
Capitalized overhead	1,606,910	3,688,642
Lease acquisition costs, net of recoveries	2,462,233	670,514
Total costs incurred	$ 12,169,248	$ 68,129,809

(1) Acquisition costs incurred during 2016 consisted entirely of assets acquired in the Davis Merger described in Note 4 – Acquisitions and Divestments.

During the years ended December 31, 2017 and 2016, total costs incurred included estimated cost of future abandonment of $0.3 million and $6.5 million, respectively.

Capitalized costs for oil and natural gas properties are as follows:

	December 31, 2017	December 31, 2016
Oil and natural gas properties		
Capitalized		
Unproved properties	$ 6,794,372	$ 3,656,989
Proved properties	494,216,531	488,723,905
Total oil and gas properties	501,010,903	492,380,894
Less accumulated DD&A	(421,165,400)	(410,440,433)
Net oil and natural gas properties capitalized	$ 79,845,503	$ 81,940,461

Oil and Natural Gas Reserves and Related Financial Data

The following tables present the Company's independent petroleum engineers' estimates of proved oil and natural gas reserves, all of which are located in the United States of America. The Company emphasizes that reserves are estimates that are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

	Oil (Bbls)	NGL (Bbls)	Gas (Mcf)	Boe
Proved reserves at December 31, 2015	1,167,700	1,028,200	15,517,900	4,782,200
Revisions of previous estimates	(3,913,400)	(1,253,000)	(12,481,500)	(7,246,700)
Extension, discoveries and other additions	286,900	-	30,400	292,000
Purchases of minerals in place	5,682,100	1,685,700	23,322,800	11,255,000
Sales of minerals in place	(75,400)	(7,900)	(84,300)	(97,400)
Production	(172,000)	(104,700)	(2,326,400)	(664,400)
Proved reserves at December 31, 2016	2,975,900	1,348,300	23,978,900	8,320,700
Revisions of previous estimates	44,100	(57,800)	112,100	5,000
Extension, discoveries and other additions	235,900	157,200	2,677,700	839,400
Purchases of minerals in place	-	-	-	-
Sales of minerals in place	(643,500)	(22,300)	(87,600)	(680,400)
Production	(250,300)	(131,200)	(3,085,600)	(895,800)
Proved reserves at December 31, 2017	2,362,100	1,294,200	23,595,500	7,588,900
Proved developed reserves				
December 31, 2015	703,300	604,300	10,464,300	3,051,600
December 31, 2016	2,203,000	1,061,000	21,918,700	6,917,100
December 31, 2017	1,763,200	1,009,200	21,130,900	6,294,300
Proved undeveloped reserves				
December 31, 2015	464,400	423,900	5,053,600	1,730,600
December 31, 2016	772,900	287,300	2,060,200	1,403,600
December 31, 2017	598,900	284,900	2,464,600	1,294,600

In 2017, upward revisions of previous estimates are primarily due to price increases extending the economic life of assets. These revisions were partially offset by changes in timing of production. Additions include the reactivation of the SL 18090 #2 well in the Lac Blanc Field and extensions of existing discoveries in Kern County, California. Sales of minerals in place include divesting the Company’s interest in the El Halcón Field during the second quarter of 2017and the sale of proved undeveloped reserves in Santa Barbara County, California.

In 2016, downward revisions of previous estimates are primarily due to removing undeveloped reserves in the Masters Creek Field. The Company elected not to extend its Masters Creek acreage associated with these reserves due to the depressed price environment and the Company’s inability to attract a joint venture partner.

The twelve-month unweighted arithmetic average of the first-day-of-the-month reference prices used in the Company’s reserve estimates at December 31, 2017 and 2016 were $2.98/MMbtu and $51.34/Bbl (WTI) and $2.48/MMbtu and $42.75/Bbl (WTI) for natural gas and oil, respectively.

Standardized Measure of Discounted Future Net Cash Flows

The following table presents a standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves. Future cash flows were computed by applying SEC prices of oil and natural gas, which are adjusted for applicable transportation and quality differentials, to the estimated year-end quantities of those reserves. Future production and development costs were computed by estimating those expenditures expected to occur in developing and producing the proved oil and natural gas reserves at the end of the year, based on year-end costs. Actual future cash flows may vary considerably, and the standardized measure does not necessarily represent the fair value of the Company’s oil and natural gas reserves.

	Year Ended December 31, 2017	Year Ended December 31, 2016
Future cash inflows	$ 222,266,300	$ 200,115,200
Future oil and natural gas operating expenses	(78,791,900)	(67,735,300)
Future development costs	(28,980,100)	(32,071,500)
Future income tax expenses	-	-
Future net cash flows	114,494,300	100,308,400
10% annual discount for estimated timing of cash flows	(41,591,600)	(26,708,300)
Standardized measure of discounted future net cash flows	$ 72,902,700	$ 73,600,100

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the two year period ended December 31, 2017:

	Year Ended December 31, 2017	Year Ended December 31, 2016
January 1	$ 73,600,100	$ 40,980,100
Changes due to current year operation:		
Sales of oil and natural gas, net of oil and natural gas operating expenses	(14,406,288)	(5,433,825)
Extensions and discoveries	11,776,109	2,739,700
Purchases of oil and natural gas properties	-	45,762,176
Development costs incurred during the period that reduced future development costs	3,364,636	7,077,036
Changes due to revisions in standardized variables:		
Prices and operating expenses	18,601,781	(12,181,580)
Income taxes	-	-
Estimated future development costs	(2,252,078)	1,915,239
Quantity estimates	(1,199,960)	(7,876,109)
Sale of reserves in place	(5,945,688)	(2,243,256)
Accretion of discount	7,360,010	4,098,010
Production rates, timing and other	(17,995,922)	(1,237,391)
Net change	(697,400)	32,620,000
December 31	$ 72,902,700	$ 73,600,100

EXHIBIT 21.1

List of Subsidiaries

The Yuma Companies, Inc.
Yuma Exploration and Production Company, Inc.
Texas Southeastern Gas Marketing Company
Yuma Petroleum Company
Pyramid Oil LLC
Davis Petroleum Acquisition Corp.
Davis Petroleum Pipeline LLC
Davis GOM Holdings, LLC
Davis Petroleum Corp.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements on Form S-1 File No. 333-218567, File No. 333-220449, File No. 333-220702, Form S-3 File No. 333-222566 and Form S-8 File No. 333-215605 of our report dated April 2, 2018, relating to the consolidated financial statements of Yuma Energy, Inc. appearing in this Annual Report (Form 10-K) for the year ended December 31, 2017.

/s/ MOSS ADAMS LLP

Houston, Texas
April 2, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated April 12, 2017, with respect to the consolidated financial statements included in the Annual Report of Yuma Energy, Inc. on Form 10-K for the year ended December 31, 2017. We consent to the incorporation by reference of said report in the Registration Statement of Yuma Energy, Inc. on Form S-1 (File No. 333-218567, File No. 333-220449, File No. 333-220702), Form S-3 (File No. 333-222566) and Form S-8 (File No. 333-215605).

/s/ GRANT THORNTON LLP

Houston, Texas
April 2, 2018

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves report dated February 8, 2018, included in the Annual Report on Form 10-K of Yuma Energy, Inc. (the "Company") for the fiscal year ended December 31, 2017, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves report dated February 8, 2018, into the Registration Statements on Form S-1 (File No. 333-218567, File No. 333-220449, File No. 333-220702), Form S-3 (File No. 333-222566) and Form S-8 (File No. 333-215605), filed with the U.S. Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C. H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

Dallas, Texas
April 2, 2018

Exhibit 31.1

Certification

I, Sam L. Banks, certify that:

1. I have reviewed this Annual Report on Form 10-K of Yuma Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Sam L. Banks
Sam L. Banks
Principal Executive Officer
April 2, 2018

Exhibit 31.2

Certification

I, James J. Jacobs, certify that:

1. I have reviewed this Annual Report on Form 10-K of Yuma Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ James J. Jacobs
James J. Jacobs
Principal Financial Officer
April 2, 2018

Exhibit 32.1

Section 1350 Certification

I, Sam L. Banks, certify that:

In connection with the Annual Report on Form 10-K of Yuma Energy, Inc. (the “Company”) for the fiscal year ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Sam L. Banks, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Sam L. Banks
Sam L. Banks
Chief Executive Officer
April 2, 2018

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Section 1350 Certification

I, James J. Jacobs, certify that:

In connection with the Annual Report on Form 10-K of Yuma Energy, Inc. (the "Company") for the fiscal year ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James J. Jacobs, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ James J. Jacobs
James J. Jacobs
Chief Financial Officer
April 2, 2018

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 8, 2018

Mr. Sam L. Banks
Yuma Energy, Inc.
1177 West Loop South, Suite 1825
Houston, Texas 77027

Dear Mr. Banks:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Yuma Energy, Inc. (Yuma) interest in certain oil and gas properties located in California, Louisiana, North Dakota, Oklahoma, and Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Yuma. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Yuma's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Yuma interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	1,101.3	559.6	11,817.1	50,940.9	42,143.1
Proved Developed Non-Producing	661.9	449.6	9,313.8	46,821.1	21,884.6
Proved Undeveloped	598.9	284.9	2,464.6	16,732.3	8,875.0
Total Proved	2,362.1	1,294.2	23,595.5	114,494.3	72,902.7

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Yuma's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Yuma's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of $51.34 per barrel is adjusted by lease for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 per MMBTU is adjusted by lease for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $50.77 per barrel of oil, $24.87 per barrel of NGL, and $2.973 per MCF of gas.

Operating costs used in this report are based on operating expense records of Yuma. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Yuma are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Yuma and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Yuma's estimates of the costs to abandon the existing wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Yuma interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Yuma receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Yuma, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Yuma, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. G. Lance Binder, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1983 and has over 5 years of prior industry experience. Philip R. Hodgson, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ G. Lance Binder
By:
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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

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(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:
  (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
  (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
  (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
    (1) Lifting the oil and gas to the surface; and
    (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
  (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

  (A) Transporting, refining, or marketing oil and gas;
  (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
  (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
  (D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

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(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

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(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence

exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* 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.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.