SECURITIES & EXCHANGE COMMISSION EDGAR FILING

EARTHSTONE ENERGY INC

Form: 10-K

Date Filed: 2017-03-15

Corporate Issuer CIK: 10254

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

FORM 10-K

(Mark One)

☑ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2016

Or

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

Commission File No. 001-35049

EARTHSTONE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**84-0592823**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1400 Woodloch Forest Drive, Suite 300
The Woodlands, Texas 77380
(Address of principal executive offices)
Registrant's telephone number, including area code: (281) 298-4246

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 MKT

Securities registered under 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 15(d) of the Exchange Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to post such filed). 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, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price of $10.78 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 $133,417,225.

As of March 9, 2017 22,273,820 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

TABLE OF CONTENTS

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements contained in this report 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 the “Risk Factors” section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

- volatility and weakness in commodity prices for oil, natural gas and natural gas liquids and the effect of prices set or influenced by action of the Organization of Petroleum Exporting Countries (“OPEC”);
- substantial changes in estimates of our proved reserves;
- substantial declines in the estimated values of our oil and natural gas reserves;
- our ability to replace our oil and natural gas reserves;
- the potential for production decline rates for our wells to be greater than we expect;
- the timing and extent of our success in discovering, acquiring, developing and producing oil and natural gas reserves;
- the ability and willingness of our partners under our joint operating agreements to join in our future exploration, development and production activities;
- our ability to acquire leases and quality services and supplies on a timely basis and at reasonable prices;
- the cost and availability of high quality goods and services with fully trained and adequate personnel, such as drilling rigs and completion equipment;
- risks in connection with potential acquisitions and the integration of significant acquisitions;
- 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;
- the possibility that anticipated divestitures may not occur or could be burdened with unforeseen costs;
- reductions in the borrowing base under our credit facility;
- risks incidental to the drilling and operation of oil and natural gas wells including mechanical failures;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production to market and the impact of these facilities on prices;
- significant competition for oil and natural gas acreage and acquisitions;
- the effect of existing and future laws, governmental regulations and the political and economic climates of the United States;
- our ability to retain key members of senior management and key technical and financial employees;
- changes in environmental laws and the regulation and enforcement related to those laws;
- the identification of and severity of environmental events and governmental responses to these or other environmental events;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulations, derivatives reform, and changes in federal and state income taxes;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we conduct business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets and debt will be disrupted or unavailable;

- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as Africa, the Middle East, and acts of terrorism or sabotage;
- the insurance coverage maintained by us may not adequately cover all losses that may be sustained in connection with our business activities;
- 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;
- title to the properties in which we have an interest may be impaired by title defects; and
- our dependency on the skill, ability and decisions of third party operators of oil and natural gas properties in which we have non-operated working interests.

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

For further information regarding these and other factors, risks and uncertainties affecting us, see Part I, Item 1A. Risk Factors of this report.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and within this report.

3-D seismic – 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.

Bbl - One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

BOE – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

Btu – British thermal unit, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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

Developed acreage – The number of acres which are allotted or assignable to producing wells or wells capable of production.

Development activities – Activities following exploration including the drilling and completion of additional wells and the installation of production facilities.

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

Dry hole or well – A well found to be incapable of producing hydrocarbons economically.

Exploitation – The act of making an oil and natural gas property more profitable, productive or useful.

Exploratory well – A well drilled to find and produce oil or natural gas reserves in an area or a potential reservoir not classified as proved.

Farm-in or ***Farm-out*** – An agreement whereby the owner of a working interest in an oil and natural gas lease assigns or contractually conveys subject to future assignment the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the farmee is required to drill one or more wells in order to earn its interest in the acreage. The farmor usually retains a royalty and/or an after-payout interest in the lease. The interest received by the farmee is a “farm-in” while the interest transferred by the farmor is a “farm-out.”

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

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

HBP – Held by production, a mineral lease provision that extends the right to operate a lease as long as the property produces a minimum quantity of oil and/or natural gas.

Horizontal drilling – A drilling technique that permits the operator to drill horizontally within a specified targeted reservoir and thus exposes a larger portion of the producing horizon to a wellbore than would otherwise be exposed through conventional vertical drilling techniques.

Hydraulic fracture or Frac – A well stimulation method by which fluid (approximately 95-98% water) and proppant (purposely sized particles used to hold open an induced fracture) are injected downhole and into the producing formation at high pressures and rates in order to exceed the rock strength and create a fracture such that the proppant material can be placed into the fracture to enhance the productive capability of the formation.

Injection well – A well which is used to inject gas, water, or liquefied petroleum gas under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

Joint Operating Agreement or ***JOA*** – Any agreement between working interest owners c oncerning the duties and responsibilities of the operator and rights and obligations of the non-operators.

MBbls – One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE – One thousand barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

MMBtu – One million Btu.

Mcf – One thousand cubic feet.

MMcf – One million cubic feet.

Net acres or net wells – The sum of the fractional working interests owned in gross acres or gross wells.

NGLs – Natural gas liquids measured in barrels.

NYMEX – The New York Mercantile Exchange.

Plugging and abandonment or ***P&A*** – Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface.

PV-10 – The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, (ii) non-property related expenses such as general and administrative expenses, debt service and future income tax expense, or (iii) depreciation, depletion and amortization.

Productive well – A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proppant – A solid material, typically treated sand or man-made ceramic materials, designed to keep an induced hydraulic fracture open, during or following a fracturing treatment.

Proved developed nonproducing reserves or ***PDNP*** – Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved developed but nonproducing reserves.

Proved developed producing reserves or ***PDP*** – Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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

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

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

Re-engineering – A process involving a comprehensive review of the mechanical conditions associated with wells and equipment in producing fields. Our re-engineering practices typically result in a capital expenditure plan which is implemented over time to workover (see below) and re-complete wells and modify down hole artificial lift equipment and surface equipment and facilities. The programs are designed specifically for individual fields to increase and maintain production, reduce down-time and mechanical failures, lower per-unit operating expenses, and therefore, improve field economics.

Reservoir – A 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.

Royalty interest – An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

Shut-in reserves – Those reserves expected to be recovered from completion intervals that were open at the time the reserve was estimated but were not producing due to market conditions, mechanical difficulties or because production equipment or pipelines were not yet installed. These reserves are included in the PDNP category in our reserve report.

Slickwater – A method of hydraulic fracturing that uses water with a minor amount of chemicals in order to stimulate rock and enhance fluid flow.

Swing producer – A supplier or a close oligopolistic group of suppliers of any commodity, controlling its global deposits and possessing large spare production capacity.

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

Working interest or **WI** – The ownership interest, generally defined in a JOA, that gives the owner the right to drill, produce and/or conduct operating activities on the property and share in the sale of production, subject to all royalties, overriding royalties and other burdens and obligates the owner of the interest to share in all costs of exploration, development operations and all risks in connection therewith.

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

PART I

Item 1. Business

Overview

Earthstone Energy, Inc. (together with our consolidated subsidiaries, the “Company,” “our,” “we,” “us,” “Earthstone” or similar terms), a Delaware corporation formed in 1969, is a growth-oriented independent oil and natural gas development and production company. In addition, the Company is active in corporate mergers and the acquisition of oil and natural gas properties that have production and future development opportunities. Our operations are all in the upstream segment of the oil and natural gas industry and all our properties are onshore in the United States.

Our reserve portfolio primarily consists of assets in the Midland Basin of west Texas, the Eagle Ford trend of south Texas and in the Williston Basin of North Dakota. We have approximately 5,900 net leasehold acres in the Midland Basin, representing an average 40% working interest, located in Howard, Glasscock, Martin and Midland Counties. We have approximately 21,000 net leasehold acres in the Eagle Ford trend of south Texas, including approximately 18,000 net leasehold acres in the crude oil window in Fayette, Gonzales and Karnes Counties, with working interests ranging from approximately 25% to 50%, and approximately 3,000 net leasehold acres located in the natural gas and condensate window in La Salle County, with working interests averaging approximately 11%. In the Williston Basin of North Dakota, we have approximately 5,900 net leasehold acres, with working interests ranging from approximately 1% to 6%.

Our corporate headquarters are located in The Woodlands, Texas. We also have an operating office in Denver, Colorado and two field offices in south Texas. Our common stock, $0.001 par value per share (the “Common Stock”) is traded on the NYSE MKT under the symbol ESTE.

Recent Developments

Acquisitions

On November 7, 2016, we entered into a contribution agreement (the “Bold Contribution Agreement”), by and among the Company, Earthstone Energy Holdings, LLC, a newly formed Delaware limited liability company (“EEH”), Lynden USA, Inc., a Utah corporation (“Lynden USA”), an existing subsidiary of Earthstone, Lynden USA Operating, LLC, a newly formed Texas limited liability company (all wholly-owned subsidiaries of the Company), Bold Energy Holdings, LLC, a Texas limited liability company (“Bold Holdings”), and Bold Energy III LLC, a Texas limited liability company (“Bold”).

Under the Bold Contribution Agreement, the terms of which were unanimously approved by a special committee of disinterested members of the Company’s Board of Directors and the full Board (i) the Company will recapitalize the Common Stock into two classes, consisting of Class A and Class B, and all of its existing Common Stock will be converted into Class A common stock. Bold Holdings will purchase approximately 36.1 million shares of the Company’s Class B common stock for nominal consideration, with the Class B common stock having no economic rights in the Company other than voting rights on a pari passu basis with the Class A common stock. In addition, EEH will issue approximately 22.3 million of its membership units to the Company and Lynden USA, in the aggregate, and approximately 36.1 million membership units to Bold Holdings in exchange for each of the Company, Lynden USA and Bold Holdings transferring all of their assets to EEH; and (iii) each Bold Holdings’ membership unit in EEH, together with one share of Bold Holdings Class B common stock, will be convertible into Class A common stock on a one-for-one basis. Therefore, upon the closing of Bold Contribution Agreement, stockholders of the Company and unitholders of Bold Holdings are expected to own approximately 39% and 61%, respectively of the combined company’s then outstanding Class A and Class B common stock on a fully diluted basis. After closing, the Company expects conduct its activities through EEH and will be its sole managing member. The Bold Contribution Agreement is expected to close in the second quarter of 2017 and is subject to approval of the Company’s stockholders and other customary closing conditions.

In May 2016, we acquired Lynden Energy Corp. (“Lynden”) in an all-stock transaction. The acquisition was made through an arrangement (the “Lynden Arrangement”) instead of a merger because Lynden is incorporated in British Columbia, Canada. The Company acquired all the outstanding shares of common stock of Lynden through a newly formed Company subsidiary, with Lynden surviving in the Lynden Arrangement as a wholly-owned subsidiary of the Company. The Company issued 3,700,279 shares of its common stock to the holders of Lynden common stock in the Lynden Arrangement.

Non-Recent Acquisitions

In December 2014, we acquired three operating subsidiaries of Oak Valley Resources, LLC, a privately-held Delaware limited liability company (“OVR”), in exchange for shares of our Common Stock (the “Exchange”), which resulted in a change of control. Pursuant to the Exchange Agreement, OVR contributed to us the membership interests of its three subsidiaries, Earthstone Operating, LLC (formerly Oak Valley Operating, LLC) (“OVO”), EF Non-Op, LLC (“EF Non-Op”) and Sabine River Energy, LLC (“Sabine”), each a Texas limited liability company (collectively “Oak Valley”), in exchange for approximately 9.124 million shares, representing 84% of our Common Stock. The Exchange was accounted for as a reverse acquisition whereby Oak Valley was considered the acquirer for accounting purposes. All historical financial information contained in this report is that of Oak Valley. Upon the closing of the Exchange, we changed our fiscal year from March 31 to December 31 in order for our fiscal year end to correspond with the fiscal year end of OVR and its subsidiaries.

Immediately following the Exchange, we acquired an additional 20% undivided ownership interest in certain crude oil and natural gas properties located in Fayette and Gonzales Counties, Texas, in exchange for the issuance of approximately 2.957 million shares of our Common Stock (the “Flatonia Contribution Agreement”) to Flatonia Energy, LLC (“Flatonia”), increasing our ownership in these properties from a 30% undivided ownership to a 50% undivided ownership interest. As a result of the share issuance to Flatonia, OVR’s ownership in us decreased from 84% to 66%.

For further discussion of the above closed acquisitions, see *Note 3. Acquisitions and Divestitures* within the *Notes to Consolidated Financial Statements* included in Item 8 of this report.

Our Business Strategy

We pursue a value-driven growth strategy focused on projects that we believe will generate strong and predictable rates of return and increases in stockholder value. Although we currently have significant non-operated properties, our intent is to operate the majority of our properties in order to control costs and direct the efficient development of such properties in an effort to optimize investment returns and profitability. Historically, we have operated the majority of our assets and implemented our strategy in multiple basins in order to enable us to benefit from regional changes and differences in realized prices, service costs, service availability and numerous other factors that would enhance the timely, cost-efficient and economic development of our assets, and lead to greater rates of return. This multi-basin strategy could change in the future and we could focus all or a majority of our capital expenditures in a single basin, as a result of acquisitions, project economics and capital market considerations. Management concentrates on building production, reserves and cash flows while seeking to expand our undeveloped acreage and drilling inventory. Further expansion of our asset base will be achieved through cost efficient development, exploitation and operation of our current assets and acreage and through additional leasing, acquisitions, development, drilling and, to a lesser extent, exploration activities, currently directed toward unconventional oil-weighted projects. Finally, management intends to pursue corporate and asset acquisition opportunities.

Our business strategy includes the following:

- pursuing value-accretive corporate merger and acquisition opportunities;
- expanding our operated acreage positions and drilling inventory in our areas of primary interest through acquisitions and farm-in opportunities;
- continuing the cost-effective development and exploitation of our existing acreage positions;
- generating additional development projects in our areas of primary interest;
- divesting non-core assets in order to streamline operations and utilize capital and human resources most effectively;
- maintaining a strong balance sheet and capital structure; and
- obtaining additional capital, as needed and available, through the issuance of equity and debt securities or by soliciting industry or financial participants to jointly develop and/or acquire assets

Our fundamental operating and technical strategy is complemented by our focus on increasing stockholder value by our efforts in:

- maximizing profit margins;
- controlling capital expenditures and operating and administrative costs; and
- promoting industry or institutional participants into projects to manage risk, enhance rates of return and lower net finding and development costs.

Management believes its strategy is appropriate because it addresses multiple risks of oil and natural gas operations while providing equity holders with upside potential and results in “staying power,” which management believes is essential to mitigate the adverse impacts of historically volatile commodity prices and financial markets.

Our Operations

We are currently the operator of properties containing approximately 38% of our proved oil and natural gas reserves and 58% of our proved PV-10 as of December 31, 2016 (see reconciliation of PV-10 to the standardized measure of discounted future net cash flows in Item 2. Properties). As operator, we are able to directly influence development and production of operations of our operated properties. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price fluctuations. Our status as an operator has allowed us to pursue the development of undeveloped acreage, further develop existing properties and generate new projects that we believe have the potential to increase stockholder value.

As is common in our industry, we participate in non-operated properties on a selective basis. Decisions to participate in non-operated properties are dependent upon the technical and economic nature of the projects and the operating expertise and financial standing of the operators.

Description of Major Properties

The following is a brief description of our primary oil and natural gas properties:

Midland Basin

We have a non-operated position of approximately 5,900 net acres in the Midland Basin of west Texas. At present, our most active area within the basin is the horizontal Wolfcamp play occurring in Howard, Glasscock, Martin and Midland Counties, Texas. We have approximately 112 gross vertical and 5 gross horizontal producing wells with an average working interest of approximately 40% that are primarily operated by Crownquest Operating, LLC. We have identified approximately 180 gross horizontal locations in various benches of the Wolfcamp and Lower Spraberry as well as approximately 118 gross vertical wells that have potential in the Clearfork, Spraberry, Wolfcamp, Strawn and Fusselman formations.

Upon the closing of the Bold Contribution Agreement, we expect to have an operated position in approximately 20,900 net acres in the core of the Midland Basin across Reagan, Upton, Midland, Glasscock, Howard and Martin counties. The acreage is approximately 99% operated with an average working interest of approximately 85%. Current internal estimates indicate approximately 500 gross, largely de-risked operated drilling locations, the vast majority of which are in certain benches of the Wolfcamp A and B formation in the Lower Spraberry formation. Based on industry drilling and production operations additional locations may be proven to be economic, primarily in Reagan and Upton counties, in added benches in the Wolfcamp A, B and C and other formations.

Eagle Ford Basin

Operated Eagle Ford

As of December 31, 2016, we owned approximately 36,000 gross (17,600 net) leasehold acres in Fayette, Gonzales and Karnes Counties, Texas. The acreage is located in the crude oil window of the Eagle Ford shale trend of south Texas and is prospective for the Eagle Ford, Austin Chalk, Upper Eagle Ford, Buda, Wilcox and Edwards formations. We serve as the operator with a range of approximately 25% to 50% undivided ownership interest in substantially all of the acreage.

As of December 31, 2016, we operated 70 gross Eagle Ford wells and 9 gross Austin Chalk wells and had non-operated interests in two gross producing Eagle Ford wells and one gross producing Austin Chalk well. We have identified a total of approximately 140 gross Eagle Ford drilling locations in this acreage. The number of Eagle Ford locations could potentially increase subject to future down spacing initiatives and successful implementation of slickwater enhanced completions. In addition, because our acreage position is prospective for the Austin Chalk, Upper Eagle Ford, Buda, Wilcox and Edwards formations, we may have additional future economic locations. The majority of our acreage is covered by an approximately 173 square mile 3-D seismic survey, which is being used to develop the Eagle Ford and identify Austin Chalk locations and other economic opportunities.

Non-Operated Eagle Ford

We have a non-operated position in approximately 25,500 gross (2,900 net) acres in two areas within the Hawkville Field in La Salle County, Texas. The acreage is operated by BHP Billiton and Lewis Petro Properties, Inc. and is prone to natural gas and condensate produced from the Eagle Ford formation. The two areas are summarized below:

a) White Kitchen – We have an average working interest of approximately 12% in approximately 7,100 gross acres, all of which is held by production. As of December 31, 2016, 30 gross wells were producing, and we have identified approximately 40 additional drilling locations.

b) Martin Ranch – We have a 10% working interest in approximately 18,000 gross acres. As of December 31, 2016, 31 gross wells were producing, and we have identified approximately 140 potential drilling locations in the acreage.

Williston Basin

We have a non-operated position in approximately 9, 300 net acres in the Williston Basin of North Dakota. At present, our most active area within the basin is the Banks Field in McKenzie County, North Dakota. In the Banks Field, we have an average working interest of approximately 3.9% in 99 gross horizontal Bakken/Three Forks producing wells that are primarily non-operated. We have an additional 13 gross wells waiting on completion in the Banks Field with an average working interest of approximately 5%. We have identified approximately 210 gross potential drilling locations which are in existing producing units throughout the Bakken/Three Forks play.

Competition

The domestic oil and natural gas industry is intensely competitive in the exploration for and acquisition of reserves and in the producing and marketing of its 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 may be able to pay more for seismic information and lease rights on oil and natural gas properties and to define, evaluate, bid for and purchase a greater number of properties, than our financial or human resources permit. Our ability to acquire additional properties in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate related transactions in a highly competitive environment.

Seasonality of Business

Weather conditions often 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 exploitation, development and production involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover, 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, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, participation agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; as well as pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

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

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration, development and production activities related to oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration and/or development while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, 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.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically govern the permitting, construction and operation of a well of 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 address various aspects of our business including oil and natural gas exploration, development 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 business, financial condition or results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

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

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration, development and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and natural gas wastes and reclassify them as hazardous wastes or subject them to enhanced solid waste regulation. If such proposals were to be enacted, they could have a significant impact on our operating costs and on those of all the industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration, development and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

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

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

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. In particular, the well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and 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.

Under the direction of Congress, the EPA completed a study finding that hydrauli c fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. The EPA has also finalized pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations to municipal sewage treatment plants. Beyond that, several environmental groups have petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning and Community Right-to-Know Act to the oil and natural gas extraction industry and to require disclosure under the Toxic Substances Control Act of chemicals used in fracturing. Congress might likewise consider legislation to amend the federal SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Certain states, including Colorado, Utah and Wyoming, already have issued similar disclosure rules.

In addition, the Department of the Interior has promulgated regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes lands on which we conduct or plan to conduct operations. States similarly have been imposing new restrictions or bans on hydraulic fracturing. Even local jurisdictions have adopted, or tried to adopt, regulations restricting hydraulic fracturing. Additional hydraulic fracturing requirements at the federal, state or local level may limit our ability to operate or increase our operating costs.

Air Emissions

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

In 2012 and 2016, the EPA issued air regulations for the oil and natural gas industry that address emissions from certain new sources of volatile organic compounds (“VOCs”), sulfur dioxide, air toxics and methane. The rules include the first federal air standards for oil and natural gas wells that are hydraulically fractured, or refractured, as well as requirements for other processes and equipment, including storage tanks. Compliance with these regulations has imposed additional requirements and costs on our operations. The EPA also has started to consider whether to extend such regulations to existing wells.

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. Implementation will take place over several years; however, the new standard could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response to these studies, governments have 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 several countries including those comprising the European Union, have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

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

In addition, the Obama Administration developed a Strategy to Reduce Methane Emissions that was intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels. Consistent with that strategy, the EPA issued its air rules for oil and natural gas production sources, and the federal Bureau of Land Management (“BLM”) promulgated standards for reducing venting and flaring on public lands.

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

The National Environmental Policy Act

Oil and natural gas exploration, development and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. This process has the potential to delay the development of future oil and natural gas projects.

Threatened and endangered species, migratory birds and natural resources

Various 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, the Migratory Bird Treaty Act and the Clean Water Act. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. 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 govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act and may require that information be provided to state and local government authorities, as well as the public.

Occupational Safety and Health Act

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

Employees

As of December 31, 2016, we had 48 full-time employees and one part-time employee; 9 are management, 13 are technical personnel, 15 are administrative personnel and 12 are field operations employees. Our employees are not covered under a collective bargaining agreement nor are any employees represented by a union. We consider all relations with our employees to be satisfactory.

Office Leases

We lease office space as set forth in the following table:

Location	Approximate Size	Lease Expiration Date	Intended Use
The Woodlands, Texas	19,600 sq. ft.	December 31, 2019	Office
Denver, Colorado	7,000 sq. ft.	April 30, 2018	Office

During 2016, aggregate rental payments for our office facilities totaled approximately $0.8 million.

Available Information

Our principal executive offices are located at 1400 Woodloch Forest Drive, Suite 300, The Woodlands, Texas 77380. Our telephone number is (281) 298-4246. You can find more information about us at our website located at www.earthstoneenergy.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 Securities and Exchange Commission ("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 (1-800-732-0330). 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

Our business is subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our shares, you should carefully consider the risk factors included below as well as those matters referenced in this report under “Cautionary Statement Concerning Forward-Looking Statements” and other information included and incorporated by reference into this report.

Oil, natural gas and natural gas liquids prices have been historically volatile. Their prices since 2014 have adversely affected, and may continue to adversely affect, our business, financial condition and results of operations and may in the future affect our ability to meet our financial commitments as well as negatively impact our stock price.

The prices we receive for our oil, natural gas and natural gas liquids production heavily influence our revenues, profitability, access to capital and future rate of growth. These hydrocarbons are commodities, and therefore, their prices may be subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, natural gas and natural gas liquids has been volatile. For example, during the period from January 1, 2014 through December 31, 2016, 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 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. Likewise, natural gas liquids, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics, have suffered significant declines in realized prices since the fall of 2014. The prices we receive for oil, natural gas and natural gas liquids we produce and our production levels depend on numerous factors beyond our control, including:

- worldwide and regional economic and financial conditions impacting global and regional supply and demand;
- the level of global exploration, development and production;
- the level of global supplies, in particular due to supply growth from the United States;
- foreign and domestic supply capabilities;
- the price and quantity of U.S. imports and exports, including liquefied natural gas;
- political conditions in or affecting other oil, natural gas and natural gas liquids producing countries, including the current conflicts in the Middle East, as well as conditions in South America, Africa, Ukraine and Russia;
- actions of the OPEC and state-controlled oil companies relating to production and price controls;
- the extent to which U.S. shale producers become Swing Producers adding or subtracting to the world supply totals;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- current and future regulations regarding well spacing;
- prevailing prices on local oil, natural gas and natural gas liquids price indices in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, natural gas and natural gas liquids prices have and may continue to reduce our cash flows and borrowing capacity. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our hydrocarbon reserves as existing reserves are depleted. A decrease in prices could render development projects and producing properties uneconomic potentially resulting in a loss of mineral leases.   Low commodity prices have, at times, caused significant downward adjustments to our estimated proved reserves, and may cause us to make further downward adjustments in the future. Furthermore, our borrowing capacity could be significantly affected by decreased prices. Under our agreement providing for a senior secured revolving credit facility (the “Credit Agreement”), our borrowing base is subject to semi-annual redeterminations (May 1 and November 1) and the lenders have the right to call for an interim determination of the borrowing base under certain specified circumstances. A sustained decline in oil, natural gas and natural gas liquids prices could adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligations under the Credit Agreement to the extent our outstanding borrowings exceed the redetermined borrowing base and cold otherwise materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower oil, natural gas and natural gas liquids gas prices may cause a further decline in the price of our shares.

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

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on 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 further, write-down the carrying value of our oil and natural gas properties, which constitutes a non-cash charge to earnings.

Oil, natural gas and natural gas liquids prices have been significantly lower than they were in mid-2014. If those 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 6. Oil and Natural Gas Properties* to our consolidated financial statements included in this report for additional information.

Any significant reduction in our borrowing base under our Credit Agreement as a result of a periodic borrowing base redetermination or otherwise may negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our Credit Agreement or any other obligation if required as a result of a borrowing base redetermination.

Availability under our Credit Agreement is currently subject to a borrowing base of $80.0 million. The borrowing base is subject to scheduled semiannual redeterminations (May 1 and November 1), as well as other elective borrowing base redeterminations. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Agreement. Reductions in estimates of our oil, natural gas and natural gas liquids reserves may result in a reduction in our borrowing base under our Credit Agreement (if prices are kept constant). Reductions in our borrowing base under our Credit Agreement could also arise from other 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 liquids reserve engineering techniques;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

As of March 1, 2017, we had $10.0 million of borrowings outstanding under our Credit Agreement. We may make further borrowings under our Credit Agreement in the future. Any significant reduction in our borrowing base under our Credit Agreement as a result of borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, could have a material adverse effect on our financial position, results of operation and cash flows. Further, if the outstanding borrowings under our Credit Agreement were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess.

Unless we replace our reserves, our production and estimated reserves will decline, which may adversely affect our financial condition, results of operations and/or 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. 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 properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of 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 it requires significant decisions 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 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 property 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 a non-cash charge to earnings. See *Note 6. Oil and Natural Gas Properties*, to our consolidated financial statements included in this report.

At December 31, 2016, approximately 22% of our estimated reserves were classified as proved undeveloped. Recovery of estimated proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The estimated reserve data assumes that we will make specified capital expenditures to develop our reserves. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations; however, actual capital expenditures may 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 is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2016, 2015 and 2014, 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:

- the actual prices we receive for oil and natural gas;
- the 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 us 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.

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

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of respective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. 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 exploratory drilling is unsuccessful.

The capitalized costs of our oil and natural gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, we would record impairment charges to reduce the capitalized costs of such field to our estimate of the field's fair market value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce our earnings and stockholders' equity and could adversely affect our stock price.

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.

Future drilling and completion activities associated with identified drilling locations may be adversely affected by factors that could materially alter the occurrence or timing of their drilling and completion, which in certain instances could prevent production prior to the expiration date of mineral leases for such locations.

Although our management team has identified numerous potential drilling locations as a part of our long-range planning related to future drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of factors, which are beyond our control , including, the availability and cost of capital, oil, natural gas and natural gas liquids prices, drilling and production costs, the availability of drilling services and equipment, drilling results (including the impact of increased horizontal drilling density and longer laterals), lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. As such, our actual drilling and completion activities, may materially differ from those presently anticipated. Accordingly, it is not certain that these potential drilling locations will be developed or if we will be able to produce significant oil, natural gas and natural gas liquids from these or any other potential drilling locations. Unless production is established, in accordance with the terms of mineral leases that are associated with these locations, such leases could expire.

We have incremental cash inflows and outflows as a result of our hedging activities. To the extent we are unable to obtain future hedges at attractive prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

In an effort to achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we often enter into derivative instrument contracts for a portion of our oil and natural gas production, including swaps, collars, puts and basis swaps. We recognize all derivatives as either assets or liabilities, measured at fair value, and recognizes changes in the fair value of derivatives in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments. As our derivative instrument contracts expire, there is uncertainty that we will be able to comparably replace them.

Derivative instruments can expose us to the risk of financial loss in varying circumstances, including, but not limited to, when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price stated in the derivative instrument contract and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

For additional information regarding our hedging activities, please see Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

The oil and natural gas industry is highly competitive, and our small size puts us at a disadvantage in competing for resources.

The oil and natural gas industry is highly competitive. We compete with major integrated and larger independent oil and natural gas companies in seeking to acquire desirable oil and natural gas properties and leases, for the equipment and services required to develop and operate properties, and in the marketing of oil and natural gas to end-users. Many of our competitors have financial and other resources that are substantially greater than ours, which makes acquisitions of acreage or producing properties at economic prices difficult. Significant competition also exists in attracting and retaining technical personnel, including geologists, geophysicists, engineers, landmen and other specialists, as well as financial and administrative personnel and we may be at a competitive disadvantage to companies with larger financial resources than ours.

A failure to complete additional acquisitions could limit our potential growth.

Our future success is highly dependent on our ability to acquire and develop mineral leases and oil and gas properties with economically recoverable oil and natural gas reserves. Without continued successful acquisition, of economic development projects, our current estimated oil and natural gas reserves will decline due to continued production activities. Acquiring additional oil and natural gas properties, or businesses that own or operate such properties is an important component of our business strategy. If we identify an appropriate acquisition candidate, management may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. Our limited access to financial resources compared to larger, better capitalized companies may limit our ability to make future acquisitions. If we are unable to complete suitable acquisitions, it may be more difficult to replace and increase our reserves, and an inability to replace our reserves may have a material adverse effect on our financial condition and results of operations.

Acquisitions involve a number of risks, including the risk that we will discover unanticipated liabilities or other problems associated with the acquired business or property.

In assessing potential acquisitions, we will 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 problems, title defects 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.

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 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 the acquired properties.

Our previously announced proposed transaction with Bold Energy Holdings, LLC (“Bold”) pursuant to the “Bold Contribution Agreement” is subject to material risks.

On November 7, 2016, we entered into the Bold Contribution Agreement. The purpose of that agreement is to provide for the business combination between Earthstone and Bold. Bold owns significant developed and undeveloped oil and natural gas properties in the Midland Basin of west Texas. Although we expect to complete the Bold Contribution Agreement, its completion is not assured and is subject to risks, including the risks that approval of the Bold Contribution Agreement by our stockholders will not be obtained or that certain other closing conditions will not be satisfied. If during the pendency of the Bold Contribution Agreement or if it is not completed, our ongoing business and financial results may be adversely affected, including:

- us having to pay certain significant transaction costs relating to an unsuccessful Transaction;
- restrictions in our ability to pursue alternatives to the Bold Contribution Agreement, which could discourage a potential acquirer from making an alternative proposal to us;

- the potential payment of a termination fee of $5.5 million in certain instances if we accept a proposal from anothe r party we believe to be superior to the Bold Contribution Agreement or if we breach our non-solicitation or other representations, warranties or covenants;
- the fact that we are subject to certain restrictions in the conduct of our business prior to closing or termination of the Transaction which may prevent us from making certain acquisitions or dispositions or pursuing certain business opportunities;
- the potential decline in the share price of our Common Stock to the extent that the market prices reflect an assumption by the market that the Bold Contribution Agreement will not be completed or if, in fact, it is not completed at all; and
- we may be subject to litigation related to any failure on our part to complete the Bold Contribution Agreement, or litigation resulting from minority stockholder actions.

Completion of the Bold Contribution Agreement may also give rise to additional business risks, including:

- the fact that our sole material asset will be our equity interest in EEH, which will be the holding company for all our assets and Bold's assets and accordingly we will be dependent on distributions from EEH to pay taxes and cover our corporate and other overhead expenses;
- we may experience difficulties in integrating our business with Bold's business, which could cause the combined company to fail to realize many of the anticipated potential benefits of the Bold Contribution Agreement; and
- most of our current stockholders will have a reduced ownership and voting interest after the Bold Contribution Agreement.

These and other considerations and risks associated with the Bold Contribution Agreement will be fully discussed in a proxy statement to be delivered to our stockholders when available.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations, including our drilling operations.

Oil and natural gas exploration, development and production activities are subject to numerous significant operating risks, including the possibility of:

- unanticipated, abnormally pressured formations;
- significant mechanical difficulties, such as stuck drilling and service tools and casing collapses;
- blowouts, fires and explosions;
- personal injuries and death;
- uninsured or underinsured losses; and
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination.

Any of these operating hazards could cause damage to properties, reduced cash flows, serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages, which could expose us to significant liabilities. Although we believe we are adequately insured for replacement costs of our wells and associated equipment, the payment of any of these liabilities could reduce the funds available for exploration, development, and acquisition, or could result in a loss of our properties.

The nature of our business and assets exposes us to significant compliance costs and liabilities.

Our operations involving the exploration, development and production of hydrocarbons are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment as well as protection of the environment, operational safety, and related employee health and safety matters. Laws and regulations applicable to us include those relating but not limited to the following:

- land use restrictions;
- delivery of our oil and natural gas to market;

- drilling bonds and other financial responsibility requirements;
- spacing of wells;
- air emissions;
- property unitization and pooling;
- habitat and endangered species protection, reclamation and remediation;
- containment and disposal of hazardous substances, oil field waste and other waste materials;
- drilling permits;
- use of saltwater injection wells, which affects the disposal of saltwater from our wells;
- safety precautions;
- prevention of oil spills;
- operational reporting; and
- taxation and royalties.

Compliance with these laws and regulations is a significant cost of doing business. Failure to comply with applicable laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory and remedial liabilities; the issuance of injunctions that may restrict, inhibit or prohibit our operations; and claims of damages to property or persons.

Some environmental laws and regulations impose strict liability, which means that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or for the conduct of prior operators of properties we acquired or of other third parties. Similarly, some environmental laws and regulations impose joint and several liability, meaning that we could be held responsible for more than our share of a particular reclamation or other obligation, and potentially the entire obligation, where other parties were involved in the activity giving rise to the liability. In addition, we may be required to make large and unanticipated capital expenditures to comply with applicable laws and regulations, for example by installing and maintaining pollution control devices. Similarly, our actual plugging and abandonment obligations may be more than our estimates. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters, but we estimate that they will be material. Environmental risks are generally not fully insurable.

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 federal Bureau of Land Management (the “BLM”) rulemaking for hydraulic fracturing practices on federal and Indian lands resulted in a 2015 final rule that requires public disclosure of chemicals used in hydraulic fracturing, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states, including North Dakota where we conduct operations, and have interests in numerous non-operated wells and have adopted, and other states are considering or have adopted more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local la nd use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

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 U.S. Environmental Protection Agency (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 federal 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. In addition, the BLM has promulgated standards for reducing venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Obama Administration that were intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

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

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 products.

Our oil, natural gas and natural gas liquids are sold to 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 is sold to a limited number of geographic markets which each have 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. 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 of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

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 hedging 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 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. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and natural gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar 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.

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 liquids and natural gas, 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 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.

Crude oil from the Bakken / Three Forks formations may pose unique hazards that may have an adverse effect on our operations.

The United States Department of Transportation (“USDOT”) has concluded that crude oil from the Bakken / Three Forks formations has a higher volatility than most other crude oil from the United States and thus is more ignitable and flammable. Based on that information, and several fires involving rail transportation of crude oil, USDOT imposed additional requirements for shipping crude oil by rail. Beyond that, the rail industry has adopted increased precautions for crude shipments. Any restrictions that significantly affect transportation of crude oil production could materially and adversely affect our financial condition, results of operations and cash flows.

Any change to government regulation or administrative practices may have a negative impact on our ability to operate and our profitability.

Oil and natural gas operations are subject to substantial regulation under federal, state and local laws relating to the exploration for, and the development, upgrading, marketing, pricing, taxation, and transportation of, oil and natural gas and related products and other associated matters. Amendments to current laws and regulations governing operations and activities of oil and natural gas exploration and development operations could have a material adverse impact on our business. In addition, there can be no assurance that income tax laws, royalty regulations and government incentive programs related to our oil and natural gas properties and the oil and natural gas industry generally will not be changed in a manner which may adversely affect our progress or cause delays.

Permits, leases, licenses, and approvals are required from a variety of regulatory authorities at various stages of exploration and development. There can be no assurance that the various government permits, leases, licenses and approvals sought will be granted in respect of our activities or, if granted, will not be cancelled or will be renewed upon expiration. There is no assurance that such permits, leases, licenses, and approvals will not contain terms and provisions which may adversely affect our exploration and development activities.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not own or control. If these facilities or systems are unavailable, our oil and natural gas production can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production is dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems, transportation and processing facilities owned by third parties. In general, we will not control these facilities, and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the hydrocarbons we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our hydrocarbons is dependent upon coordination among third parties that own transportation and processing facilities we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. These are risks for which we generally will not maintain insurance.

Use of debt financing may adversely affect our strategy.

We may use debt to fund a portion of our future acquisition, development and/or operating activities. Any temporary or sustained inability to service or repay such debt will likely have a material adverse effect on our ability to access financing markets and pursue our operating strategies, as well as impair our ability to respond to adverse economic changes in oil and natural gas markets and the economy in general.

Non-operated properties are controlled by third parties that may not allow us to proceed with our planned capital expenditures. Activities on our operated properties could also be limited or subject to penalties.

We currently are not the operator of many of our existing properties and, therefore, may not be able to influence production operations or further development activities. Joint ownership is customary in the oil and natural gas industry and is generally conducted under the terms of a joint operating agreement ("JOA"), where one of the working interest owners is designated as the "operator" of the property. For non-operated properties, subject to the specific terms and conditions of the applicable JOA, if we disagree with the decision of a majority of working interest owners, we may be required, among other things, to postpone proposed activity or decline to participate in drilling and completing of wells. If we decline to participate, we might be forced to relinquish our interest through "in-or-out" elections or may be subject to certain non-consent penalties, as provided in a JOA. In-or-out elections may require a joint owner to participate or forever relinquish its position, typically only in specific wells or drilling units, although such relinquished positions could be of a larger scope. Non-consent penalties typically allow participating working interest owners to recover from the proceeds of production, if any, an amount equal to 200% to 500% of the non-participating working interest owner's share of the cost of such operations. Further, even for properties operated by us, there may be instances where decisions related to drilling, completion and operating cannot be made in our sole discretion. In such instances, we could be limited in our development operations and subject to penalties as specified above if we choose not to participate in operations proposed by a majority of working interest owners.

Because we cannot control activities on properties we do not operate, we cannot directly control the timing of exploration and development projects. If we are unable to fund required capital expenditures with respect to non-operated properties, our interests in those properties may be reduced or forfeited.

Our ability to exercise influence over operations and costs for the properties we do not operate is limited. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to exploration, exploitation, development or acquisition activities. The success and timing of exploration, exploitation and development activities on properties operated by others depend upon a number of factors that may be outside our control, including but not limited to:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of technology.

Where we are not the majority owner or operator of a particular oil and natural gas project, we may have no control over the timing or amount of capital expenditures associated with the project. If we are not willing or able to fund required capital expenditures relating to a project when required by the majority owner(s) or operator, our interests in the project may be reduced or forfeited. Also, we could be responsible for plugging and abandonment costs, as well as other liabilities in excess of our proportionate interest in the property.

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.

Risks Related to the Ownership of our Common Stock

OVR holds a significant number of shares of our common stock.

OVR holds a significant number of shares of our outstanding common stock. OVR is entitled to act separately in its own interest with respect to its shares of our common stock, and it has the voting power to significantly influence the election of the members of our board of directors and thereby significantly influence our management and Company affairs. In addition, OVR has the ability to significantly influence the outcome of all matters requiring stockholder approval, including mergers and other material transactions, and to cause or prevent a change in the composition of our board of directors or a change in control of the Company that could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of the Company. The existence of a significant stockholder may adversely affect matters that could be in the best interests of minority stockholders. For example, the existence of a significant stockholder could have the effect of deterring hostile takeovers or other bona-fide purchase proposals, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of the Company. However, approval of the

Bold Contribution Agreement requires the approval of both a majority of shareholders and a majority of minority stockholders, which excludes the shares held by OVR.

So long as OVR continues to control a significant amount of our common stock, OVR will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of OVR may differ or conflict with the interests of our other stockholders. Moreover, this concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder. As of March 1, 2017, OVR controls 9,162,452 shares of our common stock, or 41.1% of the outstanding shares.

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

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

In addition, the stock market in general and the market for upstream oil and natural gas 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 upstream 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.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Oil and Natural Gas Reserves

All of our oil and natural gas reserves are located in the United States. Our reserve estimates have been prepared by Cawley, Gillespie & Associates, Inc. ("CG&A"), an independent petroleum engineering firm. The scope and results of CG&A's procedures are summarized in a letter which is included as an exhibit to this report. For further information on estimated reserves, including information on estimated future net cash flows and the standardized measure of discounted future net cash flows, please refer to the *Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)* within Part II, Item 8 of the Notes to Consolidated Financial Statements of this report.

2016 Increases / Decreases in Proved Reserves

From January 1, 2016 to December 31, 2016, our total estimated proved reserves decreased 4% from 12,574 MBOE to 12,051 MBOE. Of that, estimated proved developed reserves increased 9% from 8,613 MBOE to 9,361 MBOE and estimated proved undeveloped reserves decreased 32% from 3,961 MBOE to 2, 690 MBOE

Proved Reserves as of December 31, 2016

The below table sets forth a summary of our estimated crude oil, natural gas and natural gas liquids reserves as of December 31, 2016 based on the annual reserve estimate prepared by CG&A. In preparing this reserve report, CG&A evaluated 100% of our properties at December 31, 2016. Proved reserves are estimated based on the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period for the year. All prices and costs associated with operating wells were held constant in accordance with the SEC guidelines.

	Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	Total (MBOE) (1)	Present Value Discounted at 10% ($ in thousands)
Proved developed	6,052	13,545	1,051	9,361	$ 83,242
Proved undeveloped	1,059	6,856	488	2,690	2,641
Total proved	7,111	20,401	1,539	12,051	$ 85,883

(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). Natural gas liquids have been converted to MBbls.

PV-10 is a non-GAAP measure that differs from a measure under accounting principles generally accepted in the United States ("GAAP") known as "standardized measure of discounted future net cash flows" in that PV-10 is calculated without including future income taxes. Management believes that the presentation of the PV-10 value of its oil and natural gas properties 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. We believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies because the timing and quantification of future income taxes is dependent on company-specific factors, many of which are difficult to discern presently. For these reasons, management uses and believes that the industry generally uses the PV-10 measure in evaluating and comparing acquisition candidates and assessing the potential rate of return on investments in oil and natural gas properties. PV-10 does not necessarily represent the fair market value of oil and natural gas properties. PV-10 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.

The table below provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows (*in thousands*):

Present value of estimated future net revenues (PV-10)	$ 85,883
Future income taxes, discounted at 10%	—
Standardized measure of discounted future net revenues	$ 85,883

Proved Undeveloped Reserves

Proved undeveloped reserves decreased 1,271 MBOE or 32%, for the year ended December 31, 2016 compared to the year ended December 31, 2015. Revisions of prior estimates reflect the reduction in commodity prices from 2015 to 2016. Certain previously booked PUDs were reclassified as proved developed reserves due to successful drilling efforts. Revisions of prior estimates also include certain PUDs that were reclassified to unproved categories due to development plan changes. In accordance with our 2016 year-end independent engineering reserve report, we plan to drill all of our individual PUD drilling locations within the next five years.

The following table details the changes in our estimated proved undeveloped reserves for year ended December 31, 2016 (*in MBOE*):

Proved undeveloped reserves at December 31, 2015	3,961
Conversions to developed	(169)
Extensions and discoveries	293
Purchases	873
Revisions	(2,268)
Proved undeveloped reserves at December 31, 2016	2,690

Conversions. In 2016, all 169 MBOE of the reserve conversions occurred in our non-operated Bakken/Three Forks program in North Dakota.

Extensions and discoveries. During 2016, we added 293 MBOE of PUDs through extensions and discoveries, primarily as a result of successful drilling in our operated Eagle Ford properties in Fayette and Gonzales Counties, Texas and our non-operated Bakken/Three Forks program in North Dakota.

Purchases. During 2016, all of our purchases of PUD reserves were as a result of our acquisition of Lynden Energy Corp, which included interests in non-operated Midland Basin properties in Glasscock, Howard, Martin and Midland Counties, Texas.

Revisions. In 2016, the downward revisions of 2,268 MBOE to PUD reserves occurred primarily as a result of decreased oil and natural gas prices, which decreased the number of economic PUD locations and the corresponding reserves.

Preparation of Reserve Estimates

We engaged an independent petroleum engineering consulting firm, CG&A, to prepare our annual reserve estimates and we have relied on CG&A's expertise to ensure that our reserve estimates are prepared in compliance with SEC guidelines.

The technical person primarily responsible for the preparation of the reserve report is Mr. W. Todd Brooker, Senior Vice President of CG&A. He graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum engineering. Mr. Brooker is a Registered Professional Engineer in Texas and has more than 25 years of experience in the estimation and evaluation of oil and natural gas reserves. He is also a member of the Society of Petroleum Engineers.

Mr. Anderson, our Executive Vice President responsible for reservoir engineering, is a qualified reserve estimator and auditor and is primarily responsible for overseeing CG&A during the preparation of our annual reserve estimates. 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 Natural Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include a Bachelor of Science degree in Petroleum Engineering from the University of Wyoming in 1986; a Master of Business Administration degree from the University of Denver in 1988; member of the Society of Petroleum Engineers since 1985; and more than 30 years of practical experience in estimating and evaluating reserve information with more than five of those years being in charge of estimating and evaluating reserves.

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, at least, annually, is assessed for validity when CG&A has technical meetings with our engineers, geologists, 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. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in *Internal Control – Integrated Framework*, (2013 Version) issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 our personnel 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, CG&A 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 CG&A so that it can prepare its independent reserve estimates and final report. The reserve estimates prepared by CG&A are reviewed and compared to our internal estimates by our Executive Vice President responsible for reservoir engineering. Material reserve estimation differences are reviewed between CG&A and us, and additional data is provided to address the differences. If the supporting documentation will not justify additional changes, the CG&A reserves are accepted. In the event that additional data supports a reserve estimation adjustment, CG&A will analyze the additional data, and may make changes it solely 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 CG&A.

Net Oil, Natural Gas and Natural Gas Liquids Production, Average Price and Average Production Cost

The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2016, 2015, and 2014, the average sales price per unit sold and the average production cost per unit are presented below.

	Years Ended December 31,		
	2016	2015	2014
Sales Volumes:			
Oil (MBbl)	878	904	403
Natural gas (MMcf)	2,171	2,143	2,132
Natural gas liquids (MBbl)	225	176	124
Barrels of oil equivalent (MBOE)*	1,465	1,437	882
Average prices realized:**			
Oil (per Bbl)	$ 39.13	$ 44.09	$ 86.29
Natural gas (per Mcf)	$ 2.32	$ 2.55	$ 4.39
Natural gas liquids (per Bbl)	$ 12.74	$ 12.29	$ 28.29
Barrels of oil equivalent (per BOE)	$ 28.86	$ 33.04	$ 53.99
Production cost per BOE***	$ 10.06	$ 10.72	$ 11.39

* 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). Natural gas liquids have been converted to MBbls.

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting. Our derivatives for 2016, 2015 and 2014 have been marked-to-market in our Consolidated Statements of Operations as other income/expense; which means that all our realized gains/losses on these derivatives are reported in other income/expense.

*** Transportation costs remain included in these amounts, but exclude ad valorem taxes, which are included in lease operating expenses in our Consolidated Statements of Operations. Ad valorem taxes were $0.5 million, $0.3 million and $0.5 million in 2016, 2015 and 2014, respectively.

As of December 31, 2016, five fields accounted for approximately 90% of our total estimated proved reserves. Spraberry Trend field, which was acquired in May 2016 as part of our Lynden acquisition, accounted for 26% of our total estimated proved reserves. The Banks field, which was acquired as part of our transaction with OVR in December 2014, was 13% of our total estimated proved reserves. Southern Bay Eagle Ford and Eagleville fields accounted for 19% and 13%, respectively, of our total estimated proved reserves, and the Hawkville field accounted for 19% of our total estimated proved reserves. No other single field accounted for 15% or more of our total estimated proved reserves as of December 31, 2016, 2015 or 2014. The net quantities of oil, natural gas and natural gas liquids produced and sold by us from these significant fields for each of the years ended December 31, 2016, 2015 and 2014, the average sales price per unit sold and the average production cost per unit are presented below.

Southern Bay Eagle Ford Field (Fa yette County, Texas)

	Years Ended December 31,		
	2016	2015	2014
Sales Volumes:			
Oil (MBbl)	254	653	210
Natural gas (MMcf)	120	229	85
Natural gas liquids (MBbl)	36	68	23
Barrels of oil equivalent (MBOE)*	310	759	247
Average prices realized:**			
Oil (per Bbl)	$ 38.95	$ 45.68	$ 87.75
Natural gas (per Mcf)	$ 2.33	$ 2.58	$ 4.25
Natural gas liquids (per Bbl)	$ 13.58	$ 13.01	$ 28.98
Barrels of oil equivalent (per BOE)	$ 34.38	$ 41.25	$ 78.80
Production cost per BOE***	$ 8.32	$ 6.89	$ 6.96

* 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). Natural gas liquids have been converted to MBbls.

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

*** Transportation costs remain included in these amounts, but exclude ad valorem taxes.

Eagleville Field (Eagle Ford – Karnes County, Texas)

	Years Ended December 31,		
	2016	2015	2014
Sales Volumes:			
Oil (MBbl)	216	175	70
Natural gas (MMcf)	60	49	25
Natural gas liquids (MBbl)	16	15	7
Barrels of oil equivalent (MBOE)*	242	198	81
Average prices realized:**			
Oil (per Bbl)	$ 40.54	$ 44.75	$ 84.58
Natural gas (per Mcf)	$ 2.37	$ 2.58	$ 4.36
Natural gas liquids (per Bbl)	$ 13.07	$ 13.14	$ 30.24
Barrels of oil equivalent (per BOE)	$ 37.59	$ 41.13	$ 77.57
Production cost per BOE***	$ 5.25	$ 5.96	$ 9.16

* 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). Natural gas liquids have been converted to MBbls.

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

*** Transportation costs remain included in these amounts, but exclude ad valorem taxes.

Banks Field (Bakken – McKenzie County, North Dakota)

No results have been included for 2014 as the field was acquired as part of a December 2014 Exchange.

	Years Ended December 31,	
	2016	2015
Sales Volumes:		
Oil (MBbl)	109	126
Natural gas (MMcf)	194	230
Natural gas liquids (MBbl)	27	32
Barrels of oil equivalent (MBOE)*	168	196
Average prices realized:**		
Oil (per Bbl)	$ 30.60	$ 40.29
Natural gas (per Mcf)	$ 2.19	$ 2.69
Natural gas liquids (per Bbl)	$ 5.47	$ 7.98
Barrels of oil equivalent (per BOE)	$ 23.19	$ 30.28
Production cost per BOE***	$ 6.54	$ 8.31

* 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). Natural gas liquids have been converted to MBbls.

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

*** Transportation costs remain included in these amounts, but exclude ad valorem taxes.

Hawkville Field (Eagle Ford – La Salle County)

	Years Ended December 31,		
	2016	2015	2014
Sales Volumes:			
Oil (MBbl)	13	18	34
Natural gas (MMcf)	736	943	947
Natural gas liquids (MBbl)	57	76	85
Barrels of oil equivalent (MBOE)*	193	251	280
Average prices realized:**			
Oil (per Bbl)	$ 27.26	$ 31.69	$ 82.34
Natural gas (per Mcf)	$ 2.40	$ 2.61	$ 4.45
Natural gas liquids (per Bbl)	$ 12.26	$ 13.46	$ 27.72
Barrels of oil equivalent (per BOE)	$ 14.61	$ 16.18	$ 33.62
Production cost per BOE***	$ 8.53	$ 11.66	$ 11.08

* 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). Natural gas liquids have been converted to MBbls.

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

*** Transportation costs remain included in these amounts, but exclude ad valorem taxes.

Spraberry Trend (Midland Basin Properties)

No results for 2015 or 2014 have been included as the field was acquired as part of the Lynden Arrangement in 2016.

	Year Ended December 31,	
	2016	
Sales Volumes:		
Oil (MBbl)		139
Natural gas (MMcf)		352
Natural gas liquids (MBbl)		68
Barrels of oil equivalent (MBOE)*		266
Average prices realized: **		
Oil (per Bbl)	$	45.07
Natural gas (per Mcf)	$	2.43
Natural gas liquids (per Bbl)	$	15.73
Barrels of oil equivalent (per BOE)	$	30.83
Production cost per BOE***	$	9.92

* 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). Natural gas liquids have been converted to MBbls.

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

*** Transportation costs remain included in these amounts, but exclude ad valorem taxes.

Our oil production is sold to large purchasers. Due to the quality and location of our oil production, we may receive a discount or premium from index prices or "posted" prices in the area. Our natural gas production is sold primarily to pipeline companies and/or gas marketers under short-term contracts at prices which are tied to the "spot" market for natural gas sold in the area.

The purchasers of our oil, natural gas and natural gas liquids production consist primarily of independent marketers, major oil and natural gas companies and pipeline companies. In 2016, two purchasers accounted for 41% and 19%, respectively, of our oil, natural gas and natural gas liquids revenues. In 2015 and 2014, one purchaser, accounted for 62% and 60%, respectively, of our oil, natural gas and natural gas liquids revenues. These purchasers are expected to be a significant purchasers in the future as well. No other purchaser accounted for 10% or more of our oil, natural gas and natural gas liquids revenues during 2016, 2015 and 2014.

We hold working interests in oil and natural gas properties for which third parties serve as operator. The operator sells the oil, natural gas and natural gas liquids to the purchaser, and collects and distributes the revenue to us. In 2016 and 2015, one operator accounted for 19% and 12%, respectively of our total oil, natural gas and natural gas liquids revenues. In 2014, a different operator accounted for 20% of our total oil, natural gas and natural gas liquids revenues. No other operator accounted for 10% or more of our oil, natural gas and natural gas liquids revenues during the years ended December 31, 2016, 2015 and 2014.

Gross and Net Productive Wells

As of December 31, 2016, 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
462	135	164	50	626	185

(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.

Gross and Net Developed and Undeveloped Acres

As of December 31, 2016, we had estimated 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 working interest is owned. The number of net acres represents the sum of fractional working interests we own in gross acres.

State	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas	75,400	27,700	135,900	67,000	211,300	94,700
Oklahoma	16,200	13,900	—	—	16,200	13,900
Montana	6,200	2,200	4,700	1,100	10,900	3,300
North Dakota	21,600	2,500	6,800	3,400	28,400	5,900
Wyoming	600	300	1,400	600	2,000	900
Nebraska	—	—	18,400	8,300	18,400	8,300
All Others	3,500	2,500	16,300	600	19,800	3,100
Total	123,500	49,100	183,500	81,000	307,000	130,100

Out of a total of 183,500 gross (81,000 net) undeveloped acres as of December 31, 2016, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 77% in 2017, 19% in 2018 and 4% in 2019 and beyond. The portion of our net undeveloped acres related to the Eagle Ford acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 7% in 2017, 9% in 2018 and 4% in 2019 and beyond. We anticipate that within our Eagle Ford acreage, our current and future drilling plans, along with the selected lease extensions, will address the majority of the leases expiring in 2017 and beyond.

Exploratory Wells and Development Wells

Set forth below for the three years ended December 31, 2016 is information concerning the number of wells we drilled during the years indicated.

Year	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells
	Productive	Dry	Productive	Dry	Drilled
2016	—	—	7.7	—	7.7
2015	—	—	7.2	—	7.2
2014	—	—	7.3	—	7.3

Present Activities

As of March 1, 2017, we have 16 gross (2.1 net) non-operated wells in the process of drilling or completing.

Item 3. Legal Proceedings

In the ordinary course of business, we may be involved in litigation and claims arising out of our operations. As of December 31, 2016, and through the filing date of this report, we do not believe the ultimate resolution of any such actions or potential actions of which we are currently aware will have a material effect on our consolidated financial position or results of operations.

A description of our legal proceedings is included in *Note. 14. Commitments and Contingencies* included in Item 8 of this report.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Company

The following table sets forth, as of March 1, 2017, certain information regarding the executive officers of Earthstone:

Name	Age	Position
Frank A Lodzinski	67	President and Chief Executive Officer
Tony Oviedo	63	Executive Vice President, Accounting and Administration (Principal Accounting Officer)
Ray Singleton	65	Executive Vice President, Northern Region
Robert J. Anderson	55	Executive Vice President, Corporate Development and Engineering
Steve C. Collins	52	Executive Vice President, Completions and Operations
Christopher E. Cottrell	56	Executive Vice President, Land and Marketing and Corporate Secretary
Timothy D. Merrifield	61	Executive Vice President, Geological and Geophysical
Francis M. Mury	65	Executive Vice President, Drilling and Development

The following biographies describe the business experience of our executive officers:

Frank A. Lodzinski has served as our Chairman, President and Chief Executive Officer since December 2014. Previously, he served as President and Chief Executive Officer of OVR from its formation in December 2012 until the closing of its strategic combination with us in December 2014. Prior to his service with OVR, Mr. Lodzinski was Chairman, President and Chief Executive Officer of GeoResources, Inc. from April 2007 until its merger with Halcón Resources Corporation ("Halcón") in August 2012 and from September 2012 until December 2012 he conducted pre-formation activities for OVR. He has over 43 years of oil and gas industry experience. In 1984, he formed Energy Resource Associates, Inc., which acquired management and controlling interests in oil and gas limited partnerships, joint ventures and producing properties. Certain partnerships were exchanged for common shares of Hampton Resources Corporation in 1992, which Mr. Lodzinski joined as a director and President. Hampton was sold in 1995 to Bellwether Exploration Company. In 1996, he formed Cliffwood Oil & Gas Corp. and in 1997, Cliffwood shareholders acquired a controlling interest in Texoil, Inc., where Mr. Lodzinski served as a director, Chief Executive Officer and President. In 2001, Mr. Lodzinski was appointed Chief Executive Officer and President of AROC, Inc., to direct the restructuring and ultimate liquidation of that company. In 2003, AROC completed a monetization of oil and gas assets with an institutional investor and began a plan of liquidation. In 2004, Mr. Lodzinski formed Southern Bay Energy, LLC, the general partner of Southern Bay Oil & Gas, L.P., which acquired the residual assets of AROC, Inc., and he served as President of Southern Bay Energy, LLC. The Southern Bay entities were merged into GeoResources in April 2007. Mr. Lodzinski has served as a director of Yuma Energy, Inc. since September 2014. He also served as a member of the Audit Committee from September 2014 until October 2016. In October 2016, he was appointed a member of the Compensation Committee. He holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

Tony Oviedo was appointed as our Executive Vice President – Accounting and Administration (Principal Accounting Officer) in January 25, 2017, effective February 10, 2017. Mr. Oviedo has over 30 years of professional experience with both private and public companies. Prior to joining Earthstone, he was employed by GeoMet, Inc., where, since 2006, he had served as the Senior Vice President, Chief Financial Officer, Chief Accounting Officer and Controller. In addition, prior to joining GeoMet, Mr. Oviedo was employed by Resolution Performance Products, LLC, where he was Compliance Director and has held positions as Chief Accounting Officer, Controller, and Director of Financial Reporting with various companies in the oil and gas industry. Prior to the aforementioned experience, he served in the audit practice of KPMG LLP's Energy Group. Mr. Oviedo holds a Bachelor's degree in Business Administration with a concentration in accounting and tax from the University of Houston and is a Certified Public Accountant in the state of Texas.

Ray Singleton is a petroleum engineer with over 37 years of experience in the oil and gas industry. He has been one of our directors since July 1989 and was our President and Chief Executive Officer from March 1993 until December 2014. Since December 2014, he has served as our Executive Vice President, Northern Region. Mr. Singleton joined us in 1988 as a Production Manager/Petroleum Engineer. From 1983 until 1988, he owned and operated an engineering consulting firm (Singleton & Associates) serving the needs of 40 small oil and gas clients. During this period, he was engaged by Earthstone on various projects in south Texas and the Rocky Mountain region. Mr. Singleton began his career with Amoco Production Company in 1973 as a production engineer in Texas. He was subsequently employed by the predecessor of Union Pacific Resources as a drilling, completion and production engineer from 1980 to 1983. His professional experience includes acquisition evaluation and economics, reserve engineering and drilling, completion and production engineering in both Texas and the Rocky Mountain region. In addition, he possesses over 21 years of executive experience and has an intimate knowledge of Earthstone's legacy Rocky Mountain and south Texas properties. Mr. Singleton received a B.S. degree in Petroleum Engineering from Texas A&M University in 1973, and received an MBA from Colorado State University's Executive MBA Program in 1992.

Robert J. Anderson is a petroleum engineer with over 30 years of diversified domestic and international oil and gas experience. He has served as our Executive Vice President, Corporate Development and Engineering since December 2014. Previously, he served in a similar capacity with OVR from March 2013 until the closing of its strategic combination with Earthstone in December 2014. Prior to joining OVR, he served from August 2012 to February 2013 as Executive Vice President and Chief Operating Officer of Halcón. Mr. Anderson was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012, ultimately serving as a director and Executive Vice President, Chief Operating Officer – Northern Region. He was involved in the formation of Southern Bay Energy in September 2004 as Vice President, Acquisitions until its merger with GeoResources in April 2007. From March 2004 to August 2004, Mr. Anderson was employed by AROC, a predecessor company to Southern Bay Energy, as Vice President, Acquisitions and Divestitures. From September 2000 to February 2004, he was employed by Anadarko Petroleum Corporation as a petroleum engineer. In addition, he has worked with major oil companies, including ARCO International/Vastar Resources, and independent oil companies, including Hunt Oil, Hugoton Energy, and Pacific Enterprises Oil Company. His professional experience includes acquisition evaluation, reservoir and production engineering, field development, project economics, budgeting and planning, and capital markets. His domestic acquisition and divestiture experience includes Texas and Louisiana (offshore and onshore), Mid-Continent, and the Rocky Mountain states, and his international experience includes Canada, South America, and Russia. Mr. Anderson has a B.S. degree in Petroleum Engineering from the University of Wyoming and an MBA from the University of Denver

Steven C. Collins is a petroleum engineer with over 28 years of operations and related experience. He has served as our Executive Vice President, Completions and Operations since December 2014. Previously, he served in a similar capacity with OVR from its formation in December 2012 until the closing of its strategic combination with Earthstone in December 2014. Prior to employment by OVR, he served from August 2012 to November 2012 as a consultant to Halcón. Mr. Collins was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012 and directed field operations, including well completion, production and workover operations. Prior to employment by GeoResources, he served as Vice President of Operations for Southern Bay, AROC, and Texoil, and as a petroleum and operations engineer at Hunt Oil Company and Pacific Enterprises Oil Company. His experience includes Texas, Louisiana (onshore and offshore), North Dakota, Montana, and the Mid-Continent. Mr. Collins graduated with a B.S. degree in Petroleum Engineering from the University of Texas.

Christopher E. Cottrell has over 33 years of oil and gas industry experience. He has served as our Executive Vice President, Land and Marketing and Corporate Secretary since December 2014. Previously, he served in a similar capacity with OVR from its formation in December 2012 until the closing of its strategic combination with Earthstone in December 2014. Prior to employment by OVR, he was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012, ultimately serving as Vice President of Land and Marketing, responsible for land and operating contract matters including oil and gas marketing, land and lease records, title and division orders. In addition, he was actively involved in due diligence associated with business development matters. He has held previous roles at AROC, Texoil, Williams Exploration, Ashland Exploration, American Exploration, Belco Energy, and Citation Oil & Gas. Mr. Cottrell graduated with a B.B.A. degree in Petroleum Land Management from the University of Texas.

Timothy D. Merrifield has over 37 years of oil and gas industry experience. He has served as our Executive Vice President, Geology and Geophysics since December 2014. Previously, he served in a similar capacity with OVR from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. Prior to employment by OVR, he served from August 2012 to November 2012 as a consultant to Halcón upon its merger with GeoResources, Inc. in August 2012. From April 2007 to August 2012, Mr. Merrifield led all geology and geophysics efforts at GeoResources. He has held previous roles at AROC, Force Energy, Great Western Resources and other independents. His domestic experience includes Texas, Louisiana (onshore and offshore), North Dakota, Montana, New Mexico, Rocky Mountain States, and the Mid-Continent. In addition, he has international experience in Peru and the East Irish Sea. Mr. Merrifield attended Texas Tech University.

Francis M. Mury has over 42 years of oil and gas industry experience. He has served as our Executive Vice President, Drilling and Development since December 2014. Previously, he served in a similar capacity with OVR from its formation in December 2012 until the closing of its strategic combination with Earthstone in December 2014. Prior to employment by OVR, he was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012, ultimately serving as an Executive Vice President, Chief Operating Officer–Southern Region. He has held prior roles at AROC, Texoil, Hampton Resources, Wainoco Oil & Gas Company, Diasu Exploration Company, and Texaco, Inc. His experience extends to all facets of petroleum engineering, including reservoir engineering, drilling and production operations, petroleum economics, geology, geophysics, land, and joint operations. Geographical areas of experience include Texas and Louisiana (offshore and onshore), North Dakota, Montana, Mid-Continent, Florida, New Mexico, Oklahoma, Wyoming, Pennsylvania and Michigan. Mr. Mury graduated from Nicholls State University with a degree in Computer Science.

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

Market Information for Common Stock

Shares of our common stock are traded on the NYSE MKT under the symbol "ESTE." The following table sets forth the reported high and low sales prices of our common stock for the period indicated:

	Common Stock Price	
Period	**High**	**Low**
2016		
First Quarter	$ 14.19	$ 10.75
Second Quarter	$ 15.93	$ 10.12
Third Quarter	$ 11.66	$ 7.67
Fourth Quarter	$ 15.71	$ 8.02
2015		
First Quarter	$ 31.00	$ 19.40
Second Quarter	$ 28.90	$ 17.65
Third Quarter	$ 20.15	$ 12.11
Fourth Quarter	$ 18.50	$ 12.99

Holders

As of March 1, 2017, there were approximately 1,800 holders of record of our common stock.

Dividends

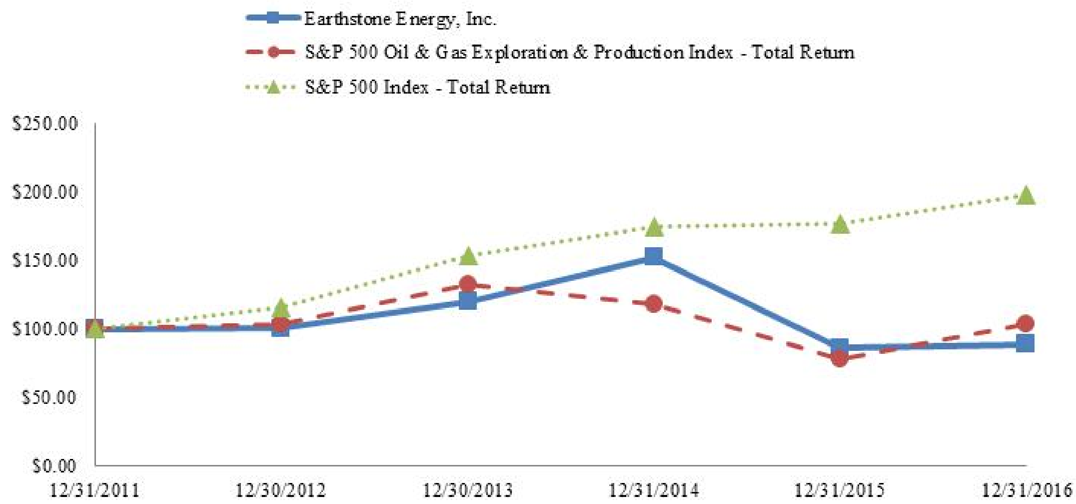
We have never paid dividends on our common stock and do not intend to pay a dividend in the foreseeable future. Furthermore, our credit agreement with our bank restricts the payment of cash dividends. The payment of future cash dividends on common stock, if any, will be reviewed periodically by our board of directors and will depend upon, but not be limited to, our financial condition, funds available for operations, the amount of anticipated capital and other expenditures, our future business prospects and any restrictions imposed by our present or future financing arrangements.

Repurchase of Equity Securities

We did not repurchase any of our shares of common stock during the year ended December 31, 2016.

Performance Graph

The following graph reflects a comparison of the cumulative total stockholder return of our common stock beginning December 31, 2011 through December 31, 2016, relative to the cumulative total returns of the S&P 500 Index and the S&P Oil & Gas Exploration & Production Select Industry Index. The graph assumes the investment of $100 on December 31, 2011 in our common stock and each index and the reinvestment of all dividends, if any. The identity of the companies included in the S&P Oil & Gas Exploration & Production Select Industry Index will be provided upon request.



	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016
Earthstone Energy, Inc.	$ 100.00	$ 100.32	$ 119.82	$ 152.20	$ 86.20	$ 88.99
S&P 500 Index - Total Return	$ 100.00	$ 116.00	$ 153.57	$ 174.60	$ 177.01	$ 198.18
S&P 500 Oil & Gas Exploration & Production Index - Total Return	$ 100.00	$ 103.65	$ 132.14	$ 118.15	$ 77.80	$ 103.36

Item 6. Selected Financial Data

The following selected financial data should be read in conjunction with Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, and our consolidated financial statements and the accompanying notes thereto included elsewhere in this report. In accordance with GAAP, the consolidated financial information and consolidated financial statements included herein for 2014 and prior period, are those of OVR and its subsidiaries. Prior to the Exchange, OVR, and its subsidiaries were pass through entities for income tax purposes and therefore no income tax expense was recorded for the historical periods prior to the year ended December 31, 2014. OVR is an entity formed in December 2012 that was initially capitalized through the contribution of producing properties, acreage and working capital as well as cash commitments from investors. Upon initial capitalization, the contributed properties, acreage and working capital resulted in one owner retaining a controlling interest in OVR, and despite a change in management, GAAP required OVR to the record the contributed properties at their historical cost basis even though such cost basis was in excess of the valuation agreed upon by members at the time of capitalization. GAAP required reporting higher DD&A provisions and significant impairments, in all years presented below, than would have been reported otherwise had the properties been recorded at the agreed upon valuation approximating fair value.

(In thousands, except per share and production amounts)	Years ended December 31,				
Summary of Operating Data	**2016**	**2015**	**2014**	**2013**	**2012**
Production					
Oil (MBbl)	878	904	403	163	90
Natural gas (MMcf)	2,171	2,143	2,132	2,635	2,298
Natural gas liquids (MBbl)	225	176	124	134	76
Barrel of oil equivalent (MBOE)*	1,465	1,437	882	737	549
Average realized prices:					
Oil (per Bbl)	$ 39.13	$ 44.09	$ 86.29	$ 98.32	$ 96.00
Natural gas (per Mcf)	$ 2.32	$ 2.55	$ 4.39	$ 3.69	$ 2.64
Natural gas liquids (per Bbl)	$ 12.74	$ 12.29	$ 28.29	$ 28.88	$ 31.00
Summary of Operations:					
Total revenues	$ 42,269	$ 47,464	$ 47,611	$ 29,634	$ 17,091
Lease operating, re-engineering and workover expenses	$ 15,067	$ 15,422	$ 10,130	$ 8,122	$ 6,183
Severance taxes	$ 2,198	$ 2,582	$ 2,002	$ 1,225	$ 608
Impairment expense	$ 24,283	$ 138,086	$ 19,359	$ 12,298	$ 52,475
Depreciation, depletion and amortization	$ 25,937	$ 31,228	$ 18,414	$ 17,111	$ 12,191
Pretax loss	$ (54,013)	$ (143,097)	$ (6,729)	$ (19,875)	$ (53,321)
Income tax expense (benefit)	$ 528	$ (26,442)	$ 22,105	$ —	$ —
Net loss	$ (54,541)	$ (116,655)	$ (28,834)	$ (19,875)	$ (53,321)
Net loss per share:**					
Basic	$ (2.92)	$ (8.43)	$ (3.11)	$ (2.18)	$ (5.84)
Diluted	$ (2.92)	$ (8.43)	$ (3.11)	$ (2.18)	$ (5.84)
Summary Balance Sheet Data at Year End :					
Net oil and natural gas properties	$ 269,402	$ 198,333	$ 295,877	$ 147,297	$ 63,462
Total assets	$ 316,512	$ 264,944	$ 451,388	$ 189,858	$ 87,542
Long-term debt	$ 12,693	$ 11,191	$ 11,191	$ 10,825	$ 10,825
Total equity	$ 241,457	$ 199,873	$ 316,528	$ 148,922	$ 61,267

* Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equals one barrel of oil equivalent (BOE).

** For periods prior to the Exchange, earnings per share is calculated based on 9,124,452 shares which is the number of shares issued to OVR in December 2014 as a result of the Exchange.

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

The following discussion of our financial condition, results of operations, liquidity and capital resources should be read together with our consolidated financial statements and the notes to consolidated financial statements, both of which are included in this report under Item 8, as well as the information set forth in *Risk Factors* under Item 1A. Unless the context otherwise requires, the terms " the Company", "our", "we", "us", and "Earthstone" refer to Earthstone Energy, Inc. and its consolidated subsidiaries.

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*.

Executive Overview

Strategy and 2017 Outlook

We are a growth-oriented independent oil and gas company engaged in the acquisition and development of oil and gas reserves through an active and diversified program that includes the acquisition, drilling and development of undeveloped leases, asset and corporate acquisitions and, to a lesser extent, exploration activities, with our current primary assets located in the Midland Basin of west Texas, the Eagle Ford trend of south Texas and the Williston Basin of North Dakota. Future growth in assets, earnings, cash flows and common share values will be dependent upon our ability to acquire, discover and develop commercial quantities of oil and natural gas reserves that can be produced for a profit and to assemble an oil and natural gas reserve base with an estimated market value exceeding its acquisition, development and production costs. Historically, we have operated in more than one basin and have shifted our capital expenditures among basins to take advantage of regional changes in market conditions, such as commodity prices (net of transportation differentials) and availability and costs of services and equipment, thus promoting profitable growth. With the closing of the Bold Contribution Agreement, we will direct the majority of our capital budget to the Permian Basin. The majority of our efforts are currently focused on development of our acreage positions in our primary asset locations. In addition, it is essential that, over time, our personnel expand our current projects and/or generate additional projects so that we have the potential to economically replace our production and increase our estimated proved reserves.

The impact of the recent oil and gas price downturn, which began in 2014, may have long-term effects on our business, as well as the industry as a whole. Despite the prevailing low oil and natural gas prices, we believe we were able to achieve certain accretive Company goals in 2016 which included, but were not limited to:

- converting a large portion of our acreage to held by production (“HBP”) status, while improving our lease expiration profile to minimize near-term lease expirations;
- lowering our operating costs and general and administrative costs, in total and on a unit of production basis;
- increasing efficiencies and significantly decreasing our drilling and completion costs, generally beyond reductions in the prevailing in the industry;
- completing a corporate acquisition, with production and undeveloped acreage that is substantially all HBP and which facilitated our initial entry into the Permian Basin, and
- executing the Bold Contribution Agreement, which when closed will significantly expand our Permian Basin holdings and establish us as an operator with added current production and a substantial drilling inventory on leases that are largely HBP.

At December 31, 2016, approximately 74% of our operated Eagle Ford and substantially all our Bakken acreage was held-by-production. Of the approximately 9,900 remaining total gross undeveloped acres prospective for the Eagle Ford, Upper Eagle Ford, Austin Chalk and possibly other objectives, approximately 4,700 net acres could expire in 2017. We anticipate that our current and future drilling plans, along with the selected lease extensions, will extend the majority of the leases scheduled to expire.

For 2017, we intend to conduct operations within our available cash flows and availability under our reserve-based Credit Agreement. We expect to resume our drilling and completion operations in our operated Eagle Ford project in Gonzales County in the second quarter of 2017 along with selected participations in non-operated activities in west Texas and in North Dakota. While conducting these operations within our available liquidity, we will continue to pursue our business strategy. Following is a brief outline of our current plans:

- pursue attractive asset or corporate acquisitions;
- maintain and expand our acreage positions and drilling inventory;

- pending adequate commodity prices, continue the development of our acreage positions in the Eagle Ford trend of south Texas, horizontal Wolfcamp trend of west Texas and the Williston Basin of North Dakota;
- generate additional oil-weighted development projects; and
- obtain additional capital as available and needed, or offer our common stock in exchange for acquisitions.

Bold Contribution Agreement

On November 7, 2016, we entered into a contribution agreement (the "Bold Contribution Agreement"), by and among the Company, Earthstone Energy Holdings, LLC, a newly formed Delaware limited liability company ("EEH"), Lynden USA, Inc., a Utah corporation ("Lynden USA"), Lynden USA Operating, LLC, a newly formed Texas limited liability company (all wholly-owned subsidiaries of the Company), Bold Energy Holdings, LLC, a Texas limited liability company ("Bold Holdings"), and Bold Energy III LLC, a Texas limited liability company ("Bold").

Under the Bold Contribution Agreement, the terms of which were unanimously approved by a special committee of disinterested members of the Company's Board of Directors and the full Board (i) the Company will recapitalize the Common Stock into two classes, consisting of Class A and Class B, and all of its existing Common Stock will be converted into Class A common stock. Bold Holdings will purchase approximately 36.1 million shares of the Company's Class B common stock for nominal consideration, with the Class B common stock having no economic rights in the Company other than voting rights on a pari passu basis with the Class A common stock. In addition, EEH will issue approximately 22.3 million of its membership units to the Company and Lynden USA, in the aggregate, and approximately 36.1 million membership units to Bold Holdings in exchange for each of the Company, Lynden USA and Bold Holdings transferring all of their assets to EEH; and (iii) each Bold membership unit in EEH, together with one share of Bold Holdings Class B common stock, will be convertible into Class A common stock on a one-for-one basis. Therefore, upon the closing of the transaction, stockholders of the Company and unitholders of Bold Holdings are expected to own approximately 39% and 61%, respectively of the combined company's then outstanding Class A and Class B common stock on a fully diluted basis. After closing, the Company expects conduct its activities through EEH and will be its sole managing member. The transaction is expected to close in the second quarter of 2017 and is subject to approval of the Company's stockholders and other customary closing conditions

Commodity Prices:

The up-stream oil and natural gas business has historically been cyclical and we are currently operating in a low commodity price environment. Our consolidated average realized prices for 2016 decreased approximately 11% for crude oil, 9% for natural gas and slightly increased 4% for natural gas liquids compared to 2015. These low prices resulted in a reduction in our capital spending program, had significant negative impacts on our revenues, profitability, cash flows and estimated proved reserves, resulting in asset and goodwill impairments in 2015 and 2016, and caused us to execute certain cost-saving organizational changes.

During 2016, commodities continued to trade lower than Management's expectation, with crude oil prices falling during the first quarter below $30 per barrel on some occasions. Beginning in the second quarter of 2016 and into the third quarter, prices improved and moved into the $40 to $50 per barrel range. If the industry downturn persists or oil and natural gas prices fall back to levels experienced in the first quarter of 2016, we could experience additional material negative impacts on our revenues, profitability, cash flows, liquidity and estimated reserves, and may consider reductions in our capital expenditure program. Additionally, our production could decline further as a result of these activities. See Item 1A. *Risk Factors* in this report for further discussion.

Acquisitions and Divestitures:

In April 2015, we sold substantially all of our Louisiana properties located primarily in DeSoto and Caddo Parishes for cash consideration of approximately $3.4 million, recording a gain of approximately $1.6 million. The effective date of the transaction was March 1, 2015.

In June 2015, we acquired a 50% operated working interest in approximately 1,000 gross acres in southern Gonzales County, Texas. The acreage, acquired for future Eagle Ford development, is 100% held-by-production from two gross Austin Chalk wells. This acreage position is expected to support 13 gross Eagle Ford drilling locations.

Also during June 2015, we acquired approximately 400 gross acres in northern Karnes County, Texas, which is adjacent to our approximately 1,000 gross acres in southern Gonzales County, Texas. Subsequent trades in Karnes County reduced the gross acreage from approximately 400 gross acres to approximately 350 gross acres (approximately 117 net acres) which has allowed for longer laterals and more efficient development. We initiated drilling on this acreage during the fourth quarter of 2015, and completed these wells in 2016 with initial production early in October 2016.

Additionally, in June 2015, we acquired additional acreage and working interests in wells located within existing Bakken units primarily located in the Banks Field of McKenzie County, North Dakota, for approximately $1.4 million plus purchase price adjustments of approximately $2.0 million for the revenues, net of production taxes and operating expenses and capital costs incurred for the existing wells. The acquisition included approximately 164 net acres which allowed us to increase our working interest in approximately 41 producing wells and approximately 21 wells that were in the drilling and completion phase.

In August 2015, we acquired an approximately 33% working interest in approximately 1,650 gross acres, in southern Gonzales County, Texas for $3.3 million. This acreage supports 13 gross Eagle Ford drilling locations. We expect to initiate drilling on this acreage in the second quarter of 2017.

On May 18, 2016, we acquired Lynden Energy Corp. ("Lynden") in an all-stock transaction through an arrangement (the "Lynden Arrangement") instead of a customary merger because Lynden is incorporated in British Columbia, Canada. We acquired all the outstanding shares of common stock of Lynden through a newly formed subsidiary, with Lynden surviving in the transaction as a wholly-owned subsidiary of the Company. We issued 3,700,279 shares of our common stock to the holders of Lynden common stock in the transaction.

Results of Operations

Year ended December 31, 2016, compared to the year ended December 31, 2015

	Years Ended December 31, 2016	Years Ended December 31, 2015	Change
Sales volumes:			
Oil (MBbl)	878	904	-3%
Natural gas (MMcf)	2,171	2,143	1%
Natural gas liquids (MBbl)	225	176	28%
Barrels of oil equivalent (MBOE)	1,465	1,437	2%
Average prices realized: (1)			
Oil (per Bbl)	$ 39.13	$ 44.09	-11%
Natural gas (per Mcf)	$ 2.32	$ 2.55	-9%
Natural gas liquids (per Bbl)	$ 12.74	$ 12.29	4%
(In thousands)			
Oil revenues	$ 34,358	$ 39,849	-14%
Natural gas revenues	$ 5,046	$ 5,457	-8%
Natural gas liquids revenues	$ 2,865	$ 2,158	33%
Lease operating expense	$ 13,415	$ 14,550	-8%
Severance taxes	$ 2,198	$ 2,582	-15%
Rig idle and contract termination expense	$ 5,059	$ —	100%
Impairment expense	$ 24,283	$ 138,086	-82%
Depreciation, depletion and amortization	$ 25,937	$ 31,228	-17%
General and administrative expense	$ 9,414	$ 9,711	-3%
Stock-based compensation	$ 3,301	$ —	100%
Transaction costs	$ 2,483	$ 589	322%
Interest expense, net	$ 1,282	$ 722	78%
Loss (gain) on derivative contracts, net	$ 6,638	$ (6,431)	-203%
Income tax expense (benefit)	$ 528	$ (26,442)	-102%

(1) Prices presented exclude any effects of oil and natural gas derivatives.

Oil revenues

For the year ended December 31, 2016, oil revenues decreased by approximately $5.5 million or 14% relative to the comparable period in 2015. Of the decrease, approximately $4.5 million was attributable to a decrease in our realized price and $1.0 million was attributable to decreased volume. Our average realized price per Bbl decreased from $44.09 for the year ended December 31, 2015 to $39.13 or 11% for the year ended December 31, 2016. We had net decrease in the volume of oil sold of 26 MBbls. The Midland Basin properties we acquired in the Arrangement provided an additional 139 MBbls and our southern Gonzales and northern Karnes county assets that we acquired and began development on provided an additional 56 MBbls. These increases however, were offset by declines on our operated Eagle Ford of 197 MBbls, our non-operated Eagle Ford of 6 MBbls and Bakken/Three Forks properties of 10 MBbls. The remaining volume decrease was due to normal production declines and variability in sales volumes on our other properties mainly in Texas and North Dakota.

Natural gas revenues

For the year ended December 31, 2016, natural gas revenues decreased by $0.4 million or 8% relative to the comparable period in 2015. Substantially all of the $0.4 million decrease was attributable to the decrease in our realized price. Our average realized price per Mcf decreased from $2.55 for the year ended December 31, 2015 to $2.32 or 9% for the year ended December 31, 2016. The total volume of natural gas produced and sold remained relatively consistent and increased by only 28 MMcf in total.

Natural gas liquids revenues

For the year ended December 31, 2016, natural gas liquids revenues increased by $0.7 million or 33% relative to the comparable period in 2015. Substantially all of the $0.7 million increase was attributable to the increase in volumes produced and sold. The volume of natural gas liquids produced and sold increased by 49 MBbls or 28%. The Midland Basin properties we acquired in the Lynden Arrangement and our southern Gonzales and northern Karnes county assets that we acquired and began development on provided an additional 72 MBbls. These increases were primary offset by declines on our non-operated Eagle Ford property.

Lease operating expense ("LOE")

These expenses include all costs incurred to operate wells and related facilities for both operated and non-operated properties. In addition to direct operating costs such as labor, repairs and maintenance, equipment rentals, materials and supplies, fuel and chemicals, LOE includes product marketing and transportation fees, insurance, ad valorem taxes and overhead charges provided for in operating agreements.

Total LOE, decreased by $1.1 million or 8% for the year ended December 31, 2016 relative to the comparable period in 2015. The decrease was due to our continued focus on reducing operating costs, economies of scale on our operated Eagle Ford property, and a decrease in the cost of oil field services in general.

Severance taxes

Severance taxes for the year ended December, 2016 decreased by $0.4 million or 15% relative to the comparable period in 2015, primarily due to the decline in oil and natural gas prices. As a percentage of revenues from oil, natural gas, and natural gas liquids, severance taxes remained relative flat and increased by only 1% due to the mix of production and revenues.

Rig idle and contract termination expense

We incurred rig idle and termination expenses of $5.1 million during the year ended December 31, 2016. In late January 2016, we suspended drilling and temporarily idled our contracted drilling rig. Our rig contractor agreed to a reduced daily rate of approximately $20,000 per day while the rig was idled. We subsequently entered into an agreement with the rig contractor to terminate our contract. Per the terms of the agreement, a termination fee for the remaining commitment on the contract was due and the termination fees were retroactively applied back to January 2016, when we suspended our daily drilling and temporarily idled our contracted drilling rig. In connection with the termination, we issued a three-year amortizing promissory note with an original principal amount of $5.1 million, which was equivalent to the unpaid idle charges and the termination fee.

Impairment

As a result of large commodity price declines and in spite of our operating achievements, we recognized $24.3 million noncash asset impairments in 2016 that have negatively impacted our results of operations and equity. The impairments recorded in 2016 consisted of $3.9 million to unproved properties, $2.9 million to proved properties and $17.5 million to goodwill.

Depreciation, depletion and amortization ("DD&A")

DD&A decreased for the year ended December 31, 2016 by $5.3 million, or 17% relative to the comparable period in 2015, due to lower production volumes and reduced net book value in the 2016 period as a result of the significant impairments recognized at the end of 2015. The reserve decreases that lead to the impairments were primarily attributable to lower average o il and natural gas prices in 2016.

General and administrative expense ("G&A")

These expenses consist primarily of employee remuneration, professional and consulting fees and other overhead expenses. G&A decreased by $0.3 million for the year ended December 31, 2016 relative to the comparable period in 2015. The decrease was primarily due to salary and benefits reductions taken during 2016.

Stock-based compensation

Stock-based compensation includes the expense associated with the 2016 grants of restricted stock units ("RSUs") to employees and non-employee directors. For the year ended December 31, 2016 we recognized expense of $3.3 million related to the RSU grants. The comparable prior period had no stock-based compensation expense since there were not any previously granted RSUs or other equity based compensation granted.

Transaction costs

Transaction costs consist primarily of professional and consulting fees associated with the Lynden Arrangement completed on May 18, 2016 and the Bold Contribution Agreement entered on November 7, 2016.

Interest expense, net

Interest expense includes commitment fees, amortization of deferred financing costs, and interest on outstanding indebtedness. Interest expense for the year ended December 31, 2016 was $1.3 million compared to $0.7 million for the comparable period in 2015. The $0.6 million increase in interest expense was due to higher amortization of deferred financing costs and increased fees due to a larger credit facility.

(Loss) gain on derivative contract, net

For the ended December 31, 2016, we recorded a net loss on derivative contracts of $6.6 million, consisting of net realized gains on settlements of $3.2 million and unrealized mark-to-market losses of $9.8 million. For the ended December 31, 2015, we recorded a net gain on derivative contracts of $6.4 million, consisting of net realized gains on settlements of $6.3 million and unrealized mark-to-market gains of $0.1 million. The primary reason for the current period loss as compared to the prior year gain is due to in improved commodity price environment in the latter part of 2016.

Income tax expense (benefit)

For the year ended December 31, 2016, we recorded $0.5 million of income tax expense related to Lynden. Our corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns. Taxable income of Earthstone, excluding the Lynden subsidiaries cannot be offset by tax attributes, including net operating losses of the Lynden subsidiaries, nor can taxable income of the Lynden subsidiaries be offset by tax attributes of Earthstone, excluding the Lynden subsidiaries. Excluding the Lynden subsidiaries, we have recorded significant income tax benefits in 2016 and 2015 resulting from property impairments which has resulted in a deferred tax asset. Because the future realization of this deferred tax asset could not be assured, we recorded a valuation allowance against our deferred tax asset of $12.2 million and $23.8 million in years ended December 31, 2016 and 2015, respectively.

Year ended December 31, 2015 compared to the year ended December 31, 2014

	Years Ended December 31, 2015	2014	Change
Sales volumes:			
Oil (MBbl)	904	403	124%
Natural gas (MMcf)	2,143	2,132	1%
Natural gas liquids (MBbl)	176	124	42%
Barrels of oil equivalent (MBOE)	1,437	882	63%
Average prices realized: (1)			
Oil (per Bbl)	$ 44.09	$ 86.29	-49%
Natural gas (per Mcf)	$ 2.55	$ 4.39	-42%
Natural gas liquids (per Bbl)	$ 12.29	$ 28.29	-57%
(In thousands)			
Oil revenues	$ 39,849	$ 34,734	15%
Natural gas revenues	$ 5,457	$ 9,367	-42%
Natural gas liquids revenues	$ 2,158	$ 3,510	-39%
Lease operating expense	$ 14,550	$ 9,422	54%
Severance taxes	$ 2,582	$ 2,002	29%
Impairment expense	$ 138,086	$ 19,359	613%
Depreciation, depletion and amortization	$ 31,228	$ 18,414	70%
General and administrative expense	$ 9,711	$ 6,830	42%
Transaction costs	$ 589	$ 1,034	-43%
Interest expense, net	$ 722	$ 597	21%
Gain on derivative contracts, net	$ (6,431)	$ (4,392)	46%
Income tax (benefit) expense	$ (26,442)	$ 22,105	-220%

(1) Prices presented exclude any effects of oil and natural gas derivatives.

Oil revenues

For the year ended December 31, 2015, oil revenues increased by $5.1 million or 15% relative to the comparable period in 2014. Of the increase, $22.1 million was attributable to increased volume, which was offset by $17.0 million attributable to a decrease in our realized price. The volume of oil we produced and sold increased by 501 MBbls; 317 MBbls were provided by our operated Eagle Ford property as a result of additional production from new wells drilled and completed during 2015 as well as the additional interests we acquired in late 2014 pursuant to the Flatonia Contribution Agreement; 212 MBbls of the total increase were provided by the legacy Earthstone assets. These significant increases were partially offset by production declines at our non-operated Eagle Ford property and variability in sales volumes in our conventional properties in Texas. Our average realized price per Bbl decreased from $86.29 for the year ended December 31, 2014 to $44.09 or 49% for the year ended December 31, 2015.

Natural gas revenues

For the year ended December 31, 2015, natural gas revenues decreased by $3.9 million or 42% relative to the comparable period in 2014. Substantially all of the $3.9 million decrease was attributable to the decrease in our realized price. The total volume of natural gas produced and sold remained relatively consistent and increased by only 11 MMcf in total. At the property level however, on our operated Eagle Ford property the volume of natural gas produced and sold increased by 96 MMcf as a result of additional production from new wells drilled and completed during 2015 as well as the additional interests we acquired in late 2014 pursuant to the Flatonia Contribution Agreement; the legacy Earthstone assets increased our volumes by 271 MMcf. These increases were offset by the loss of 169 MMcf from the Louisiana properties that were sold in April 2015 and production declines of 130 MMcf on our East Texas property. The remaining 57 MMcf decrease in volumes was due to decreased production in our conventional properties located in Oklahoma and South Texas. Our average realized price per Mcf decreased from $4.39 for the year ended December 31, 2014 to $2.55 or 42% for the year ended December 31, 2015.

Natural gas liquids revenues

For the year ended December 31, 2015, natural gas liquids revenues decreased by $1.4 million or 39% relative to the comparable period in 2014. Of the decrease, $2.0 million was attributable to a decrease in our realized price which was offset by a $0.6 million increase due to volume. The volume of natural gas liquids sales produced and sold increased by 52 MBbls; 30 MBbls of the total were provided by our operated Eagle Ford property as a result of additional production from new wells as well as the additional interests we acquired in late 2014 pursuant to the Flatonia Contribution Agreement and 31 MBbls of the total were provided by the legacy Earthstone assets; these increases were partially offset by production declines of 9 MBbls from our non-operated Eagle Ford property. Average realized price per Bbl decreased from $28.29 for the year ended December 31, 2014 to $12.29 or 57% for the year ended December 31, 2015.

Lease operating expense

Total LOE increased by $5.1 million or 54% for the year ended December 31, 2015 relative to the comparable period in 2014, which was due to the addition of the legacy Earthstone assets, costs on the new wells that we drilled and completed during 2015 in our operated Eagle Ford property as well as having a larger share of the gross costs in our Eagle Ford property due to the additional interests we acquired in late 2014 pursuant to the Flatonia Contribution Agreement.

Severance taxes

Severance taxes increased by $0.6 million or 29% for the year ended December 31, 2015 relative to the comparable period in 2014 primarily due to the additional production from new wells drilled and completed during 2015 in our operated Eagle Ford property as well as the additional interests we acquired in late 2014 pursuant to the Flatonia Contribution Agreement in that same property and the addition of the legacy Earthstone assets. As a percentage of revenues from oil, natural gas, and natural gas liquids, severance taxes increased from 4.20% to 5.44%, primarily due to a shift in our sales; for the year ended December 31, 2015, approximately 84% of our oil, natural gas and natural gas liquids revenue came from oil versus approximately 73% in same period during 2014. These oil revenues are taxed at the full rate whereas a large portion of our natural gas and natural gas liquids sales qualify for partial or full severance tax exemptions. Additionally, in late 2014, as result of the Exchange we added significant oil production from legacy Earthstone assets located in North Dakota and Montana; these states have higher severance tax rates than Texas where our operated Eagle Ford wells are located.

Impairment expense

As a result of large commodity price declines and in spite of our operating achievements, we recognized $138.1 million of noncash asset impairments in 2015 that have negatively impacted our results of operations and equity. The 2015 impairments consisted of $42.6 million on unproved properties, $94.0 million on proved properties and $1.5 million of goodwill. The impaired unproved properties consisted mainly of acreage throughout Milam and Grayson Counties in Texas as well as our Eagle Ford property in Fayette and Gonzales Counties in Texas. The impairment on proved properties resulted from capitalized costs in excess of the fair market value for our Eagle Ford properties in Fayette and Gonzales Counties in Texas as well as our non-operated Eagle Ford property in La Salle County, Texas. We also had impairments on the legacy Earthstone assets in Montana, Wyoming, North Dakota and south Texas.

During the year ended December 31, 2014, we incurred property impairment charges of $19.4 million, which consisted of $2.5 million on unproved properties and $16.9 million on proved properties. The impaired unproved properties consisted of acreage throughout Milam County, Texas. The impairment on proved properties primarily resulted from capitalized costs in excess of the fair market value for our non-operated Eagle Ford property and our Grayson County, Texas property.

Depreciation, depletion and amortization

Depreciation, depletion and amortization (“DD&A”) increased in the year ended December 31, 2015 by $12.8 million, or 70% compared to 2014, due to property additions related primarily to drilling and completion expenditures and increased production during the year ended December 31, 2015, as compared to the same period in 2014. On a unit-of-production basis, DD&A increased by only 4% despite significant capital additions to $21.73 per BOE during 2015 from $20.88 per BOE during 2014.

General and administrative expenses

G&A expenses increased by $2.9 million or 42% from $6.8 million to $9.7 million for the year ended December 31, 2015 relative to the comparable period in 2014. The increase was due to increased personnel costs and reporting requirements resulting from the Exchange completed in late 2014 and the growth of the Company. Also contributing to the increase are costs incurred, which must be expensed under GAAP, related to finding and completing property and corporate acquisitions.

Transaction costs

Transaction costs of $0.4 million for the year ended December 31, 2015 consist primarily of professional and consulting fees associated with the previously announced Lynden Arrangement in December 16, 2015.

Interest expense, net

Interest expense includes commitment fees, amortization of deferred financing costs, and interest on outstanding indebtedness. Interest expense increased from $0.6 million for the year ended December 31, 2014 to $0.8 million for the year ended December 31, 2015. The $0.2 million increase in interest expense was due to higher amortization of deferred financing costs and increased fees due to a larger credit facility.

Gain on derivative contracts, net

During the year ended December 31, 2015, we recorded a net gain on derivative contracts of $6.4 million, consisting of net realized gains on settlements of $6.3 million and unrealized mark-to-market gains of $0.1 million. During the year ended December 31, 2014, we recorded a net gain on derivative contracts of $4.4 million, consisting of net realized gains on settlements of $0.8 million and unrealized mark-to-market gains of $3.6 million.

Income tax (benefit) expense

During the year ended December 31, 2015, we recorded a net income tax benefit of $26.4 million as a result of our pre-tax net loss. Our effective tax rate for the year ended December 31, 2015, was approximately 18.5% which was less than the U.S. federal statutory tax rate primarily due to the addition of a valuation allowance in 2015. The impairments recorded during 2015 reduced the book value of our properties below our tax basis requiring us to record a net deferred tax asset. Because the future realization of this deferred tax asset cannot be assured, we recorded a valuation allowance against our deferred tax asset.

As a result of the Exchange, all historical financial information contained in this report is that of OVR and its subsidiaries. OVR, is a partnership for federal income tax purposes and is not subject to federal income taxes or state or local income taxes that follow the federal treatment, and therefore OVR does not pay or accrue for such taxes. Pursuant to the Exchange, Oak Valley has become a subsidiary of Earthstone, a taxable entity; as such we recorded tax expense during the year ended December 31, 2014.

Liquidity and Capital Resources

We expect to finance future acquisition, development and exploration activities through available working capital, cash flows from operating activities, possible borrowings under our credit facility, sale of non-strategic assets, various means of corporate and project financing, and assuming we can access the capital markets, the issuance of additional equity securities. In addition, we may continue to partially finance our drilling activities through the sale of participating rights to industry partners or financial institutions, and we could structure such arrangements on a promoted basis, whereby we may earn working interests in reserves and production greater than our proportionate capital costs.

Bold Contribution Agreement

The anticipated closing of the Bold Contribution Agreement will require additional capital to develop the undeveloped drilling locations. We expect to close the Bold Contribution Agreement in the second quarter of 2017 and deploy one drilling rig and may attempt to accelerate drilling in the fourth quarter of 2017 by deploying a second drilling rig. The incremental capital requirements related to Bold Contribution Agreement post-closing activities are expected to be funded by the combined cash flows from operating activities and borrowings from the combined borrowing bases, as well as potential access to capital markets. For additional information, see *Executive Overview, Strategy and 2017 Outlook* above.

Common Stock Offering

In June 2016, we completed a public offering of 4,753,770 shares of common stock (including 253,770 shares purchased pursuant to the underwriters' overallotment option), at an issue price of $10.50 per share. We received net proceeds from this offering of $47.1 million, after deducting underwriters' fees and offering expenses of $2.7 million. We used $37.8 million of the net proceeds from the offering to partially repay outstanding indebtedness under our revolving credit facility; the majority of which was incurred in connection with the Lynden Arrangement.

Senior Secured Revolving Credit Facility and Promissory Note

In December 2014, we entered into a credit agreement providing for a $500.0 million four-year senior secured revolving credit facility (the “Credit Agreement”) with BOKF, NA dba Bank of Texas (“Bank of Texas”), as agent and lead arranger, Wells Fargo Bank, National Association (“Wells Fargo”), as syndication agent, and the Lenders signatory thereto (collectively with Bank of Texas and Wells Fargo, the “Lender”).

The current borrowing base of our Credit Agreement $80.0 million and is subject to redetermination during May and November of each year. The amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate (“LIBOR”) plus the applicable utilization margin of 2.25% to 3.25% or (b) the base rate (which is equal to the greater of the prime rate, the Federal Funds effective rate plus 0.50%, and 1-month LIBOR plus 1.00%) plus applicable margin of 1.25% to 2.25%. Principal amounts outstanding under the Credit Agreement are due and payable in full at maturity on December 19, 2018. 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 fee, which is due quarterly, is 0.50% per year on the unused portion of the borrowing base. We are also required to pay customary letter of credit fees. At December 31, 2016, we had approximately $69.8 million of borrowing capacity under our Credit Agreement. Our Credit Agreement contains customary covenants and we were in compliance with them as of December 31, 2016.

In connection with the termination of a drilling rig contract, we entered into a $5.1 million three-year promissory, which has an interest rate for the first year of 8%, 10% for the second year and 12% for the third year and does not contain a prepayment penalty. The initial principal balance on the note was equal to the unpaid idle fees that we previously included in accounts payable and the remaining termination amount of the contract. The idle charges and the termination amount on the rig contract are reflected in operating costs and expenses during the year ended December 31, 2016. At December 31, 2016, the balance on the note was $4.3 million of which $1.6 million is included in current liabilities.

Cash Flows from Operating Activities

Substantially all of our cash flows provided by or used in operating activities are derived from and used in the production of our oil, natural gas, and natural gas liquids reserves. We use any excess cash flows to fund our drilling and completion operations and acquisitions of additional mineral leases. Variations in operating cash flows may impact our level of capital expenditures.

Cash flows provided by operating activities for the year ended December 31, 2016 were $1.7 million compared to cash flows used in operating activities of $10.4 million for the year ended December 31, 2015. The increase in operating cash flows from the prior year period was primarily due to changes in our working capital. We believe we have sufficient liquidity and capital resources to execute our business plan over the next 12 months and for the foreseeable future.

Cash Flows from Investing Activities

Cash applied to oil and natural gas properties for the years ended December 31, 2016 and 2015 were $59.8 million and $61.1 million, respectively. Cash applied to oil and natural gas properties in the year ended December 31, 2016 of $59.8 million, included $31.4 million related to the May 2016 acquisition of Lynden Energy Corp. and $28.4 million of additions to our existing oil and gas properties, of which $18.4 million related to our operated Eagle Ford properties, $6.1 million related to our non-operated Midland Basin, and $3.2 million related to our non-operated Bakken properties.

Cash Flows from Financing Activities

Cash flows provided by financing activities for the year ended December 31, 2016 were $45.1 million which consisted of $47.1 million provided through the public offering completed in June 2016, offset by $1.2 million in net repayment of borrowings on our credit facility, $0.7 million in repayments on a promissory note to a drilling contractor, and $0.1 million related to deferred financing costs. There were no cash flows provided by financing activities in the prior year period.

Obligations and Commitments

We had the following contractual obligations and commitments as of December 31, 2016:

(In thousands)	2017	2018	2019	2020	2021	Thereafter
Debt	$ 1,715	$ 11,746	$ 947	$ —	$ —	$ —
Derivative liabilities	4,595	1,575	—	—	—	—
Asset retirement obligations	2,737	476	18	115	—	2,667
Gas contracts*	1,643	1,643	1,643	1,647	680	—
Office leases	738	661	627	—	—	—
Total	$ 11,428	$ 16,101	$ 3,235	$ 1,762	$ 680	$ 2,667

* We have a non-cancelable fixed cost agreement of $1.6 million per year through 2021 to reserve pipeline capacity of 10,000 MMBtu per day for gathering and processing related to certain Eagle Ford assets in south Texas through 2021.

Off-Balance Sheet Arrangements

In conjunction with our office lease located in The Woodlands, Texas, we had established letters of credit in the amount of $0.2 million and $0.3 million at December 31, 2016 and December 31, 2015, respectively.

Other than normal operating leases for office space and the letter of credit noted above, we do not have any off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other risks. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Oil and Natural Gas Properties

We use the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire oil and natural gas properties, drill successful exploratory wells, drill and equip development wells, and install production facilities are capitalized. Exploration costs, including unsuccessful exploratory wells, geological and geophysical are charged to operations as incurred. Depreciation, depletion and amortization of the leasehold and development costs that are capitalized for proved oil and natural gas properties are computed using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers. Oil and natural gas properties are periodically assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group, but at least annually. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. All of our properties are located within the continental United States.

Oil and Natural Gas Reserve Quantities

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, and asset retirement obligations. Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board ("FASB"). The accuracy of our reserve estimates is a function of:

- The quality and quantity of available data;
- The interpretation of that data;

- The accuracy of various mandated economic assumptions; and
- The judgments of the persons preparing the estimates.

Our proved reserves information included in this report is based on estimates prepared by our independent petroleum engineers, CG&A. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of December 31, 2016. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates, impairment calculations, and asset retirement obligations in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization

Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Natural Gas Properties

We review the value of our oil and natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments of producing properties are determined by comparing the pretax future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds undiscounted future cash flows, the cost of the property is written down to “fair value,” which is determined based on expected future cash flows using discount rates commensurate with the risks involved, using prices and costs consistent with those used for internal decision making. Different pricing assumptions or discount rates could result in a different calculated impairment. We provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred.

Asset Retirement Obligation

Our asset retirement obligations (“AROs”) consist primarily of estimated future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the field.

Derivative Instruments and Hedging Activity

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are utilized to economically hedge the Company’s exposure to price fluctuations and reduce the variability in the Company’s cash flows associated with anticipated sales of future oil and natural gas production. The Company follows Financial Accounting Standards Board (“FASB”) ASC Topic 815, *Derivatives and Hedging,* to account for its derivative financial instruments. The Company does not enter into derivative contracts for speculative trading purposes. It is the Company’s policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive. The Company did not post collateral under any of these contracts.

The Company’s crude oil and natural gas derivative positions consist of swaps. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in “*Gain (loss) on* *derivative contracts, net*" on the Consolidated Statements of Operations. All derivative contracts are recorded at fair market va lue and are included in the Consolidated Balance Sheets as assets or liabilities.

Income Taxes and Uncertain Tax Positions

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

We will consider a tax position settled if the taxing authority has completed its examination, we do not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. We use the benefit recognition model which contains a two-step approach, a more likely than not recognition criteria and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, then we will not record the tax benefit. The amount of interest expense that we recognize related to uncertain tax positions is computed by applying the applicable statutory rate of interest to the difference between the tax position recognized and the amount previously taken or expected to be taken in a tax return.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition

We predominantly derive our revenue from the sale of produced oil, natural gas, and natural gas liquids. Revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has been transferred, and collectability is probable. We receive payment from one to three months after delivery. At the end of each quarter, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, however, differences have been insignificant.

Accounting for Business Combinations

Our business has grown substantially through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations to date using the purchase method.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair value including the recognition of acquisition-related costs that are separate from the acquired net assets. The purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, and comparison to transactions for similar assets and liabilities, and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Goodwill

We account for goodwill in accordance with FASB ASC Topic 350. Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of the liabilities assumed in an acquisition. ASC 350 requires that goodwill be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in an impairment.

We conduct a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our goodwill such as, industry and market conditions, including commodity prices, costs factors, and other company specific events. If we conclude that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then we do not have to perform the two-step impairment test. If after assessing the totality of events or circumstances described, we determine that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the two-step goodwill test is performed. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If, after performing the two-step goodwill test, it is determined that the carrying value of goodwill is impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired

Recently Issued Accounting Standards

See *Note 2. Summary of Significant Accounting Policies* in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for discussion of recently issued and adopted accounting standards affecting us.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. We have established risk management processes to monitor and manage these market risks.

Commodity Price Risk, Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable. Therefore, we use derivative instruments to provide partial protection against declines in oil and natural gas prices and the adverse effect it could have on our financial condition and operations. The types of derivative instruments that we may choose to utilize include costless collars, swaps, and deferred put options. Our hedge objectives may change significantly as our operational profile changes and/or commodities prices change. Currently, we have hedged only a limited amount of our anticipated production beyond 2017 due to low commodity prices. As a consequence, our future performance is subject to increased commodity price risks, and our future cash flows from operations may be subject to further declines if low commodity prices persist. We do not enter into derivative contracts for speculative trading purposes.

The following is a summary of our open oil and natural gas derivative contracts as of December 31, 2016:

	Price Swaps		
Period	**Commodity**	**Volume (Bbls / MMBtu)**	**Weighted Average Price ($/Bbl / $/MMBtu)**
Q1 - Q4 2017	Crude Oil	600,000	$ 50.38
Q1 - Q4 2018	Crude Oil	270,000	$ 50.70
Q1 - Q4 2017	Natural Gas	1,740,000	$ 2.997
Q1 - Q4 2018	Natural Gas	600,000	$ 2.907

Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a liability position with a fair value of $6.2 million at December 31, 2016. Based on the published commodity futures price curves for the underlying commodity as of December 31, 2016, a 10% increase in per unit commodity prices would cause the total fair value of our commodity derivative financial instruments to decrease by approximately $5.0 million to a liability of $11.2 million. A 10% decrease in per unit commodity prices would cause the total fair value of our commodity derivative financial instruments to increase by approximately $5.2 million to a net liability of $1.0 million. There would also be a similar increase or decrease in *(Loss) gain on derivative contracts, net* in the Consolidated Statements of Operations

The following table presents average NYMEX prompt month future prices for crude oil and natural gas for the periods identified, as well as average sales prices we realized for our crude oil, natural gas and natural gas liquids production:

	Years Ended December 31,			
	2016		2015	
Average NYMEX prompt month future prices:				
Oil (per Bbl)	$	43.40	$	48.79
Natural gas (per Mcf)	$	2.55	$	2.63
Average prices realized:				
Oil (per Bbl)	$	39.13	$	44.09
Natural gas (per Mcf)	$	2.32	$	2.55
Natural gas liquids (per Bbl)	$	12.74	$	12.29

Interest Rate Sensitivity

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and the prime rate based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At December 31, 2016, the principal amount of our long-term debt with our credit facility was $10.0 million and bears interest at rates further described in *Note 11. Long-Term Debt*. Fluctuations in interest rates will cause our annual interest costs to fluctuate. At December 31, 2016, the interest rate on borrowings under our revolving credit facility was 2.867% per year. If these borrowings at December 31, 2016 were to remain constant, a 10% change in interest rates would impact our cash flow by approximately $29,000 per year.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2016, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time and interest rates and commodity prices at the time.

Item 8. Financial Statements and Supplementary Data

See *Index to Consolidated Financial Statements and Supplementary Information* on Page F-1.

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

None.

Item 9A. Controls and Procedures

Internal Control Over Financial Reporting

Evaluation of Disclosure Controls and Procedures

(a) Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Principal Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Rules 13a-15(b) and 15d-15(b) under the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Principal Accounting Officer, of the effectiveness of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below under paragraph (b) within Management’s Annual Report on Internal Control over Financial Reporting, our Chief Executive Officer and Principal Accounting Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were effective to provide re asonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Principle Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

The audit report of our independent registered public accounting firm, which is included in this Annual Report on Form 10-K, expressed an unqualified opinion on our consolidated financial statements.

(b) Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management; and
- 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.

While "reasonable assurance" is a high level of assurance, it does not mean absolute assurance. Because of its inherent limitations, internal control over financial reporting may not prevent or detect every misstatement and instance of fraud. Controls are susceptible to manipulation, especially in instances of fraud caused by collusion of two or more people. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our Chief Executive Officer and Principal Accounting Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2016. In making this evaluation, management used the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on the results of our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2016.

Our independent registered public accounting firm that audited our consolidated financial statements, has also issued its own audit report on the effectiveness of our internal control over financial reporting as of December 31, 2016, which is included herein.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting during the quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTIN G FIRM

Board of Directors and Shareholders
Earthstone Energy, Inc.

We have audited the internal control over financial reporting of Earthstone Energy, Inc., a Delaware corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's annual report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2016, and our report dated March 15, 2017 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2017

Item 9B. Other Information

None.

Item 10. Directors, Executives Officers and Corporate Governance

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

Board of Directors of the Company

The following table sets forth certain information as of March 1, 2017, regarding our directors:

Name	Director Since	Age	Position	Expiration of Term
Frank A. Lodzinski	December 2014	67	Chairman of the Board, President and Chief Executive Officer	2019
Jay F. Joliat	December 2014	60	Director	2018
Phil D. Kramer	October 2016	60	Director	2018
Ray Singleton	July 1989	66	Director, Executive Vice President Northern Region	2019
Douglas E. Swanson, Jr.	December 2014	45	Director	2017
Brad A. Thielemann	December 2014	40	Director	2017
Zachary G. Urban	December 2014	39	Director	2017
Robert L. Zorich	December 2014	67	Director	2018

Frank A. Lodzinski has served as our Chairman, President and Chief Executive Officer since December 2014. Previously, he served as President and Chief Executive Officer of OVR from its formation in December 2012 until the closing of its strategic combination with us in December 2014. Prior to his service with OVR, Mr. Lodzinski was Chairman, President and Chief Executive Officer of GeoResources, Inc. from April 2007 until its merger with Halcón Resources Corporation (“Halcón”) in August 2012 and from September 2012 until December 2012 he conducted pre-formation activities for OVR. He has over 43 years of oil and gas industry experience. In 1984, he formed Energy Resource Associates, Inc., which acquired management and controlling interests in oil and gas limited partnerships, joint ventures and producing properties. Certain partnerships were exchanged for common shares of Hampton Resources Corporation in 1992, which Mr. Lodzinski joined as a director and President. Hampton was sold in 1995 to Bellwether Exploration Company. In 1996, he formed Cliffwood Oil & Gas Corp. and in 1997, Cliffwood shareholders acquired a controlling interest in Texoil, Inc., where Mr. Lodzinski served as a director, Chief Executive Officer and President. In 2001, Mr. Lodzinski was appointed Chief Executive Officer and President of AROC, Inc., to direct the restructuring and ultimate liquidation of that company. In 2003, AROC completed a monetization of oil and gas assets with an institutional investor and began a plan of liquidation in 2004. In 2004, Mr. Lodzinski formed Southern Bay Energy, LLC, the general partner of Southern Bay Oil & Gas, L.P., which acquired the residual assets of AROC, Inc., and he served as President of Southern Bay Energy, LLC upon its formation. The Southern Bay entities were merged into GeoResources in April 2007. Mr. Lodzinski has served as a director of Yuma Energy, Inc. since September 2014. He also served as a member of the Audit Committee from September 2014 until October 2016. In October 2016, he was appointed a member of the Compensation Committee. He holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

The Board, in reviewing and assessing the contributions of Mr. Lodzinski to the Board, determined that his leadership and intimate knowledge of the oil and gas industry, our structure, and our operations, provide the Board with company specific experience and expertise.

Jay F. Joliat has served as a director since December 2014. For more than the past 30 years, Mr. Joliat has been an independent investor and developer in commercial, industrial and garden style apartment real estate, land development and residential home building, restaurant ownership and management, and has had extensive experience in placement of venture private equity in generic pharmaceuticals, medical devices/procedures and oil and gas. Mr. Joliat has been the Chief Executive Officer of Fieldstone Village Development, LLC since January 2011. He has been the Chief Executive Officer of Joliat & Company, Inc. since October 1988. He has been the Chief Executive Officer and Chief Investment Officer of Joliat Ventures, LLC and Chief Executive Officer of Joliat Enterprises, LLC since January 1988. Since January 1981, Mr. Joliat has served as Chief Executive Officer and Treasurer of Sign of the Beefcarver Restaurants, Inc. He formed and managed his own investment management company early in his career and was formerly employed by E.F. Hutton, Dean Witter Reynolds and LPL Financial. He holds a Bachelor of Arts Degree in Management and Finance from Oakland University (1982) and was awarded a Certified Investment Management Analyst certificate in 1983 after completion of the IMCA program at the Wharton School of the University of Pennsylvania. From 1996 through 2003, Mr. Joliat served on the Board of Directors of Caraco Pharmaceutical Laboratories Ltd., and served in various capacities on its audit, executive and compensation committees. From 2007 through August 2012, Mr. Joliat served on the Board of Dire ctors of GeoResources, Inc., and served in various capacities on the audit, nominating and compensation committees until its merger with Halcón in August 2012.

The Board, in reviewing and assessing the contributions of Mr. Joliat to the Board, determined that his business experience in management and investments, as well as previously serving on the boards of directors of SEC reporting companies, brings a unique perspective as an outside investor in oil and gas entities. His management skills, understanding of public and private capital markets, and financial acumen provide the Board with a valuable resource for planning corporate strategy.

Phil D. Kramer has served as a director since October 2016. Mr. Kramer has served as an Executive Vice President of Plains All American Pipeline, L.P. ("PAA"), an energy infrastructure and logistics company based in Houston, Texas, since November 2008. He also served as Chief Financial Officer of PAA from 1998 until 2008. He was a director and chairman of the audit committee of PetroLogistics GP, the general partner of PetroLogistics LP, from July 2012 until its sale in July 2014. Mr. Kramer graduated from the University of Oklahoma in 1978 with a degree in accounting and was previously a Certified Public Accountant. He is currently on the board of advisors of Price College of Business at the University of Oklahoma.

The Board, in reviewing and assessing the contributions of Mr. Kramer to the Board, determined that his overall business and management experience and detailed knowledge of both the mid-stream and up-stream segments of the oil & gas industry, as well as his experience and understanding of public capital markets provides the Board with valuable insight and advice. Further, his education and prior standing as a Certified Public Accountant provides the Board with additional expertise.

Ray Singleton is a petroleum engineer with over 37 years of experience in the oil and gas industry. He has been one of our directors since July 1989 and was our President and Chief Executive Officer from March 1993 until December 2014. Since December 2014, he has served as our Executive Vice President, Northern Region. Mr. Singleton joined us in 1988 as a Production Manager/Petroleum Engineer. From 1983 until 1988, he owned and operated an engineering consulting firm (Singleton & Associates) serving the needs of 40 small oil and gas clients. During this period, he was engaged by Earthstone on various projects in south Texas and the Rocky Mountain region. Mr. Singleton began his career with Amoco Production Company in 1973 as a production engineer in Texas. He was subsequently employed by the predecessor of Union Pacific Resources as a drilling, completion and production engineer from 1980 to 1983. His professional experience includes acquisition evaluation and economics, reserve engineering and drilling, completion and production engineering in both Texas and the Rocky Mountain region. In addition, he possesses over 21 years of executive experience and has an intimate knowledge of Earthstone's legacy Rocky Mountain and south Texas properties. Mr. Singleton received a B.S. degree in Petroleum Engineering from Texas A&M University in 1973, and received an MBA from Colorado State University's Executive MBA Program in 1992.

In determining Mr. Singleton's qualifications to serve on the Board, the Board considered, among other things, his experience and expertise in the oil and gas industry, including the operating, management or executive positions he has held with the Company and other oil and gas companies, and his extensive knowledge of the Company's business, all of which has proven to be beneficial to us.

Douglas E. Swanson, Jr. has served as a director since December 2014. He is a Managing Partner at EnCap Investments L.P. and serves on the firm's up-stream investment and management committees. Prior to joining EnCap in 1999, he was in the corporate lending division of Frost National Bank, specializing in energy-related service companies, and was a financial analyst in the corporate lending group of Southwest Bank of Texas. Mr. Swanson serves on the board of each of Eclipse Resources Corporation, Oasis Petroleum Inc. and several EnCap portfolio companies. Mr. Swanson is a member of the Independent Petroleum Association of America and the Texas Independent Producers and Royalty Owners Association. Mr. Swanson holds a B.A. in Economics and an M.B.A., both from the University of Texas at Austin.

The Board, in reviewing and assessing the contributions of Mr. Swanson to the Board, determined that his extensive experience in the oil and gas exploration and production industry, including serving on the boards of public and private oil and gas companies provide significant contributions to the Board. As a managing partner at EnCap, Mr. Swanson is uniquely positioned to provide the Board with insight and advice on a full range of strategic, financial and governance matters.

Brad A. Thielemann has served as a director since December 2014. He is a Managing Director at EnCap Investments L.P. Prior to joining EnCap in 2006, he worked in the Investor Relations and Strategic Planning Groups at Plains All American Pipeline, L.P. Prior to that, he was an Associate at EnCap from 2000 to 2003 and a Treasury Analyst at Dynegy. Mr. Thielemann holds an M.B.A. from Duke University and a B.A. in Business Administration from The University of Texas at Austin. He serves on the boards of several EnCap portfolio companies, is on the board of the Houston Producers' Forum and is a member of the Independent Petroleum Association of America.

The Board, in reviewing and assessing the contributions of Mr. Thielemann to the Board, determined that his extensive experience in the oil and gas industry, including serving on the boards of private oil and gas exploration and production companies provide significant contributions to the Board. As a managing director at EnCap, Mr. Thielemann is uniquely positioned to provide the Board with insight and advice on a full range of strategic, financial and governance matters.

Zachary G. Urban has served as a director since December 2014. Since January 2014, Mr. Urban has served as CEO at Vlasic Group, which is a private investment company with holdings in a wide variety of asset classes. Prior to being named CEO, Mr. Urban held the position of Managing Director of Investments at Vlasic Group from 2011 through 2013. At Vlasic Group, Mr. Urban has responsibility for a full spectrum of investment disciplines, including asset allocation, investment strategy, direct investments, manager selection, due diligence, and performance measurement. From 2001 to 2011, Mr. Urban worked at Donnelly Penman & Partners ("DP&P"), a regional investment bank. At DP&P, Mr. Urban specialized in merger and acquisition transactions, business valuations, financial advisory, due diligence services, and capital raising for middle market public and private clients. Prior to his time at DP&P, Mr. Urban also worked in the Corporate Value Consulting practice of PricewaterhouseCoopers LLP, where he focused on business valuation services, strategic consulting, and corporate finance consulting for public and private companies, including multinational and Fortune 500 clients. Mr. Urban holds the Chartered Financial Analyst (CFA) designation and graduated from the Honors College of Michigan State University with a B.A. degree in Finance with High Honor.

The Board, in reviewing and assessing the contributions of Mr. Urban to the Board, determined that his extensive investment experience across diverse industries as CEO of the Vlasic Group provide significant contributions to the Board. In addition, his prior experience as an investment banker will enable Mr. Urban to provide the Board with insight and advice on a full range of general business and financial matters.

Robert L. Zorich has served as a director since December 2014. Mr. Zorich is a Managing Partner and co-founder of EnCap Investments L.P. He serves on the firm's up-stream investment and management committees and has been actively involved in all aspects of the firm's management and growth since its inception in 1988. EnCap is a leading private equity firm focused on the up-stream and midstream sectors of the oil and gas industry in North America, having raised 19 institutional oil and gas investment funds, totaling in excess of $27 billion of capital. Over its history, the firm has created over 220 oil and gas companies and currently manages capital on behalf of more than 250 U.S. and international investors, including public and private pension funds, insurance companies, sovereign wealth funds, university endowments and foundations. Prior to the formation of EnCap, Mr. Zorich was a Senior Vice President in charge of the Houston office of Trust Company of the West, then a large, privately-held pension manager. Previously, Mr. Zorich co-founded MAZE Exploration, Inc., a private oil and gas company headquartered in Denver. For the first seven years of his career, Mr. Zorich was employed by Republic Bank as a Vice President and Division Manager in the energy group. Mr. Zorich serves on the boards of several EnCap portfolio companies. He is also a member of the Board of Directors of Eclipse Resources Corporation and previously served on the board of Oasis Petroleum Inc. and its predecessor entities from March 2007 until March 2012. In addition, he serves on the investment committee of EnCap Flatrock Midstream. Mr. Zorich's community involvement includes serving as a member of the Leadership Cabinet of Texas Children's Hospital, as well as serving on the boards of the Workfaith Connection and the Memorial Assistance Ministries Endowment. He is a member of the Independent Petroleum Association of America, the Houston Producers' Forum and Texas Independent Producers and Royalty Owners Association. Mr. Zorich holds a B.A. in Economics from the University of California at Santa Barbara and a Master's Degree in International Management (with distinction) from the American Graduate School of International Management in Phoenix, Arizona.

The Board, in reviewing and assessing the contributions of Mr. Zorich to the Board, determined that his significant experience with financing, forming, and guiding numerous oil and gas companies while serving as a co-founder and managing partner of EnCap provide significant contributions to the Board. His insights and relationships should prove valuable towards guiding corporate strategies and pursuing growth opportunities.

There are no arrangements or understandings between any of Messrs. Lodzinski, Singleton, Joliat, Kramer, Swanson, Thielemann, Urban and Zorich, or any other person pursuant to which such person was selected as a director. None of Messrs. Lodzinski, Singleton, Joliat, Kramer, Swanson, Thielemann, Urban and Zorich has any family relationship with any director or other executive officer of the Company or any person nominated or chosen by the Company to become a director or executive officer.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the Company's directors and certain executive officers, and persons who beneficially own more than ten percent of our common stock, to file initial reports of ownership and reports of changes in ownership of our common stock and our other equity securities with the SEC. As a practical matter, the Company assists its directors and officers by monitoring transactions and completing and filing Section 16 reports on their behalf. Based solely on a review of the copies of such forms in our possession and on written representations from reporting persons, we believe that during 2016 all of our named executive officers, directors and greater than ten percent holders filed the required reports on a timely basis under Section 16(a) of the Exchange Act.

Code of Business Conduct and Ethics

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

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

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

Board of Directors and Committees

General

On December 19, 2014, following the closing of the Exchange Agreement, and as required by the Exchange Agreement, the Company expanded the size of its Board from four to seven members. At closing of the Exchange Agreement, our directors, other than Ray Singleton, resigned from our Board and Frank A. Lodzinski, Jay F. Joliat, Douglas E. Swanson, Jr., Brad A. Thielemann, Zachary G. Urban, and Robert L. Zorich were appointed as directors to serve on the Board until their successors are duly elected and qualified. Also, our former officers resigned from their positions as of the closing of the Exchange Agreement. In October 2016, our Board expanded the size of the Board to eight members and appointed Phil D. Kramer as a Class III director.

Our Amended and Restated Certificate of Incorporation provides for the classification of the Board into three classes with staggered three-year terms. Messrs. Singleton and Lodzinski serve as Class I directors. Messrs. Swanson, Thielemann and Urban serve as Class II directors, and Messrs. Joliat, Kramer and Zorich serve as Class III directors.

We are committed to high quality corporate governance, which helps us compete more effectively, sustain our success and build long-term stockholder value. The Board reviews the Company's policies and business strategies, and advises and counsels the executive officers who manage the Company.

The full text of the charter of our Audit Committee and our Code of Ethics can be found at www.earthstoneenergy.com. Copies of these documents also may be obtained from our Corporate Secretary.

Governance is a continuing focus at the Company, starting with the Board and extending to management and all employees. The Company is governed by a Board of Directors and committees of the Board that meet throughout the year. Directors discharge their responsibilities at Board and committee meetings and also through telephone contact and other communications with management.

Director Attendance

During 2016, our Board held three meetings and all of our directors at the time attended all of the meetings either in person or telephonically. In addition, the Board acts from time to time by unanimous written consent in lieu of holding a meeting. During 2016, the Board effected 18 actions by unanimous written consent.

We do not have a formal policy regarding our Board members' attendance at the annual meeting of stockholders. In 2016, Mr. Lodzinski and members of management attended our annual meeting of stockholders along with certain members of our Board that dialed in telephonically.

Formerly a Controlled Company

In 2015, our Board determined that we were a “controlled company” as defined under the corporate governance rules of the NYSE MKT since more than 50% of our issued and outstanding common stock was then held by OVR. As a “controlled company,” we were exempt from certain rules otherwise applicable to companies whose securities are listed on the NYSE MKT, including: (a) the requirement that the Company have a majority of independent directors; (b) the requirement that nominations to the Board be either selected or recommended by a nominating committee consisting solely of independent directors; and (c) the requirement that the Company’s officers’ compensation be either determined or recommended by a compensation committee consisting solely of independent directors. As a result of our equity offering in June 2016, our Board determined that we ceased to be a “controlled company” as defined under the corporate governance rules of the NYSE MKT. Accordingly, the Company will need to have a majority of the members of its Board be “independent” as defined under the corporate governance rules of the NYSE MKT within one year of no longer being a “controlled company.”

Board Leadership

Our Board is responsible for the control and direction of the Company. The Board represents the Company’s stockholders and its primary purpose is to build long-term stockholder value. Mr. Lodzinski serves as Chairman of the Board, President and Chief Executive Officer of the Company. The Board believes that Mr. Lodzinski is best situated to serve as Chairman because he is the director most familiar with the Company’s business and industry and is also the person most capable of effectively identifying strategic priorities and leading the discussion and execution of corporate strategy. In this combined role, Mr. Lodzinski is able to foster clear accountability and effective decision making. The Board believes that the combined role of Chairman and Chief Executive Officer strengthens the communication between the Board and management and provides a clear roadmap for stockholder communications. Further, as the individual with primary responsibility for managing day-to-day operations, Mr. Lodzinski is best positioned to chair regular Board meetings and ensure that key business issues and risks are brought to the attention of our Board and the Audit Committee. We therefore believe that the creation of a lead independent director position is not necessary at this time.

Stockholder-Recommended Director Candidates

The Board is responsible for identifying individuals qualified to become Board members and nominees for directorship are selected by the Board. The Board takes into account many factors, including general understanding of marketing, finance and other disciplines relevant to the success of a publicly traded company in today’s business environment; understanding of the Company’s business on a technical level; and educational and professional background. The Board evaluates each individual in the context of the Board as a whole, with the objective of recommending a group that can best support the success of the business and, based on its diversity of experience, represent stockholder interests through the exercise of sound judgment.

Although the Board is willing to consider candidates recommended by our stockholders, it has not adopted a formal policy with regard to the consideration of any director candidates recommended by our stockholders. The Board believes that a formal policy is not necessary or appropriate because the current Board already has a diversity of business background and industry experience. Additionally, the Board does not have a formal diversity policy in place for the director nomination process, but instead considers diversity of a candidate’s viewpoints, professional experience, education and skill set as a factor in the consideration and assessment of a candidate as set forth above.

In accordance with our Bylaws, stockholders wishing to recommend a director candidate to serve on the Board may do so by providing advance written notice to the Board, which identifies the candidate and includes the information described below. The notice should be sent to the following address: Earthstone Energy, Inc., Attention: Corporate Secretary, 1400 Woodloch Forest Drive, Suite 300, The Woodlands, Texas 77380. The mailing envelope should contain a clear notation indicating that the enclosed letter is a “Director Nomination Recommendation.”

The notice must contain the following information as to each proposed nominee:

- name, age, business address and residence address of the nominee;
- principal occupation or employment of the nominee;
- class or series and number of shares of our capital stock that are owned beneficially or of record by the nominee; and
- any other information relating to the nominee that would require disclosure in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of directors pursuant to Section 14 of the Exchange Act.

The notice must also contain the following information as to the stockholder giving the notice:

- name and record address of such stockholder;
- class or series and number of shares of our capital stock that are owned beneficially or of record by such stockholder;
- all other ownership interests of such stockholder relating to us, including derivatives, hedged positions, synthetic and temporary ownership techniques, swaps, securities, loans, timed purchases and other economic and voting interests;
- a description of all arrangements or understandings between such stockholder and each proposed nominee and any other person or persons (including their names) pursuant to which the nomination(s) are to be made by such stockholder;
- a representation that such stockholder intends to appear in person or by proxy at the meeting to nominate the persons named in such stockholder's notice; and
- any other information relating to such stockholder that would require disclosure in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of directors pursuant to Section 14 of the Exchange Act.

In addition to the foregoing requirements, such notice must be accompanied by a written consent of each proposed nominee to being named as a nominee and to serve as a director if elected. Each proposed nominee will be required to complete a questionnaire, in a form to be provided by us, to be submitted with the stockholder's notice. We may also require any proposed nominee to furnish such other information as we may reasonably require in order to determine the eligibility of such proposed nominee to serve as an independent director or that could be material to a reasonable stockholder's understanding of the independence, or lack thereof, of such nominee.

Board Committees

To assist it in carrying out its duties, the Board has delegated certain authority to an Audit Committee as its functions are described below. Each member of the Audit Committee has been determined by the Board to be "independent" for purposes of the listing standards of NYSE MKT and the rules of the SEC, including the heightened "independence" standard required for members of the Audit Committee.

Audit Committee

The Audit Committee provides oversight of the Company's accounting policies, internal controls, financial reporting practices and legal and regulatory compliance. Among other things, the Audit Committee appoints our independent auditor and evaluates its independence and performance; maintains a line of communication between the Board, our management and the independent auditor; and oversees compliance with the Company's policies for conducting business, including ethical business standards.

The members of our Audit Committee during 2016 were Jay F. Joliat (Chairperson) and Zachary G. Urban. On January 6, 2016, Mr. Thielemann was appointed to the Audit Committee. On October 12, 2016, Mr. Kramer was appointed to the Audit Committee and Mr. Thielemann resigned from the Audit Committee. During 2016, the Audit Committee held four meetings. The Board has determined that Mr. Joliat is an "audit committee financial expert" as that term is defined in the listing standards of NYSE MKT and the applicable rules of the SEC.

Compensation Committee

Our Board does not have a separate compensation committee. After the Company ceased being a "controlled company" in June 2016, all material compensation decisions related to the named executive officers of the Company will be made by the independent directors serving on the Board.

Nominating Committee

Our Board does not have a separate nominating committee. After the Company ceased being a "controlled company" in June 2016, all decisions relating to the nomination of directors to the Board will be made by the independent directors serving on the Board.

Compensation Committee Interlocks and Insider Participation

Our Board does not have a separate compensation committee. None of our executive officers serve or have served on the compensation committee of any entity that has one or more of its executive officers serving as a member of our Board. Our President and Chief Executive Officer, Frank A. Lodzinski has participated in discussions with our Board regarding the compensation of our executive officers; however, he is not present during discussions regarding his compensation.

Item 11. Executive Compensation

Overview

The following Compensation Discussion and Analysis, or CD&A, provides information about the compensation program for our principal executive officer, principal accounting officer and our other three most highly-compensated executive officers (collectively, the "named executive officers" or "NEOs"), and is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. This CD&A provides a general description of the material elements of our compensation program and specific information about its various components. As of June 2016, our independent directors will determine any material changes to the compensation of our named executive officers. See "Board of Directors and Committees" above.

Although this CD&A focuses on the information in the tables below and related footnotes, as well as the supplemental narratives relating to the fiscal year ended December 31, 2016, we also describe compensation actions taken after the last completed fiscal year to the extent it enhances the understanding of our named executive officer compensation disclosure.

Compensation Philosophy and Objectives

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

- Encourage growth in our oil and natural gas reserves and production;
- Encourage growth in cash flow and profitability;
- Mitigate risks in our business related to compensation by balancing fixed compensation with short-term and potentially long-term incentive compensation; and
- Enhance total stockholder returns through a compensation program that attracts and retains highly qualified executive officers.

Elements of Our Compensation Program

Element	Characteristics	Primary Objective
Base Salary	Cash	Retain and attract highly talented individuals
Short-Term Incentives	Cash bonus	Reward for individual and corporate performance
Long-Term Incentives	Equity awards vesting over a period of time or based on performance metrics	Align the interests of our employees and shareholders by providing employees with incentive to perform technically and financially in a manner that promotes share price appreciation. The Board is currently evaluating the use of long-term incentives.
Other Benefits	401(k) matching plans and employee health benefit plans	Provide benefits that promote employee health and support employees in attaining financial security

Base Salary. Base salary is the principal fixed component of our compensation program, and has historically been reviewed in the first quarter of each year. It is intended to provide our named executive officers with a regular source of income to compensate them for their day-to-day efforts in managing the Company. Base salary is primarily used to retain and attract highly talented individuals. Base salary varies depending on the named executive officer's experience, responsibilities, education, professional standing in the industry, changes in the competitive marketplace and the importance of the position to the Company.

Due to low commodity prices prevailing in the oil and gas industry, no salary increases were granted to named executive officers or other staff in 2015 or 2016. In January 2016, the Board and our Chief Executive Officer further considered the continued low commodity prices and, with the approval of our Board, implemented certain company-wide staffing and salary reductions, effective

February 1, 2016. These salary reductions applied to most officers and employees, excep t where an officer or employee assumed significant added responsibility. The following table shows the base salaries for our named executive officers in 2016 and 2017.

Name	2016 Base Salary ($)	2017 Base Salary ($)
Frank A. Lodzinski	229,500	229,500
Robert J. Anderson	235,000	235,000
Timothy D. Merrifield	211,500	211,500
Ray Singleton	207,900	207,900
G. Bret Wonson (1)	167,000	—
Tony Oviedo (2)	—	220,000

(1) Resigned effective February 9, 2017.

(2) Appointed Executive Vice President – Accounting and Administration effective February 9, 2017.

Elements of Our Compensation Program

Short-Term Incentives. Short-term incentive compensation is the short-term variable portion of our compensation program and is based on the principle of pay-for-performance. Short-term incentives have historically been reviewed in the first quarter of each year or at the end of the fourth quarter. The objective of short-term incentives is to reward our named executive officers based on the performance of the Company as a whole and the contributions of the individual named executive officer in relation to our success. The Company has not paid any material short-term incentives, for the years ended December 31, 2015 or 2016, although the named executive officers did participate in bonuses totaling 5% of base salary paid to all employees in December of 2016.

Long-Term Incentives. Long-term incentives may be awarded to our named executive officers under the Earthstone Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan"), which was originally approved by our stockholders in December 2014. Under our 2014 Plan, the Board has the flexibility to choose among a number of forms of long-term incentive compensation, including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance units, performance shares, or other incentive awards. In the past, the Company has granted restricted stock awards to employees and non-employee directors under prior Company equity plans.

On June 1, 2016, the Board approved awards of restricted stock units ("RSUs") to our named executive officers after considering that the base salary levels of our named executive officers are well below industry peers and further considering that no short-term incentives were paid for 2015. The following table shows the restricted stock unit awards granted to our named executive officers on June 1, 2016:

Name	Number of RSUs Vesting on January 1, 2017	Aggregate Number of RSUs Vesting on a Monthly Basis Beginning on January 31, 2017	Total
Frank A. Lodzinski	50,000	100,000	150,000
Robert J. Anderson	25,000	50,000	75,000
Timothy D. Merrifield	23,500	46,500	70,000
Ray Singleton	21,500	43,500	65,000
G. Bret Wonson *	8,334	16,666	25,000

* The restricted stock unit award for Mr. Wonson would have vested as to one-third on April 1, 2017 and the remaining two-thirds would have vested in 24 equal monthly installments beginning on April 30, 2017. However, Mr. Wonson resigned from all positions with the Company in February 2017, forfeiting all RSU's.

Other Benefits. All employees may participate in our 401(k) Retirement Savings Plan ("401(k) Plan"). Each employee may make before-tax contributions in accordance with the limits established by the Internal Revenue Service. We provide our 401(k) Plan to help our employees attain financial security by providing them with a program to save a portion of their cash compensation for retirement in a tax efficient manner. Our matching contribution is an amount equal to 100% of the employee's elective deferral contribution not to exceed 6% of the employee's compensation. Due to low commodity prices, effective April 1, 2016, matching contributions were suspended.

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

Roles of our CEO and the Board

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

Factors Considered in Setting Executive Compensation

To achieve the objectives of our compensation program, the Board believes that the compensation of each of our named executive officers should reflect the performance of the Company as a whole and the contributions of the individual named executive officer in relation to our success. In other words, our compensation program is based on the idea of pay for performance. The following is a summary of the factors considered in setting compensation for our named executive officers in addition to the factors discussed above under each element of our compensation program.

Compensation Risks. The Board reviewed the policies and practices of our compensation program, including, among other things, the types and level of our compensation in relation to the Company as a whole and on a per division basis and the fixed and variable aspects of our compensation. The Board does not believe that our compensation program encourages our named executive officers to take unreasonable risks related to our business. Based upon the Board's review, the Board concluded that there are no compensation related risks that are reasonably likely to have a material adverse effect on the Company.

Lean Management Team. The Board takes into consideration that the Company operates with a lean management team requiring each named executive officer to have significant responsibilities.

Other Compensation Practices

Accounting and Tax Considerations. Our Board reviews and takes into account current tax, accounting and securities regulations as they relate to the design of our compensation programs and related decisions. Section 162(m) of the Internal Revenue Code imposes a limit, with certain exceptions, on the amount that a publicly held corporation may deduct in any tax year for individual compensation to certain executives of such corporation exceeding $1,000,000 in any taxable year, unless the compensation is performance-based. We have no individuals with non-performance based compensation paid in excess of the Internal Revenue Code Section 162(m) tax deduction limit.

Stock Ownership Guidelines and Pledging Limitations. We do not currently have ownership requirements or a stock retention policy for our named executive officers or non-management directors. The Board has adopted a policy requiring our named executive officers and members of the Board to obtain Board approval prior to pledging, or using as collateral, our common stock in order to secure personal loans or other obligations, which includes holding shares of our common stock in a margin account.

We will continue to review periodically best practices in this area and re-evaluate our position with respect to stock ownership guidelines and pledging limitations.

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

No Employment Agreements. We have no employment contracts in place with any of our named executive officers, each of whom serve at the will of our Board. The company may consider employment contracts for named executive officers in the future.

Summary Compensation Table

The following table presents, for the years ended December 31, 2016 and 2015, for the nine month period from April 1, 2014 to December 31, 2014 (the "Stub Period"), and for the year ended March 31, 2014, the compensation of Mr. Lodzinski, our principal executive officer; Mr. Wonson, our principal financial officer during the years ended December 31, 2016 and 2015; and Messrs. Anderson, Merrifield and Singleton, our three most highly-compensated executive officers (other than the principal executive officer and principal financial officer) during the years ended December 31, 2016 and 2015 (collectively, the "named executive officers" or "NEOs"). There has been no compensation awarded to, earned by or paid to any employees required to be reported in any table or column in the fiscal years covered by any table, other than what is set forth in the following table:

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards (2) ($)	Non-equity incentive plan compensation (3) ($)	All Other Compensation ($)	Total ($)
Frank A. Lodzinski	2016	$ 231,625	$ 11,475	$ 1,833,000	$ —	$ 3,810	$ 2,079,910
President, Chairman and Principal Executive Officer	2015	$ 255,000	$ —	$ —	$ —	$ 3,185 (7)	$ 258,185
	Stub Period (4)	$ 8,543	$ 100,000 (1)	$ —	$ —	$ —	$ 108,543
Robert J. Anderson	2016	$ 235,000	$ 11,750	$ 916,500	$ —	$ 3,525	$ 1,166,775
Executive Vice President, Corporate Development and Engineering	2015	$ 235,000	$ —	$ —	$ —	$ 15,900 (8)	$ 250,900
	Stub Period (4)	$ 7,814	$ 100,000 (1)	$ —	$ —	$ 545 (8)	$ 108,359
Timothy D. Merrifield	2016	$ 213,458	$ 10,575	$ 855,400	$ —	$ 3,349	$ 1,082,782
Executive Vice President, Geological and Geophysical	2015	$ 235,000	$ —	$ —	$ —	$ 15,900 (8)	$ 250,900
	Stub Period (4)	$ 7,844	$ 95,000 (1)	$ —	$ —	$ 476 (8)	$ 103,320
Ray Singleton (5)	2016	$ 209,825	$ 10,395	$ 794,300	$ —	$ 3,234	$ 1,017,754
Executive Vice President, Northern Region	2015	$ 231,000	$ —	$ —	$ —	$ 13,283 (8)	$ 244,283
	Stub Period	$ 173,250	$ 9,625	$ 23,111	$ 188,923	$ 6,512 (6)	$ 401,421
	2014	$ 231,000	$ —	$ 22,044	$ 188,923	$ 9,495 (6)	$ 451,462
G. Bret Wonson	2016	$ 167,833	$ 8,850	$ 332,500 $(9)	$ —	$ 2,555	$ 511,738
Chief Accounting Officer and Principal Financial Officer	2015	$ 177,000	$ —	$ —	$ —	$ 13,508 (8)	$ 190,508

(1) Bonus amounts were earned prior to the closing of the Exchange Agreement; however, the Company paid the bonuses in January 2015.

(2) Amount shown represents the grant date fair value of the shares of restricted stock granted during 2016, 2015 and 2014. These amounts were calculated based on the closing market price for our shares on the NYSE MKT on the date of grant.

(3) Includes $188,923 earned for the fiscal year ended March 31, 2014, and $188,923 during the Stub Period under our performance bonus plan, which was paid in July 2014 but was related to performance for the year ended March 31, 2014.

(4) Information for Mr. Lodzinski, Mr. Anderson and Mr. Merrifield represents the period from December 19, 2014, the date upon which they became employees of the Company, through December 31, 2014.

(5) Mr. Singleton was the Company's President and Chief Executive Officer during 2014 and for the Stub Period through the closing of the Exchange Agreement on December 19, 2014.

(6) Amounts include (i) matching funds contributed by the Company to Mr. Singleton's 401(k) plan account of $5,323 for the Stub Period, and $8,019 for the fiscal year ended March 31, 2014, and (ii) $1,189 for the Stub Period, and $1,476 for premiums paid by the Company on a life insurance policy for Mr. Singleton during fiscal year ended March 31, 2014, which provides for payment of a death benefit to Mr. Singleton's designated beneficiary.

(7) Amount shown represents premiums paid by the Company related to a life insurance policy for Mr. Lodzinski.

(8) Amounts shown represent matching funds contributed by the Company to the officer's 401(k) plan accounts.

(9) Mr. Wonson resigned from all positions with the Company in February 2017. All of his outstanding RSUs were unvested and forfeited in connection with his resignation.

Outstanding Equity Awa rds at Year End

The following table provides information concerning unvested restricted stock awards and equity incentive plan awards for our named executive officers as of December 31, 2016.

	Stock Awards	
Name	Number of shares or units of stock that have not vested (#) (1)	Market value of shares or units of stock that have not vested ($) (2))
Frank A. Lodzinski	150,000	2,061,000
Robert J. Anderson	75,000	1,030,500
Timothy D. Merrifield	70,000	961,800
Ray Singleton	65,000	893,100
G. Bret Wonson	25,000	343,500

(1) Represents restricted stock units granted in 2016 which vest monthly throughout 2017, with the exception of Mr. Wonson's which were forfeited in February 2017 upon his resignation.

(2) Amount shown represents the fair value of the shares of restricted stock based on the closing market price of our shares on the NYSE MKT on December 30, 2016, which was $13.74.

The table below shows the vesting dates for the respective unvested restricted stock units listed in the above Outstanding Equity Awards at Year End table:

Vesting date	Lodzinski	Anderson	Merrifield	Singleton	Wonson
January 1, 2017	50,000	25,000	23,500	21,500	—
12 equal monthly installments on the last day of the month, beginning January 31, 2017	8,333	4,167	3,875	3,625	—
April 1, 2017	—	—	—	—	8,334
24 equal monthly installments on the last day of the month, beginning April 30, 2017	—	—	—	—	694

Grants of Plan-Based Awards

The following table provides information about time-based restricted stock unit awards granted under the 2014 Plan to our named executive officers during the year ended December 31, 2016. For named executive officers other than Mr. Wonson, the restricted stock unit awards vest as to one-third of the award on January 1, 2017 and thereafter in 12 equal monthly installments beginning on January 31, 2017. Each restricted stock unit represents a continent right to one share of our common stock. Restricted stock units are generally settled and common shares issued on a quarterly basis shortly after the end of each calendar quarter.

Name	Number of RSUs Vesting on January 1, 2017	Aggregate Number of RSUs Vesting on a Monthly Basis Beginning on January 31, 2017	Total
Frank A. Lodzinski	50,000	100,000	150,000
Robert J. Anderson	25,000	50,000	75,000
Timothy D. Merrifield	23,500	46,500	70,000
Ray Singleton	21,500	43,500	65,000
G. Bret Wonson *	8,334	16,666	25,000

* Mr. Wonson resigned from all positions with the Company in February 2017. All of his outstanding RSUs were unvested and forfeited in connection with his resignation. One-third of the RSU award for Mr. Wonson was to vest on April 1, 2017 and the remaining two-thirds were to vest in 24 equal monthly installments beginning on April 30, 2017.

Employment Contracts and Termination of Employment

We do not have any employment agreements with our named executive officers. The restricted stock unit agreements under which we have granted restricted stock unit awards under the 2014 Plan contain provisions providing for accelerated vesting upon the death or disability of the executive officer and upon termination of employment by the Company without cause or termination of employment by the executive officer for "good reason."

For purposes of the restricted stock unit agreements, the term "good reason" means without the executive officer's written consent (A) a material reduction in the executive officer's authority, duties or responsibilities compared to the executive officer's authority, duties and responsibilities as of the grant date; (B) the executive officer's principal work location being moved more than 35 miles, from the Company's current location in The Woodlands, Texas; (C) the Company or any of its subsidiaries materially reduces the executive officer's base salary (unless the base salaries of substantially all other senior executives of the Company are similarly reduced); or (D) if the executive officer is a party to an employment agreement with the Company, any material breach of such employment agreement by the Company. Termination for good reason by the executive requires prior written to the Company and the opportunity for the Company to cure. For purposes of the restricted stock unit agreements, the term "**Cause**" means (A) the executive officer's failure to perform (other than due to disability or death) the duties of the executive officer's position (as they may exist from time to time) to the reasonable satisfaction of the Company or any of its subsidiaries after receipt of a written warning and at least fifteen (15) days' opportunity for the executive officer to cure the failure, (B) any act of fraud or dishonesty committed by the executive officer against or with respect to the Company or any of its subsidiaries or customers as shall be reasonably determined to have occurred by the Board, (C) the executive officer's conviction or plea of no contest to a crime that negatively reflects on the executive officer's fitness to perform the executive officer's duties or harms the Company's or any of its subsidiaries' reputation or business, (D) the executive officer's willful misconduct that is injurious to the Company or any of its subsidiaries, or (E) the executive officer's willful violation of a material Company or any of its subsidiaries policy.

Potential Payments Triggered Upon a Change in Control

We do not have any change in control or severance agreements with any named executive officer or director. The restricted stock unit agreements under which we have granted restricted stock unit awards under our 2014 Plan contain provisions providing for accelerated vesting upon a change in control. The amounts shown in the following table reflect the potential value to our named executive officers as of December 30, 2016, of unvested restricted stock unit awards where the vesting may accelerate upon a change in control of the Company. Consistent with SEC requirements, these estimated amounts have been calculated as if the change in control had occurred as of December 30, 2016, the last business day of 2016, and using the closing market price of our common stock on December 30, 2016 ($13.74 per share). The amounts below are estimates of the incremental amounts that would be received upon a change in control; the actual amount could be determined only at the time of any actual change in control.

Estimated Potential Payments Upon a Change in Control

	Restricted Stock Units	
Name	Unvested Restricted Stock Units at 12/31/16 (#)	Total Value of Unvested Restricted Stock Units that May Accelerate Upon Change in Control ($) (1)
Frank A. Lodzinski	150,000	2,061,000
Robert J. Anderson	75,000	1,030,500
Timothy D. Merrifield	70,000	961,800
Ray Singleton	65,000	893,100
G. Bret Wonson (2)	25,000	343,500

(1) Amount shown represents the fair value of the shares of restricted stock based on the closing market price for our shares on the NYSE MKT on December 30, 2016, which was $13.74.

(2) Mr. Wonson resigned from all positions with the Company in February 2017. All of his outstanding RSUs were unvested and forfeited in connection with his resignation.

Director Compensation

Directors who are employees of the Company receive no additional compensation for serving on the Board. On July 27, 2016, the Board adopted effective as of April 1, 2016, the following compensation program for two of the non-employee members of the Board, Jay F. Joliat and Zachary G. Urban: (i) an annual cash retainer of approximately $40,000, and (ii) an initial equity grant of 9,000 shares and annual equity grants, thereafter, with a fair market value of approximately $50,000 at the time of grant. In addition, the audit committee chair will be entitled to receive an additional $8,000 cash payment annually. On June 1, 2016, the Board granted Messrs. Joliat and Urban restricted stock unit awards under the 2014 Plan. In October 2016, the Board approved the above compensation program for Mr. Kramer and granted a restricted stock award to him. Restricted stock units are generally settled and common shares is sued on a quarterly basis shortly after the end of each calendar quarter.

Director Compensation in 2016

The following table sets forth the aggregate compensation paid to our non-employee directors during year ended December 31, 2016:

Name	Fees Earned or Paid in Cash ($)	Stock Awards (1) ($)	Total ($)
Jay F. Joliat	36,000	109,980	145,980
Phil D. Kramer	—	90,180	90,180
Douglas E. Swanson, Jr.	—	—	—
Brad A. Thielemann	—	—	—
Zachary G. Urban	30,000	109,980	139,980
Robert L. Zorich	—	—	—

(1) Reflects the full grant date fair value of restricted stock unit awards granted in 2016 calculated in accordance with FASB ASC Topic 718. For a discussion of valuation assumptions, see *Note 10. Stock Based Compensation*, in the Notes to Consolidated Financial Statements included in this report. Messrs. Joliat, Kramer and Urban were granted 9,000 restricted stock units that vest as to 3,000 units on January 1, 2017 and the remaining 6,000 units in 12 equal monthly installments beginning on January 31, 2017. Each restricted stock unit represents the contingent right to receive one share of our common stock.

The following table presents the number of outstanding restricted stock units held by certain of our non-employee directors as of December 31, 2016:

Name	Number of Shares Subject to Restricted Stock Units Outstanding As of December 31, 2016
Jay F. Joliat	9,000
Phil D. Kramer	9,000
Douglas E. Swanson, Jr.	—
Brad A. Thielemann	—
Zachary G. Urban	9,000
Robert L. Zorich	—

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

The following table includes all holdings of our common stock as of March 1, 2017, of our directors and our named executive officers, our directors and named executive officers as a group, and all those known by us to be beneficial owners of more than five percent of our common stock. Unless otherwise noted, the mailing address of each person or entity named below is 1400 Woodloch Forest Drive, Suite 300, The Woodlands, Texas 77380.

Name	Common Stock (1)		Percent (2)	
Named Executive Officers:				
Frank A. Lodzinski (3)	107,834	(3)(4)(5)	*	(3)
Robert J. Anderson (3)	41,666	(3)(5)	*	(3)
Timothy D. Merrifield (3)	39,000	(3)(5)	*	
Ray Singleton (6)	498,669	(5)	2.2%	
Tony Oviedo	—		—	
Non-Management Directors:				
Jay F. Joliat (3)	15,000	(5)	*	
Phil D. Kramer	5,000	(5)	*	
Douglas E. Swanson, Jr (3)(7)	9,162,452		41.1%	
Brad A. Thielemann	—		—	
Zachary G. Urban (3)	5,000	(5)	*	
Robert L. Zorich (3)(7)	9,162,452		41.1%	
Officers and Directors as a Group (eleven persons):	9,874,621		44.3%	
Beneficial Owners of More than Five Percent:				
Oak Valley Resources, LLC (3)(7)	9,162,452		41.1%	
Flatonia Energy, LLC (8)	2,957,288		13.3%	

* Less than one percent.

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

(2) The percentage is based upon 22,289,177 shares of common stock issued as of March 1 , 2017.

(3) These officers and directors own non-controlling membership interests in OVR. OVR directly owns 9,162,452 shares or 41.1% of our outstanding voting equity securities. Messrs. Lodzinski and Anderson are two of the five members of the board of managers of OVR. Entities affiliated with Messrs. Joliat and Urban are non-controlling members of OVR. Messrs. Anderson and Merrifield, and an entity controlled by Mr. Lodzinski are members of Oak Valley Management, LLC, which is a non-controlling member of OVR. Messrs. Lodzinski, Anderson, Merrifield, Joliat and Urban, and the entities affiliated with them, do not have the sole or shared power to vote or dispose of the shares of common stock held by OVR. Mr. Lodzinski is also a director of the Company. Additionally, Messrs. Swanson and Zorich serve as directors of the Company and as managers of OVR and do not have the sole or shared power to vote or dispose of the common stock held by OVR. Messrs. Swanson and Zorich are each a managing partner of EnCap Partners and may be deemed to beneficially own the reported securities held by OVR. Each of Messrs. Swanson and Zorich disclaim beneficial ownership of such securities, except to the extent of their respective pecuniary interest therein.

(4) Includes 24,500 shares of common stock held in the name of Azure Energy, LLC (“Azure”). Mr. Lodzinski disclaims beneficial ownership of the shares held by Azure, except to the extent of his pecuniary interests therein.

(5) Represents the following number of restricted stock units that have vested or will vest within 60 days of the date of this table with each restricted stock unit representing the contingent right to receive one share of our common stock: Mr. Lodzinski – 16,667; Mr. Anderson – 8,333; Mr. Merrifield – 7,750; Mr. Singleton – 7,250; Mr. Joliat – 1,000; Mr. Kramer – 1,000; Mr. Urban – 1,000; and all directors and named executive officers as a group – 43,584.

(6) Mr. Singleton’s address is c/o Earthstone Energy, Inc., 633 Seventeenth Street, Suite 2320, Denver, Colorado 80202.

(7) Five affiliated investment funds (the “EnCap Oak Valley Funds”), specifically EnCap Energy Capital Fund VII, L.P. (“EnCap Fund VII”), EnCap Energy Capital Fund VI, L.P. (“EnCap Fund VI”), EnCap VI-B Acquisitions, L.P. (“EnCap Fund VI -B”), EnCap Energy Capital Fund V, L.P. (“EnCap Fund V”), and EnCap V-B Acquisitions, L.P. (“EnCap Fund V-B”), each a Texas limited partnership, collectively own a majority of the member ship interests of OVR and have the contractual right to nominate a majority of the members of the board of managers of OVR. Therefore, the EnCap Oak Valley Funds may be deemed to beneficially own all of the reported securities held by OVR. The EnCap Oak Valley Funds collectively own 57.3% of the membership interests of OVR. Accordingly, the EnCap Oak Valley Funds may be deemed to beneficially own the reported securities. EnCap Partners, LLC (“EnCap Partners”) is the managing member of EnCap Investments Holdings, LLC (“EnCap Holdings”), which is the sole member of EnCap Investments GP, L.L.C. (“EnCap Investments GP”), which is the general partner of EnCap, which is the general partner of EnCap Equity Fund VII GP, L.P. (“EnCap Fund VII GP”), EnCap Equity Fund VI GP, L.P. (“EnCap Fund VI GP”), and EnCap Equity Fund V GP, L.P. (“EnCap Fund V GP”). EnCap Fund VII GP is the general partner of EnCap Fund VII. EnCap Fund VI GP is the general partner of EnCap Fund VI. EnCap Fund VI GP is also the general partner of EnCap Energy Capital Fund VI-B, L.P. (“EnCap Capital Fund VI-B”), which is the sole member of EnCap VI-B Acquisitions GP, LLC (“EnCap VI-B Acquisitions GP”), which is the general partner of EnCap Fund VI-B. EnCap Fund V GP is the general partner of EnCap Fund V. EnCap Fund V GP is also the general partner of EnCap Energy Capital Fund V-B, L.P. (“EnCap Capital Fund V-B”), which is the sole member of EnCap V-B Acquisitions GP, LLC (“EnCap V-B Acquisitions GP”), which is the general partner of EnCap Fund V-B. Therefore, EnCap Partners, EnCap Holdings, EnCap Investments GP, EnCap, EnCap Fund VII GP, EnCap Fund VI GP, EnCap Fund V GP, EnCap Capital Fund V-B, EnCap Capital Fund VI-B, EnCap VI-B Acquisitions GP and EnCap V-B Acquisitions GP may be deemed to beneficially own the listed securities. Messrs. Swanson and Zorich do not have the sole or shared power to vote or dispose of our common stock held by the EnCap Oak Valley Funds. Messrs. Swanson and Zorich are each a managing partner of EnCap Partners and may be deemed to beneficially own the reported securities held by the EnCap Oak Valley Funds. Each of Messrs. Swanson and Zorich disclaim beneficial ownership of such securities except to the extent of their respective pecuniary interest therein. The address for the EnCap entities listed above is 1100 Louisiana Street, Suite 4900, Houston, Texas 77002.

(8) Flatonia Holdings, LLC (“Flatonia Holdings”) is the direct and indirect owner of 100% of the membership interests of Flatonia Energy, LLC (“Flatonia”). Three affiliated entities, specifically Energy Recapitalization and Restructuring Fund, L.P. (“ERR”), ERR FI Flatonia Holdings, LLC (“ERR FI Flatonia Holdings”), and ERR FI II Flatonia Intermediate, L.P. (“ERR FI II Flatonia Intermediate”) collectively own 59.6% of the membership interests of Flatonia Holdings. ERR FI Flatonia Holdings is an indirect wholly owned subsidiary of Energy Recapitalization and Restructuring FI Fund, L.P. (“ERR FI”). ERR FI II Flatonia Intermediate is an indirect wholly owned subsidiary of Energy Recapitalization and Restructuring FI II Fund, L.P. (“ERR FI II” and, together with ERR and ERR FI, collectively, the “ERR Funds”). Parallel Resource Partners, LLC (“Parallel”) serves as the general partner of, and has the power to direct the affairs of, each of the ERR Funds. Parallel also serves as the manager of Flatonia Holdings and owns, directly or indirectly, 1.5% of the membership interests of Flatonia Holdings. The board of managers of Parallel consists of Clint D. Carlson, C. John Wilder, Jr., Ron Hulme, John K. Howie, and Jonathan Siegler. Together, Carlson Energy Partners I, LLC (“CEP I”) and Bluescape Energy Partners LLC (“BEP”) have the power to direct the affairs of Parallel. Additionally, CEP I and BEP each own 50% of the outstanding membership interests of Parallel. Together, Carlson Energy Corp. (“Carlson Corp”), Ron Hulme and John K. Howie have the power to direct the affairs of CEP I. Mr. Clint D. Carlson has the power to direct the affairs of Carlson Corp. Bluescape Resources Company LLC (“Bluescape Resources”) has the power to direct the affairs of BEP. Mr. C. John Wilder, Jr. has the power to direct the affairs of Bluescape Resources. The address of Flatonia is c/o Parallel Resource Partners, LLC, 919 Milam Street, Suite 550, Houston, Texas 77002.

Equity Compensation Plan Information

Long-Term Incentive Plan

In December 2014, the Company’s stockholders approved and adopted, effective on December 19, 2014, the 2014 Long-Term Incentive Plan (the “2014 Plan”), which remains in effect until December 18, 2024. In October 2015, the 2014 Plan was amended to increase the number of shares of the Company’s common stock authorized to be issued to 1,500,000. Under the 2014 Plan, the board of directors is authorized to grant stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, performance bonuses, stock awards and other incentive awards to the Company’s employees or those of its subsidiaries or affiliates as well as persons rendering consulting or advisory services and non-employee directors, subject to the conditions set forth in the amended 2014 Plan.

The following table sets forth information with respect to the equity compensation plan available to non-employee directors, officers, employees and consultants at December 31, 2016:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	781,500	$ 12.53	718,500
Equity compensation plans not approved by security holders	—	$ —	—

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

Flatonia Energy, LLC

Flatonia Energy, LLC ("Flatonia"), a subsidiary of Parallel Resources, LLC ("PRP"), which owns approximately 13.3% of our common stock, is a party to an industry standard joint operating agreement (the "Operating Agreement") with Earthstone Operating, LLC ("OVO") one of our wholly owned subsidiaries. This agreement was entered into prior to the closing of the Flatonia Contribution Agreement on December 19, 2014 under which PRP acquired shares of our common stock. The Operating Agreement covers certain jointly owned oil and gas properties located in the Eagle Ford trend in Texas. During the year ended December 31, 2016, Flatonia paid us $21.7 million as its share of joint operating costs associated with these properties which reflects charges by OVO for its direct costs and operating expenses under the joint Operating Agreement. During 2016, OVO paid $26.6 million to Flatonia for its share of net revenues associates with these properties.

Oak Valley Resources, LLC

Various members of our Board of Directors and management hold investments in entities that own membership interests in OVR. For instance, Mr. Lodzinski owns an approximate 28.4% interest in an entity that owns a 2.6% membership interest in OVR. Messrs. Swanson and Zorich are associated with EnCap Investments L.P., which advises the EnCap Funds, the majority investors in OVR. Messrs. Joliat and Urban own membership interests in OVR.

Policies and Procedures for Approval of Related Party Transactions

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

Director Independence

OVR, listed under the "Security Ownership of Certain Beneficial Owners and Management" section, holds stock representing a significant amount of our outstanding shares of common stock. From December 2014 to June 2016, we were a "controlled company" for purposes of the NYSE MKT rules and were not required to have a majority of independent directors on the Board or to comply with the requirements for compensation and nominating/governance committees. However, under the NYSE MKT transition rules, because we are no longer a controlled company, our Board must be comprised of a majority of independent directors within one year of June 21, 2016, the date on which we no longer qualified as a controlled company.

The current Board consists of eight directors, two of whom are currently employed by the Company (Messrs. Lodzinski and Singleton). In March 2017, the Board conducted an annual review and affirmatively determined that certain non-employee directors (Messrs. Joliat, Kramer, Thielemann and Urban) are "independent" as that term is defined in the listing standards of the NYSE MKT. The Board made a subjective determination as to each independent director that no relationship exists, which, in the opinion of the Board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. In making these determinations, the Board reviewed and discussed information provided with regard to each director's business and personal activities as they may relate to the Company and its management. Further, the Board determined that Mr. Lo dzinski is not independent because he is the President and Chief Executive Officer of the Company and Mr. Singleton is not independent because he is the Executive Vice President Northern Region. Further, the Board determined that Messrs. Swanson and Zorich are not independent because they are affiliates of OVR, which beneficially owns approximately 41.1% of our common stock. See “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.”

Item 14. Principal Accountant Fees and Services

The Audit Committee of the Board of Directors has retained Grant Thornton LLP (“GT”) as our independent public accounting firm (our independent auditor). GT audited our consolidated financial statements for the year ended December 31, 2016.

The audit report of GT on our consolidated financial statements as of and for the year ended December 31, 2016 did not contain an adverse opinion or disclaimer of opinion, and was not qualified or modified as to uncertainty, audit scope or accounting principles. Weaver did issue an adverse opinion on our internal control over financial reporting due to a material weakness related to segregation of duties.

Weaver and Tidwell, L.L.P. (“Weaver”) served as the independent registered public accounting firm for the Company for the year ended December 31, 2015 and 2014, and for the subsequent interim period through June 30, 2016. On July 13, 2016, the Company dismissed Weaver and engaged GT to serve as the Company’s independent registered public accounting firm. The decision to change accountants was recommended by the Audit Committee and approved by the Board of Directors.

Audit Committee Pre-Approval Policies and Procedures

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

Fees Paid to GT and Weaver

The following is a summary and description of fees for services provided by GT for the year ended December 31, 2016, and by Weaver for the years ended December 31, 2016 and 2015:

	Year Ended December 31, 2016		Year Ended December 31, 2015
Services	**Fees Paid to GT**	**Fees Paid to Weaver**	**Fees Paid to Weaver**
Audit Fees (1)	$ 532,556	$ 25,000	$ 447,000
Audit-Related Fees (2)	21,200	30,000	—
Tax Fees	—	—	—
All Other Fees	—	—	—
Total	$ 553,756	$ 55,000	$ 447,000

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

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

PART IV

Item 15. Exhibits, Financial Statements and Schedules

Exhibit No.	Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
2.1	Arrangement Agreement, dated December 16, 2015, among Earthstone Energy, Inc., 1058286 B.C. Ltd. and Lynden Energy Corp.	8-K	001-35049	2.1	December 17, 2015		
2.1(a)	First Amendment to Arrangement Agreement dated March 29, 2016, among Earthstone Energy, Inc., 1058286 B.C. Ltd. And Lynden Energy Corp.	8-K	001-35049	2.1	March 29, 2016		
2.2	Contribution Agreement dated November 7, 2016, by and amoung Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, Lynden USA Inc., Lynden USA Operating, LLC, Bold Energy Holdings, LLC and Bold Energy III LLC.	8-K	001-35049	2.1	November 8, 2016		
3.1	Amended and Restated Certificate of Incorporation of Earthstone Energy, Inc. dated February 26, 2010.	8-K	001-35049	3(i)	March 3, 2010		
3.1(a)	Certificate of Amendment to Certificate of Incorporation of Earthstone Energy, Inc. dated December 20, 2010.	8-K	001-35049	3(i)	January 4, 2011		
3.1(b)	Certificate of Amendment of Certificate of Incorporation of Earthstone Energy, Inc. dated December 19, 2014.	8-K	001-35049	3.1	December 29, 2014		
3.1(c)	Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Earthstone Energy, Inc. dated October 22, 2015.	8-K	001-35049	3.1	October 26, 2015		
3.2	Amended and Restated Bylaws of Earthstone Energy, Inc. dated February 26, 2010.	8-K	001-35049	3(ii)	March 10, 2010		
3.2(a)	First Amendment to the Amended and Restated Bylaws of Earthstone Energy, Inc. dated November 22, 2011.	8-K	001-35049	3(ii)c	November 23, 2011		
3.2(b)	Second Amendment to the Amended and Restated Bylaws of Earthstone Energy, Inc. dated October 22, 2015.	8-K	001-35049	3.2	October 26, 2015		
4.1	Rights Agreement dated February 4, 2009 between Earthstone Energy, Inc. and Corporate Stock Transfer, Inc.	8-K	001-35049	4.1	February 5, 2009		
4.1(a)	First Amendment to the Rights Agreement dated May 15, 2014, by and among Earthstone Energy, Inc., Corporate Stock Transfer, Inc., and Direct Transfer LLC.	8-A/A	001-35049	4.1	May 16, 2014		

4.1(b)	Second Amendment to the Rights Agreement dated May 15, 2014 between Earthstone Energy, Inc. and Direct Transfer LLC.	8-A/A	001-35049	4.2	May 16, 2014	
4.1(c)	Third Amendment to the Rights Agreement dated October 16, 2014 between Earthstone Energy, Inc. and Direct Transfer LLC.	8-A/A	001-35049	4.1	October 20, 2014	
4.2	Specimen Common Stock Certificate of Earthstone Energy, Inc.	10-K	001-35049	4.2	June 16, 2011	
10.1	Credit Agreement dated December 19, 2014, by and among Earthstone Energy, Inc., Oak Valley Operating, LLC, EF Non-OP, LLC, Sabine River Energy, LLC, Basic Petroleum Services, Inc., BOKF, NA dba Bank of Texas, and the Lenders party thereto.	8-K	001-35049	10.4	December 29, 2014	
10.1(a)	First Amendment to the Credit Agreement dated December 19, 2014, by and among Earthstone Energy, Inc., Oak Valley Operating, LLC, EF Non-OP, LLC, Sabine River Energy, LLC, Basic Petroleum Services, Inc., BOKF, NA dba Bank of Texas, and the Lenders party thereto.	8-K	001-35049	10.1	December 4, 2015	
10.1(b)	Second Amendment to the Credit Agreement dated May 18, 2016, by and among Earthstone Energy, Inc., Earthstone Operating, LLC, EF Non-OP, LLC, Sabine River Energy, LLC, Basic Petroleum Services, Inc., Lynden Energy Corp., Lynden USA, Inc., BOKF, NA dba Bank of Texas, and the Lenders party thereto.	8-K	001-35049	10.1	May 18, 2016	
10.1(c)	Third Amendment and Limited Waiver to the Credit Amgreement dated July 27, 2016, by and among Earthstone Energy, Inc., Earthstone Operating, LLC, EF Non-OP, LLC, Sabine River Energy, LLC, Basic Petroleum Services, Inc., Lynden Energy Corp., Lynden USA, Inc., BOKF, NA dba Bank of Texas, and the Lenders party thereto.	8-K	001-35049	10.1	July 27, 2016	
10.2	Exchange Agreement dated May 15, 2014 between Earthstone Energy, Inc. and Oak Valley Resources, LLC.	8-K	001-35049	10.1	May 16, 2014	
10.2(a)	Amendment to the Exchange Agreement dated September 26, 2014 between Earthstone Energy, Inc. and Oak Valley Resources, LLC.	8-K	001-35049	10.1	October 2, 2014	
10.3	Contribution Agreement dated October 16, 2014, among Earthstone Energy, Inc., Oak Valley Resources, LLC, Sabine River Energy, LLC, Oak Valley Operating, LLC, Parallel Resource Partners, LLC, and Flatonia Energy, LLC.	8-K	001-35049	10.1	October 20, 2014	

10.3(a)	First Amendment to Contribution Agreement dated June 4, 2015, by and among Earthstone Energy, Inc., Oak Valley Resources, LLC, Sabine River Energy, LLC, Earthstone Operating, LLC, Parallel Resources Partners, LLC, and Flatonia Energy, LLC.	8-K	001-35049	10.1	June 10, 2015		
10.4	Registration Rights Agreement dated December 19, 2014 between Earthstone Energy, Inc. and Oak Valley Resources, LLC.	8-K	001-35049	10.1	December 29, 2014		
10.5	Registration Rights Agreement dated December 19, 2014, by and among Earthstone Energy, Inc., Parallel Resource Partners, LLC, Flatonia Energy, LLC, and Oak Valley Resources, LLC.	8-K	001-35049	10.2	December 29, 2014		
10.6†	Earthstone Energy, Inc. Employee Severance Compensation Plan.	8-K	001-35049	10.2	May 16, 2014		
10.7†	Earthstone Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-35049	10.3	December 29, 2014		
10.7(a)†	First Amendment to the Earthstone Energy, Inc. 2014 Long-Term Incentive Plan dated October 22, 2015.	8-K	001-35049	10.1	October 26, 2015		
10.8	Form of Indemnification Agreement.	8-K	001-35049	10.5	December 29, 2014		
10.9†	Earthstone Energy, Inc. 2011 Equity Incentive Compensation Plan.	Def. Proxy Statement	001-35049	Appendix A	July 29, 2011		
10.10†	Earthstone Energy, Inc. Performance Bonus Plan.	10-K/A	001-35049	10.3	October 9, 2009		
10.11	Form of Voting Support Agreement	8-K	001-35049	10.1	December 17, 2015		
10.12†	Form of Restricted Stock Unit Agreement (Executive Management)	8-K	001-35049	10.1	June 1, 2016		
10.13†	Form of Restricted Stock Unit Agreement (Employee)	8-K	001-35049	10.2	June 1, 2016		
10.14†	Form of Restricted Stock Unit Agreement (Non-Employee Director)	8-K	001-35049	10.3	June 1, 2016		
10.15	Voting and Support Agreement	8-K	001-35049	10.1	November 8, 2016		
14	Code of Business Conduct and Ethics.	10-KSB/A	001-35049	14.1	May 11, 2005		
21.1	List of Subsidiaries.					X	
23.1	Consent of Cawley, Gillespie & Associates, Inc.					X	
23.2	Consent of Grant Thornton LLP					X	
23.3	Consent of Weaver and Tidwell, L.L.P.					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 Accounting Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X

99.1	Report of Cawley, Gillespie & Associates, Inc.	X
101.INS*	XBRL Instance Document.	X
101.SCH*	XBRL Schema Document.	X
101.CAL*	XBRL Calculation Linkbase Document.	X
101.DEF*	XBRL Definition Linkbase Document.	X
101.LAB*	XBRL Label Linkbase Document.	X
101.PRE*	XBRL Presentation Linkbase Document.	X

† Indicates management contract or compensatory plan or arrangement.

SIGNATURES

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

EARTHSTONE ENERGY, INC.

Date: March 15, 2017

By: /s/ Frank A. Lodzinski
Name: Frank A. Lodzinski
Title: President and Chief Executive Officer
(Principal Executive Officer)

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

Signature	Title	Date
/s/ Frank A. Lodzinski Frank A. Lodzinski	Chairman of the Board, Director, President and Chief Executive Officer (Principal Executive Officer)	March 15, 2017
/s/ Tony Oviedo Tony Oviedo	Executive Vice President, Accounting and Administration (Principal Accounting Officer)	March 15, 2017
/s/ Jay F. Joliat Jay F. Joliat	Director	March 15, 2017
/s/ Phil D. Kramer Phil D. Kramer	Director	March 15, 2017
/s/ Ray Singleton Ray Singleton	Director	March 15, 2017
/s/ Douglas E. Swanson, Jr. Douglas E. Swanson, Jr.	Director	March 15, 2017
/s/ Brad A. Thielemann Brad A. Thielemann	Director	March 15, 2017
/s/ Zachary G. Urban Zachary G. Urban	Director	March 15, 2017
/s/ Robert L. Zorich Robert L. Zorich	Director	March 15, 2017

EARTHSTONE ENERGY, INC.

Index to Consolidated Financial Statements and Supplementary Information

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Earthstone Energy, Inc.

We have audited the accompanying consolidated balance sheet of Earthstone Energy, Inc. (a Delaware corporation and subsidiaries (the "Company") as of December 31, 2016, and the related consolidated statements of operations, 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 Earthstone 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 15, 2017 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Earthstone Energy, Inc.

We have audited the accompanying consolidated balance sheet of Earthstone Energy, Inc. and subsidiaries (the Company) (formerly Oak Valley Resources, LLC) as of December 31, 2015 and the related consolidated statements of operations, equity, and cash flows for each of the years in the two-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the entity's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Earthstone Energy, Inc. and subsidiaries (formerly Oak Valley Resources, LLC) as of December 31, 2015, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Weaver and Tidwell, L.L.P.

Houston, Texas
March 11, 2016

EARTHSTONE ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

ASSETS	December 31, 2016	December 31, 2015
Current assets:		
Cash	$ 10,200	$ 23,264
Accounts receivable:		
Oil, natural gas, and natural gas liquids revenues	13,998	13,529
Joint interest billings and other, net of allowance of $163 and $170 at December 31, 2016 and 2015, respectively	2,698	4,924
Derivative asset	—	3,694
Prepaid expenses and other current assets	446	498
Total current assets	27,342	45,909
Oil and gas properties, successful efforts method:		
Proved properties	363,072	283,644
Unproved properties	51,723	34,609
Total oil and gas properties	414,795	318,253
Accumulated depreciation, depletion and amortization	(145,393)	(119,920)
Net oil and gas properties	269,402	198,333
Other noncurrent assets:		
Goodwill	17,620	17,532
Office and other equipment, net of accumulated depreciation of $1,600 and $1,028 at December 31, 2016 and 2015, respectively	1,479	1,934
Other noncurrent assets	669	1,236
TOTAL ASSETS	$ 316,512	$ 264,944
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 11,927	$ 11,580
Revenues and royalties payable	10,769	8,576
Accrued expenses	5,392	12,975
Derivative liability	4,595	—
Advances	4,542	15,447
Current portion of long-term debt	1,604	—
Total current liabilities	38,829	48,578
Noncurrent liabilities:		
Long-term debt	12,693	11,191
Asset retirement obligation	6,013	5,075
Derivative liability	1,575	—
Deferred tax liability	15,776	—
Other noncurrent liabilities	169	227
Total noncurrent liabilities	36,226	16,493
Commitments and Contingencies (Note 14)		
Equity:		
Preferred stock, $0.001 par value, 20,000,000 shares authorized; none issued or outstanding	—	—
Common stock, $0.001 par value, 100,000,000 shares authorized; 22,289,177 issued and 22,273,820 outstanding at December 31, 2016 and 13,835,128 issued and 13,819,771 outstanding at December 31, 2015	23	14
Additional paid-in capital	454,202	358,086
Accumulated deficit	(212,308)	(157,767)
Treasury stock, 15,357 shares at December 31, 2016 and 2015, respectively	(460)	(460)
Total equity	241,457	199,873
TOTAL LIABILITIES AND EQUITY	$ 316,512	$ 264,944

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

EARTHSTONE ENERGY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share and per share amounts)

	Years Ended December 31,		
	2016	**2015**	**2014**
REVENUES			
Oil	$ 34,358	$ 39,849	$ 34,734
Natural gas	5,046	5,457	9,367
Natural gas liquids	2,865	2,158	3,510
Total revenues	42,269	47,464	47,611
OPERATING COSTS AND EXPENSES			
Lease operating expense	13,415	14,550	9,422
Severance taxes	2,198	2,582	2,002
Rig idle and contract termination expense	5,059	—	—
Re-engineering and workovers	1,652	872	708
Impairment expense	24,283	138,086	19,359
Depreciation, depletion and amortization	25,937	31,228	18,414
General and administrative expense	9,414	9,711	6,830
Stock-based compensation	3,301	—	—
Transaction costs	2,483	589	1,034
Accretion of asset retirement obligation	551	550	317
Exploration expense	5	142	111
Total operating costs and expenses	88,298	198,310	58,197
Gain on sale of oil and gas properties	8	1,617	—
Loss from operations	**(46,021)**	**(149,229)**	**(10,586)**
OTHER INCOME (EXPENSE)			
Interest expense, net	(1,282)	(722)	(597)
(Loss) gain on derivative contracts, net	(6,638)	6,431	4,392
Other (expense) income, net	(72)	423	62
Total other income (expense)	(7,992)	6,132	3,857
Loss before income taxes	(54,013)	(143,097)	(6,729)
Income tax expense (benefit)	528	(26,442)	22,105
Net loss	**$ (54,541)**	**$ (116,655)**	**$ (28,834)**
Net loss per common share:			
Basic	$ (2.92)	$ (8.43)	$ (3.11)
Diluted	$ (2.92)	$ (8.43)	$ (3.11)
Weighted average common shares outstanding:			
Basic	18,651,582	13,835,128	9,279,324
Diluted	18,651,582	13,835,128	9,279,324

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

EARTHSTONE ENERGY, INC.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands, except share amounts)

	Members' Equity	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock Shares	Treasury Stock Amount	Total Equity
At December 31, 2013	$ 148,922	—	$ —	—	$ —	—	$ —	$ 148,922
Contributions from Oak Valley Resources, LLC members	107,020	—	—	—	—	—	—	107,020
Contribution of Oak Valley Subsidiaries in exchange for shares	(268,220)	9,124,452	9	268,211	—	—	—	—
Reverse acquisition with Oak Valley	—	1,753,388	2	33,453		(15,357)	(460)	32,995
Shares issued in 2014 Eagle Ford Acquisition	—	2,957,288	3	56,422	—	—	—	56,425
Net loss	12,278	—	—	—	(41,112)	—	—	(28,834)
At December 31, 2014	—	13,835,128	14	358,086	(41,112)	(15,357)	(460)	316,528
Net loss	—	—	—	—	(116,655)	—	—	(116,655)
At December 31, 2015	—	13,835,128	14	358,086	(157,767)	(15,357)	(460)	199,873
Common stock issued, net of offering costs of $2.7 million	—	4,753,770	5	47,120	—	—	—	47,125
Stock-based compensation expense	—	—	—	3,301	—	—	—	3,301
Shares issued in Lynden Arrangement	—	3,700,279	4	45,695	—	—	—	45,699
Net loss	—	—	—	—	(54,541)	—	—	(54,541)
At December 31, 2016	$ —	22,289,177	$ 23	$ 454,202	$ (212,308)	(15,357)	$ (460)	$ 241,457

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

EARTHSTONE ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31, 2016	2015	2014
Cash flows from operating activities:			
Net loss	$ (54,541)	$ (116,655)	$ (28,834)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	25,937	31,228	18,414
Impairment of goodwill	17,532	1,547	—
Impairment of proved and unproved oil and gas properties	6,751	136,539	19,359
Total loss (gain) on derivative contracts, net	6,638	(6,431)	(4,392)
Operating portion of net cash received in settlement of derivative contracts	3,225	6,306	778
Rig idle and termination expense	5,059	—	—
Stock-based compensation	3,301	—	—
Accretion of asset retirement obligations	551	550	317
Deferred income taxes	528	(26,533)	22,105
Amortization of deferred financing costs	298	264	164
Settlement of asset retirement obligations	(15)	(108)	(56)
Gain on sale of oil and gas properties	(8)	(1,617)	—
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	3,807	9,246	(5,305)
Decrease (increase) in prepaid expenses and other current assets	511	779	(194)
(Decrease) increase in accounts payable and accrued expenses	(9,151)	(30,887)	28,408
Increase (decrease) in revenues and royalties payable	2,194	(8,739)	7,099
(Decrease) increase in advances	(10,905)	(5,929)	17,925
Net cash provided by (used in) operating activities	1,712	(10,440)	75,788
Cash flows from investing activities:			
Lynden Arrangement, net of cash acquired	(31,334)	—	—
Reverse acquisition with Oak Valley, net of cash acquired	—	—	(4,239)
Acquisition of oil and gas properties	—	(8,706)	(18,772)
Additions to oil and gas properties	(28,417)	(61,060)	(83,041)
Additions to office and other equipment	(117)	(378)	(1,385)
Proceeds from sale of oil and gas properties	—	3,441	—
Proceeds from sale of land	—	101	—
Net cash used in investing activities	(59,868)	(66,602)	(107,437)
Cash flows from financing activities:			
Proceeds from borrowings	36,597	—	11,191
Repayments of borrowings	(38,549)	—	(10,825)
Deferred financing costs	(81)	(141)	(613)
Contributions, net of issuance costs	—	—	106,920
Issuance of common stock, net of offering costs of $2.7 million	47,125	—	—
Net cash provided by (used in) financing activities	45,092	(141)	106,673
Net (decrease) increase in cash and cash equivalents	(13,064)	(77,183)	75,024
Cash at beginning of period	23,264	100,447	25,423
Cash at end of period	$ 10,200	$ 23,264	$ 100,447
Supplemental disclosure of cash flow information			
Cash paid for:			
Interest	$ 961	$ 415	$ 493
Non-cash investing and financing activities:			
Asset retirement obligations	$ 152	$ 150	$ 237
Accruals of property, plant and equipment	$ 2,374	$ 7,665	$ 18,219
Acquisition of oil and gas properties	$ —	$ 1,991	$ —
Promissory Note	$ 5,059	$ —	$ —
Common stock issued in Lynden Arrangement	$ 45,699	$ —	$ —
Common stock issued in 2014 Eagle Ford Acquisition	$ —	$ —	$ 56,425

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

Note 1. – Organization and Basis of Presentation

Earthstone Energy, Inc. (together with our consolidated subsidiaries, the "Company," "our," "we," "us," "Earthstone" or similar terms), a Delaware corporation, is a growth-oriented independent oil and natural gas development and production company. In addition, the Company is active in corporate mergers and the acquisition of oil and natural gas properties that have production and future development opportunities. Our operations are all in the up-stream segment of the oil and natural gas industry and all our properties are onshore in the United States.

Oak Valley Resources, LLC ("OVR") is a Delaware limited liability company formed on December 14, 2012. On December 19, 2014, the Company acquired three operating subsidiaries of OVR, in exchange for shares of Earthstone common stock (the "Exchange"). Prior to the Exchange, OVR was an independent energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas and natural gas liquids ("NGLs"), with properties in Texas, Oklahoma, and Louisiana. OVR was formed through a series of transactions that conveyed properties and committed cash contributions from various investors including EnCap Investments L.P. ("EnCap"), Wells Fargo Central Pacific Holdings, Inc. ("Wells Fargo"), VILLCo Capital II, LLC ("VILLCo") and an affiliate of OVR, Oak Valley Management, LLC ("OVM").

Certain prior-period amounts have been reclassified to conform to current-period presentation as follows:

- Consolidated Statement of Operations – Accretion of asset retirement obligation has been reclassified out of Lease operating expense and included in its own line item in Operating Costs and Expenses. Transaction costs have been reclassified out of General and administrative expense and included in its own line item in Operating Costs and Expenses. Gain on sale of oil and gas properties has be reclassified from within Revenues to its own line item to arrive at Loss from operations. Gathering income has be reclassified from within Revenues to inclusion in Lease operating expense within Operating Costs and Expenses. These reclassifications had no effect on Loss from operations, Loss before income taxes, or Net loss for each of the three years ended December 31, 2016, 2015 and 2014.
- Consolidated Statement of Cash Flows – Non-cash changes in fair value of the Company's commodity swaps have been reclassified from the Unrealized (gain) loss on derivative contracts and bifurcated into Total loss (gain) on derivative contracts, net, and Operating portion of net cash received in settlement of derivative contracts. The reclassification had no effect on Net cash provided by operating activities for each of the three years ended December 31, 2016, 2015 and 2014.

Note 2. – Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts and balances of the Company and its wholly owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). All intercompany accounts and transactions, including revenues and expenses, are eliminated in consolidation.

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with GAAP requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods then ended.

Estimated quantities of crude oil, natural gas and natural gas liquids reserves are the most significant of our estimates. All reserve data included in these Consolidated Financial Statements are based on estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and natural gas liquids. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and natural gas liquids reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil, natural gas and natural gas liquids that are ultimately recovered.

Other items subject to estimates and assumptions include, but are not limited to, the carrying amounts of property, plant and equipment, goodwill, asse t retirement obligations, valuation allowances for deferred income tax assets, and valuation of derivative instruments. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. See *Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited).*

Accounts Receivable

Accounts receivable include amounts due from crude oil, natural gas, and natural gas liquids purchasers, other operators for which the Company holds an interest, and from non-operating working interest owners. Accrued crude oil, natural gas, and natural gas liquids sales from purchasers and operators consist of accrued revenues due under normal trade terms, generally requiring payment within 60 days of production.

An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectible are charged to the allowance.

Provisions for bad debts and recoveries on accounts previously charged off are added to the allowance. The Company routinely assesses the recoverability of all material trade receivables and other receivables to determine their collectability. Allowance for uncollectible accounts receivable was $0.2 million at December 31, 2016 and 2015.

Derivative Instruments

The Company utilizes derivative instruments in order to manage exposure to commodity price risk associated with future oil and natural gas production. The Company recognizes all derivatives as either assets or liabilities, measured at fair value, and recognizes changes in the fair value of derivatives in current earnings. The Company has elected to not designate any of its positions under the hedge accounting rules. Accordingly, these derivative contracts are marked-to-market and any changes in the estimated values of derivative contracts held at the balance sheet date are recognized in *(Loss) gain on derivative contracts, net* in the Consolidated Statements of Operations as unrealized gains or losses on derivative contracts. Realized gains or losses on derivative contracts are also recognized in *(Loss) gain on derivative contracts, net* in the Consolidated Statements of Operations.

Oil and Gas Properties

The method of accounting for oil and natural gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the successful efforts method of accounting for natural gas properties as proscribed by the SEC. For more information see *Note 6. Oil and Natural Gas Properties*.

Goodwill

Goodwill represents the excess of the purchase price of assets acquired over the fair value of those assets and is tested for impairment annually, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors. During the years ended December 31, 2016 and 2015, impairments to Goodwill of $17.5 million and $1.5 million, respectively, were recorded. There were no impairments to Goodwill recorded in the year ended December 31, 2014. For further discussion, see *Note 7. Goodwill*.

Segment Reporting

The Company's operations are conducted through two locations which have been deemed operating segments under ASC 280, Segment Reporting. The Company aggregated them into one reporting segment because these operating segments sell the same products, under the same production processes, with the same type of customers, under the same method of distribution, and in the same type of regulatory environment.

Asset Retirement Obligations

Asset retirement obligations associated with the retirement of long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the asset, including the asset retirement cost, is depreciated over the useful life of the asset. Asset retirement obligations are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of asset retirement obligations change, an adjustment is recorded to both the asset retirement obligations and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. For further discussion, see *Note 12. Asset Retirement Obligations*.

Business Combinations

The Company accounts for the acquisition of oil and gas properties not commonly controlled based on the requirements of FASB ASC Topic 805, which requires an acquiring entity to recognize the assets acquired and liabilities assumed at fair value under the acquisition method of accounting, provided such assets and liabilities qualify for acquisition accounting under the standard. The Company accounts for property acquisitions of proved developed oil and gas properties as business combinations.

Revenue Recognition

Oil, natural gas, and natural gas liquids revenues represent income from the production and delivery of oil, natural gas, and natural gas liquids, recorded net of royalties. Revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has been transferred, and collectability of the revenue is probable. The Company follows the sales method of accounting for gas imbalances. The Company had no significant gas imbalances as of December 31, 2016, 2015, or 2014.

Concentration of Credit Risk

Credit risk represents the actual or perceived financial loss that the Company would record if its purchasers, operators, or counterparties failed to perform pursuant to contractual terms.

The purchasers of the Company's oil, natural gas, and natural gas liquids production consist primarily of independent marketers, major oil and natural gas companies and natural gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts. In 2016, two purchasers accounted for 41% and 19%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. In 2015 and 2014, one purchaser accounted for 62% and 60% respectively, of the Company's oil, natural gas, and natural gas liquids revenues. No other purchaser accounted for 10% or more of the Company's oil, natural gas, and natural gas liquids revenues during 2016, 2015, and 2014. Additionally, at December 31, 2016, two purchasers accounted for 28% and 12%, respectively, of the Company's oil, natural gas, and natural gas liquids receivables. At December 31, 2015, one purchasers accounted for 25% of the Company's oil, natural gas, and natural gas liquids receivables. No other purchaser accounted for 10% or more of the Company's oil, natural gas, and natural gas liquids receivables at December 31, 2016 and 2015.

The Company holds working interests in oil and gas properties for which a third party serves as operator. The operator sells the oil, natural gas, and NGLs to the purchaser, collects the cash, and distributes the cash to the Company. The Company recognizes the cash received as revenue. In 2016 and 2015, one operator distributed 19% and 12%, respectively, of the Company's oil, natural gas and natural gas liquids revenues. In 2014, a different operator distributed 20% of the Company's oil, natural gas and natural gas liquids revenues. No other operator accounted for 10% or more of the Company's oil, natural gas, and natural gas liquids revenues during 2016, 2015, and 2014.

The derivative instruments of the Company are with a small number of counterparties and, from time-to-time, may represent material assets in the Consolidated Balance Sheets. At December 31, 2016, the Company had no derivative contracts in asset positions. At December 31, 2015, two counterparties accounted for 69% and 31%, respectively, of the Company's Current derivative asset in the Consolidated Balance Sheet.

The Company regularly maintains its cash in bank deposit accounts. Balances held by the Company at its banks typically exceed Federal Deposit Insurance Corporation ("FDIC") insurance coverage and, as a result, there is a concentration of credit risk related to the amounts of deposit in excess of FDIC insurance coverage.

Income Taxes

We are a U.S. company operating in multiple states, as well as one foreign legal entity, Lynden Energy Corp., which is a Canadian company discussed in *Note 3. Acquisitions and Divestitures*. Consequently, our tax provision is based upon the tax laws and rates in effect in the applicable jurisdiction in which our operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary. Therefore, as a part of the process of preparing the consolidated financial statements, we are required to estimate the income taxes in each of these jurisdictions. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes. Our effective tax rate for financial statement purposes will continue to fluctuate from year to year as our operations are conducted in different taxing jurisdictions.

Our deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported in our Consolidated Balance Sheets. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2016 and 2015, the Company has recorded a valuation allowance for its deferred tax assets in the Consolidated Balance Sheets. The historical financials prior to December 19, 2014 are those of OVR. OVR was not subject to taxation and therefore tax provisions were not recorded on the historical consolidated financial statements. As a result of the Exchange Agreement, OVR is now a taxable entity and a charge to earnings to record a tax provision was included in the purchase accounting adjustments.

The Company applies the accounting standards related to uncertainty in income taxes. This accounting guidance clarifies the accounting for uncertainties in income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the consolidated financial statements. It requires that the Company recognize in the consolidated financial statements the financial effects of a tax position, if that position is more likely than not of being sustained upon examination, including resolution of any appeals or litigation processes, based upon the technical merits of the position. It also provides guidance on measurement, classification, interest, penalties and disclosure. The Company's tax positions related to its pass-through status and state income tax liability, including deductibility of expenses, have been reviewed by the Company's management they believe those positions would more likely than not be sustained upon examination. Accordingly, the Company has not recorded an income tax liability for uncertain tax positions at December 31, 2016, 2015 or 2014.

Recently Issued Accounting Standards

<u>Standards adopted in 2016</u>

Debt Issuance Costs – In April 2015, the Financial Accounting Standards Board ("FASB") issued updated guidance which changes the presentation of debt issuance costs in the financial statements. Under this updated guidance, debt issuance costs are presented on the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs is reported as interest expense. In August 2015, the FASB subsequently issued a clarification as to the handling of debt issuance costs related to line-of-credit arrangements that allows the presentation of these costs as an asset. The standards update was effective for interim and annual periods beginning after December 15, 2015. The Company adopted this standards update, as required, effective January 1, 2016. The adoption of this standards update did not affect the Company's method of amortizing debt issuance costs and did not have a material impact on its Consolidated Financial Statements.

Measurement-Period Adjustments – In September 2015, the FASB issued updated guidance that eliminates the requirement to restate prior periods to reflect adjustments made to provisional amounts recognized in a business combination. The updated guidance requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The standards update was effective prospectively for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The Company adopted this standard update, as required, effective January 1, 2016, which did not have a material impact on its Consolidated Financial Statements.

Stock Compensation - In March 2016, the FASB issued updated guidance on share-based payment accounting. The standards update is intended to simplify several areas of accounting for share-based compensation arrangements, including the income tax impact, classification on the statement of cash flows and forfeitures. The standards update is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. The Company elected to early-adopt this standards update as of April 1, 2016 in connection with its initial grant of awards under the Company's 2014 Long Term Incentive Plan. The Company has elected to record the impact of forfeitures on compensation cost as they occur. The Company is also permitted to withhold income taxes upon settlement of equity-classified awards at up to the maximum statutory tax rates. There was no retrospective adjustment as the Company did not have any outstanding equity awards prior to adoption. See *Note 10. Stock-Based Compensation*.

Standards not yet adopted

Revenue Recognition - In May 2014, the FASB issued updated guidance for recognizing revenue from contracts with customers. This update amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of good and services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those good or services. The Company will adopt this standards update, as required, beginning with the first quarter of 2018. The Company does not expect the adoption of this guidance to have a material impact on its Consolidated Financial Statements.

Leases – In February 2016, the FASB issued updated guidance on accounting for leases. This update requires lessees to recognize a right of use asset and lease liability on the balance sheet for all leases, with the exception of short-term leases. Entities are required to use a modified retrospective adoption, with certain relief provisions, for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements when adopted. The Company will adopt this standards update, as required, beginning with the first quarter of 2019. The Company is currently evaluating the effect of the update on our consolidated financial statements and related disclosures.

Statement of Cash Flows – In August 2016, the FASB issued updated guidance that These amendments clarify how entities should classify certain cash receipts and cash payments on the statement of cash flows related to the following transactions: (1) debt prepayment or extinguishment costs; (2) settlement of zero-coupon debt instruments or other debt instruments with coupon rates that are insignificant in relation to the effective interest rate of the borrowing; (3) contingent consideration payments made after a business combination; (4) proceeds from the settlement of insurance claims; (5) proceeds from the settlement of corporate-owned life insurance; (6) distributions received from equity method investees; and (7) beneficial interests in securitization transactions. Additionally, the update clarifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early adoption permitted. The Company expects to adopt this standards update, as required, beginning with the first quarter of 2018. The Company is currently evaluating the effect of the amendments on our consolidated financial statements and related disclosures.

Note 3. Acquisitions and Divestitures

Lynden Arrangement

On May 18, 2016, the Company acquired Lynden Energy Corp. ("Lynden") in an all-stock transaction through an arrangement (the "Lynden Arrangement") instead of a merger because Lynden is incorporated in British Columbia, Canada. The Company acquired all outstanding shares of Lynden's common stock, through a newly formed subsidiary, with Lynden surviving as a wholly-owned subsidiary of the Company, issuing 3,700,279 shares of its common stock, $0.001 par value per share (the "Common Stock"), to the holders of the common stock of Lynden. The Lynden Arrangement was accounted for as a business combination in accordance with FASB ASC Topic 805, *Business Combinations*, which, among other things, requires the assets acquired and liabilities assumed to be measured and recorded at their fair values as of the acquisition date.

An allocation of the purchase price was prepared using, among other things, an independent fair market valuation. The following is still preliminary with respect to final tax amounts and includes the use of estimates based on information that was available to management at the time these consolidated financial statements were prepared. We expect the purchase price allocation to be finalized in the first quarter of 2017. Based on our ongoing review of preliminary tax amounts, we adjusted the deferred tax liability recorded as a result of the acquisition and a corresponding change to goodwill in the fourth quarter of 2016.

The following table summarizes the consideration transferred, fair value of assets acquired and liabilities assumed and resulting goodwill (*in thousands, except share and share price amount*):

Consideration:		
Shares of Earthstone common stock issued in the Arrangement		3,700,279
Closing price of Earthstone common stock as of May 18, 2016	$	12.35
Total consideration to Lynden shareholders	$	45,698
Fair Value of Liabilities Assumed:		
Credit facility (4)	$	36,597
Current liabilities		1,915
Deferred tax liability (1)		15,157
Asset retirement obligations		250
Total consideration plus liabilities assumed	$	99,617
Fair Value of Assets Acquired:		
Cash and cash equivalents (4)	$	5,263
Current assets		2,018
Proved oil and gas properties (2)(3)		48,116
Unproved oil and gas properties		26,600
Amount attributable to assets acquired	$	81,997
Goodwill (5)	$	17,620

(1) This amount represents the difference between the recorded book value and the tax basis of the oil and natural gas properties as of the date of the closing of the Lynden Arrangement, tax-effected using a tax rate of approximately 34.5%.

(2) The weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $64.73 per barrel of oil, $3.68 per Mcf of natural gas and $19.34 per barrel of oil equivalent for natural gas liquids, after adjustments for transportation fees and regional price differentials.

(3) The market assumptions as to the future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of the future development and operating costs, projecting of future rates of production, expected recovery rate and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs; see *Note 4. Fair Value Measurements,* below.

(4) Concurrent with closing the Lynden Arrangement, the Company paid off the outstanding balance of $36.6 million on the Lynden credit facility. The settlement of the debt and the cash acquired is equal to the $31.3 million net cash outflow associated with the Lynden Arrangement.

(5) Goodwill was determined to be the excess consideration exchanged over the fair value of the net assets of Lynden on May 18, 2016. The goodwill resulted from the expected synergies of the management team and balance sheet of the Company combined with the key assets acquired in the Midland Basin area. The goodwill recognized will not be deductible for tax purposes.

The following unaudited supplemental pro forma results of operations present consolidated information a ssuming the Lynden Arrangement had been completed as of January 1, 2014. The unaudited supplemental pro forma financial information was derived from the historical consolidated and combined statements of operations for the Company and Lynden and adjusted to include: (i) depletion expense applied to the adjusted basis of the properties acquired, (ii) accretion expense associated with the asset retirement obligations recorded using the Company's assumptions about the future liabilities and (iii) interest expense based on the combined debt of the Company post-acquisition. These unaudited 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. Future results may vary significantly from the results reflected in this unaudited pro forma financial information (*in thousands, except per share amounts*).

	Years ended December 31,		
	2016	2015	2014
		(Unaudited)	
Revenue	$ 47,679	$ 62,817	$ 112,370
(Loss) income before taxes	$ (53,510)	$ (148,609)	$ 32,912
Net (loss) income available to Earthstone common stockholders	$ (54,744)	$ (122,598)	$ 19,518
Pro Forma net (loss) income per common share:			
Basic	$ (2.73)	$ (6.99)	$ 1.11
Diluted	$ (2.73)	$ (6.99)	$ 1.11

Earthstone Energy Reverse Acquisition

On December 19, 2014, the Company acquired three operating subsidiaries of OVR, which included producing assets, undeveloped acreage and cash, in exchange for shares of Common Stock (the "Exchange"), which resulted in a change of control of the Company. Pursuant to the Exchange Agreement, OVR contributed to Earthstone the membership interests of its three subsidiaries, Earthstone Operating, LLC (formerly Oak Valley Operating, LLC ("OVO")), EF Non-Op, LLC ("EF Non-Op") and Sabine River Energy, LLC ("Sabine"), each a Texas limited liability company (collectively "Oak Valley"). OVR received approximately 9.124 million shares of the Common Stock of the Company. The Exchange resulted in a change of control of the Company. The Exchange was recorded in accordance with FASB ASC Topic 805 as a reverse acquisition whereby Oak Valley was considered the acquirer for accounting purposes although Earthstone was the acquirer for legal purposes. ASC 805 also requires that, among other things, assets acquired and liabilities assumed be measured at their acquisition date fair values. The results of operations from Earthstone's legacy assets are reflected in the Company's Consolidated Statement of Operations beginning December 19, 2014.

An allocation of the purchase price was prepared using, among other things, the December 31, 2014 reserve report prepared by Cawley, Gillespie and Associates, Inc. ("CG&A"), adjusted by the Company's reserve engineering staff back to the December 19, 2014 acquisition date.

The following table summarizes the consideration paid to acquire the legacy Earthstone net assets and the estimated values of those net assets (*in thousands, except share and share price amounts*):

Shares of Common Stock issued as consideration		1,753,388
Closing price of Common Stock as of December 19, 2014	$	19.08
Total purchase price	$	33,455
Estimated Fair Value of Liabilities Assumed:		
Current liabilities	$	7,631
Long-term debt		7,000
Deferred tax liability (1)		2,880
Asset retirement obligation		1,035
Amount attributable to liabilities assumed		18,546
Total purchase price plus liabilities assumed	$	52,001
Estimated Fair Value of Assets Acquired:		
Cash (2)	$	2,920
Other current assets		3,466
Proved oil and natural gas properties (3) (4)		21,813
Unproved oil and natural gas properties		5,524
Other non-current assets		746
Amount attributable to assets acquired	$	34,469
Goodwill (5)	$	17,532

(1) This amount represents the difference between the recorded book value and the tax basis of the oil and natural gas properties as of the date of the closing of the Exchange, tax-effected using a tax rate of approximately 35%.

(2) Net cash flow related to the Exchange was an outflow of $4.2 million which consisted of the $7.1 million repayment of long-term debt (plus accrued interest) less the cash acquired of $2.9 million.

(3) The weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $51.62 per barrel of oil and $4.58 per Mcf of natural gas after adjustments for transportation fees and regional price differentials.

(4) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see *Note 4. Fair Value Measurements*.

(5) Goodwill was determined to be the excess consideration exchanged over the fair value of the Company's net assets on December 19, 2014. In 2016, due to the commodity price environment, the Company determined that the amount recorded was no longer recoverable and recognized a full impairment charge to Goodwill of $17.5 million in the Consolidated Statement of Operations. See *Note 7.Goodwill*.

2014 Eagle Ford Acquisition Properties

On December 19, 2014, immediately following the Exchange, Flatonia Energy, LLC ("Flatonia"), Parallel Resource Partners, LLC ("Parallel"), and Sabine, closed a contribution agreement (the "Flatonia Contribution Agreement") by and among the Company, OVR, Sabine, OVO, Parallel, and Flatonia, whereby Parallel contributed 28.57% of the oil and natural gas property interests held by Flatonia, a wholly owned subsidiary of Parallel, in exchange for approximately 2.957 million shares of Common Stock. The assets subject to the Flatonia Contribution Agreement were oil and natural gas property interests in producing wells and acreage in the Eagle Ford trend of Texas (the "2014 Eagle Ford Acquisition Properties"). One of the subsidiaries included in the Exchange is the operator of the 2014 Eagle Ford Acquisition Properties. The only relationship that Flatonia or Parallel had with this subsidiary or the Company prior to the transaction was that the subsidiary is the operator of the 2014 Eagle Ford Acquisition Properties. The Flatonia Contribution Agreement was accounted for as a business combination in accordance ASC 805 which, among other things, requires the assets acquired and liabilities assumed to be measured and recorded at their fair values as of the acquisition date.

An allocation of the purchase price was prepared using, the D ecember 31, 2014 reserve report prepared by CG&A that was adjusted by the Company's reserve engineering staff back to December 19, 2014.

The following table summarizes the consideration paid to acquire the 2014 Eagle Ford Acquisition Properties and the estimated values of those net assets (*in thousands, except share and share price amounts*):

Shares of Common Stock issued as consideration in the Contribution		2,957,288
Closing price of Common Stock as of December 19, 2014	$	19.08
Total purchase price	$	56,425
Estimated Fair Value of Liabilities Assumed:		
Deferred tax liability (1)	$	1,547
Asset retirement obligation		173
Amount attributable to liabilities assumed		1,720
Total purchase price plus liabilities assumed	$	58,145
Estimated Fair Value of Assets Acquired:		
Proved oil and natural gas properties (2) (3)	$	34,745
Unproved oil and natural gas properties		21,853
Amount attributable to assets acquired	$	56,598
Goodwill (4)	$	1,547

(1) This amount represents the difference between the recorded book value and the tax basis of the oil and natural gas properties as of the date of the closing of the Flatonia Contribution Agreement, tax-effected using a tax rate of approximately 34%.

(2) The weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $56.36 per barrel of oil and $3.36 per Mcf of natural gas after adjustments for transportation fees and regional price differentials.

(3) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see *Note 4. Fair Value Measurements*.

(4) Goodwill was determined as the excess consideration exchanged over the fair value of the 2014 Eagle Ford Acquisition Properties on December 19, 2014. In 2015, due to the commodity price environment, the Company determined that the goodwill balance was not recoverable and therefore fully impaired it, recording a goodwill impairment charge of $1.5 million. See *Note 7.Goodwill*.

Other Acquisitions

In June 2015, the Company acquired a 50% operated working interests in approximately 1,000 gross acres in southern Gonzales County, Texas. The acreage, acquired for future Eagle Ford development, is 100% held-by-production by two gross Austin Chalk wells with gross production of 44 barrels of oil equivalent per day as of the time of acquisition.

Also during June 2015, the Company acquired 400 gross acres in northern Karnes County, Texas, which is adjacent to the 1,000 gross acres in southern Gonzales County, Texas. Subsequent trades in Karnes County reduced the gross acreage from 400 to 350 gross acres (117 net acres).

The following table summarizes the consideration paid to acquire the properties and the estimated fair values of the assets acquired and liabilities assumed *(in thousands)*:

Purchase price	$	4,066
Estimated fair value of assets acquired:		
Proved oil and natural gas properties	$	588
Unproved oil and natural gas properties		3,496
Total assets acquired	$	4,084
Estimated fair value of liabilities assumed:		
Asset retirement obligations	$	13
Other liabilities		5
Total liabilities assumed	$	18
Consideration paid	$	4,066

Additionally, in June 2015, the Company acquired additional acreage and working interest in wells located within existing Bakken spacing units primarily located in the Banks Field of McKenzie County, North Dakota, for $1.4 million plus purchase price adjustments of $2.0 million for the revenues, net of production taxes and operating expenses and capital costs incurred for the existing wells. The acquisition included 164 net acres which allowed the Company to increase its working interest in approximately 41 producing wells and 21 wells that were in the drilling and completion phase.

In August 2015, the Company acquired a 33% working interest in approximately 1,650 gross acres, in southern Gonzales County, Texas for $3.3 million.

Divestitures

In April 2015, the Company sold its Louisiana properties located primarily in DeSoto and Caddo Parishes, Louisiana, for cash consideration of $3.4 million. The Company recorded a gain of $1.6 million on the sale. The effective date of the transaction was March 1, 2015.

Note 4. Fair Value Measurements

FASB ASC Topic 820, defines fair value 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. ASC 820 provides a framework for measuring fair value, establishes a three level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date and requires consideration of the counterparty's creditworthiness when valuing certain assets.

The three-level fair value hierarchy for disclosure of fair value measurements defined by ASC 820 is as follows:

Level 1 – Unadjusted, quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is defined as a market where transactions for the financial instrument occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Inputs, other than quoted prices within Level 1, that are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level 3 – Prices or valuations that require unobservable inputs that are both significant to the fair value measurement and unobservable. Valuation under Level 3 generally involves a significant degree of judgment from management.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instrument's complexity. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level. There were no transfers between fair value hierarchy levels for the year ended December 31, 2016.

Fair Value on a Recurring Basis

Derivative financial instruments are carried at fair value and measured on a recurring basis. The derivative financial instruments consist of swaps for crude oil and natural gas. The Company's swaps are valued based on a discounted future cash flow model. The primary input for the model is published forward commodity price curves. The swaps are also designated as Level 2 within the valuation hierarchy.

The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of the Company's nonperformance risk. These measurements were not material to the consolidated financial statements.

The following table summarizes the fair value of the Company's financial assets and liabilities, by level within the fair-value hierarchy *(in thousands)*:

December 31, 2016	Level 1	Level 2	Level 3	Total
Financial liabilities				
Derivative liability	$ —	$ 4,595	$ —	$ 4,595
Derivative liability	—	1,575	—	1,575
Total financial liabilities	$ —	$ 6,170	$ —	$ 6,170
December 31, 2015				
Financial assets				
Derivative asset	$ —	$ 3,694	$ —	$ 3,694
Total financial assets	$ —	$ 3,694	$ —	$ 3,694

Other financial instruments include cash, accounts receivable and payable, and revenue royalties. The carrying amount of these instruments approximates fair value because of their short-term nature. The Company's long-term debt obligation bears interest at floating market rates, therefore carrying amounts and fair value are approximately equal.

Fair Value on a Nonrecurring Basis

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including oil and gas properties and goodwill. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances.

Property Impairments

Oil and gas properties are measured at fair value on a nonrecurring basis. The impairment charge reduces the carrying values of oil and gas properties' to their estimated fair values. These fair value measurements are classified as Level 3 measurements and include many unobservable inputs. Fair value is calculated as the estimated discounted future net cash flows attributable to the assets. The Company's primary assumptions in preparing the estimated discounted future net cash flows to be recovered from oil and gas properties are based on (i) proved reserves, (ii) forward commodity prices and assumptions as to costs and expenses, and (iii) the estimated discount rate that would be used by potential purchasers to determine the fair value of the assets. See *Note 6. Oil and Natural Gas Properties*.

Goodwill

Goodwill represents the excess of the purchase price of assets acquired over the fair value of those assets and is tested for impairment annually, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors. See *Note 7. Goodwill.*

Business Combinations

The Company records the identifiable assets acquired and liabilities assumed at fair value at the date of acquisition on a nonrecurring basis. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on NYMEX commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. The future oil and natural gas pricing used in the valuation is a Level 2 assumption. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the determination of fair value of the acquisition include the Company's estimate operating and development costs, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. The Company's acquisitions are discussed in *Note 3 Acquisitions and Divestitures*.

Asset Retirement Obligations

The asset retirement obligation estimates are derived from historical costs and management's expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. The significant inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, well life, inflation and credit-adjusted risk free rate. See *Note 12 Asset Retirement Obligations* for a reconciliation of the beginning and ending balances of the liability for the Company's asset retirement obligations.

Note 5. Derivative Financial Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are utilized to economically hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company follows FASB ASC Topic 815, *Derivatives and Hedging,* to account for its derivative financial instruments. The Company does not enter into derivative contracts for speculative trading purposes. It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive. The Company did not post collateral under any of these contracts.

The Company's crude oil and natural gas derivative positions consist of swaps. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. The Company has elected to not designate any of its derivative contracts for hedge accounting purposes. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *(Loss) gain on derivative contracts, net* on the Consolidated Statements of Operations. All derivative contracts are recorded at fair market value in the Consolidated Balance Sheets as assets or liabilities.

With an individual derivative counterparty, the Company may have multiple hedge positions that expire at various points in the future and result in fair value asset and liability positions. At the end of each reporting period, those positions are offset to a single fair value asset or liability for each commodity by counterparty, and the netted balance is reflected in the Consolidated Balance Sheets as an asset or a liability.

The Company nets its derivative instrument fair value amounts executed with each counterparty pursuant to an International Swap Dealers Association Master Agreement ("ISDA"), which provides for net settlement over the term of the contract. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency

The Company had the following open crude oil and natural gas derivative contracts as of December 31, 2016:

	Price Swaps		
Period	Commodity	Volume (Bbls / MMBtu)	Weighted Average Price ($/Bbl / $/MMBtu)
Q1 - Q4 2017	Crude Oil	600,000	$ 50.38
Q1 - Q4 2018	Crude Oil	270,000	$ 50.70
Q1 - Q4 2017	Natural Gas	1,740,000	$ 2.997
Q1 - Q4 2018	Natural Gas	600,000	$ 2.907

The following table summarizes the location and fair value amounts of all derivative instruments in the Consolidated Balance Sheets as well as the gross recognized derivative assets, liabilities, and amounts offset in the Consolidated Balance Sheets *(in thousands)*:

		December 31, 2016			December 31, 2015		
Derivatives not designated as hedging contracts under ASC Topic 815	Balance Sheet Location	Gross Recognized Assets / Liabilities	Gross Amounts Offset	Net Recognized Assets / Liabilities	Gross Recognized Assets / Liabilities	Gross Amounts Offset	Net Recognized Assets / Liabilities
Commodity contracts	Derivative asset	$ —	$ —	$ —	$ 3,694	$ —	$ 3,694
Commodity contracts	Derivative liability	$ 4,595	$ —	$ 4,595	$ —	$ —	$ —
Commodity contracts	Derivative liability	$ 1,575	$ —	$ 1,575	$ —	$ —	$ —

The follow table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivatives instruments in the Company's Consolidated Statements of Operations *(in thousands)*:

		Years Ended December 31,		
Derivatives not designated as hedging contracts under ASC Topic 815	Statement of Operations Location	2016	2015	2014
Total (loss) gain on commodity contracts	(Loss) gain on derivative contracts, net	$ (9,863)	$ 125	$ 3,614
Cash settlements on commodity contracts	(Loss) gain on derivative contracts, net	3,225	6,306	778
(Loss) gain on commodity contracts, net		$ (6,638)	$ 6,431	$ 4,392

Note 6. Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method, costs to acquire oil and gas properties, drill and equip exploratory wells that find proved reserves, and drill and equip development wells are capitalized. Exploration costs, including unsuccessful exploratory wells and geological and geophysical costs, are charged to operations as incurred. Upon sale or retirement of oil and gas properties, the costs and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss is recognized.

Costs incurred to maintain wells and related equipment, lease and well operating costs, and other exploration costs are charged to expense as incurred. Gains and losses arising from the sale of properties are included in operating income (loss) in the Consolidated Statements of Operations.

The Company's lease acquisition costs and development costs of proved oil and gas properties are amortized using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively. Depletion expense for oil and gas producing property and related equipment was $25.4 million, $30.7 million, and $18.1 million, for the years ended December 31, 2016, 2015, and 2014, respectively.

Proved Properties

The Company reviews its proved oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying values of such properties, such as a negative revision of reserves estimates or sustained decrease in commodity prices. We estimate future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying amount, then the carrying amount is written down to its estimated fair value.

Unproved Properties

Unproved properties consist of costs incurred to acquire undeveloped leases as well as the cost to acquire unproved reserves. Undeveloped lease costs and unproved reserve acquisition costs are capitalized. Unproved oil and gas leases are generally for a primary term of three to five years. In most cases, the term of the unproved leases can be extended by paying delay rentals, meeting contractual drilling obligations, or by the pre sence of producing wells on the leases. Unproved costs related to successful exploratory drilling are reclassified to proved properties and depleted on a units-of-production basis.

The Company reviews its unproved properties periodically for impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current exploration and development plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property

The Company had the following non-cash asset impairment charges to its oil and natural gas properties for the years ended December 31, 2016, 2015 and 2014 (*in thousands*):

	Years Ended December 31,		
	2016	2015	2014
Proved property	$ 2,873	$ 93,984	$ 16,903
Unproved property	3,878	42,555	2,456
Total	$ 6,751	$ 136,539	$ 19,359

Accumulated impairments to proved and unproved oil and natural gas properties as of December 31, 2016 and 2015, were $162.7 million and $155.9 million, respectively.

Note 7. Goodwill

Goodwill represents the excess of the purchase price of assets acquired over the fair value of those assets and is tested for impairment annually, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors.

The Company had the following non-cash impairment charges to its goodwill for the years ended December 31, 2016 and 2015 (*in thousands*):

	Years Ended December 31,	
	2016	2015
Impairment expense - goodwill	$ 17,532	$ 1,547

The Company did not have any non-cash impairment charges to its goodwill for the year ended December 31, 2014.

Accumulated impairments to Goodwill as of December 31, 2016 and 2015, were $19.1 million and $1.5 million, respectively.

Note 8. 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 in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of Loss per common share is as follows:

	Years Ended December 31,		
(In thousands, except per share amounts)	2016	2015	2014
Net loss	$ (54,541)	$ (116,655)	$ (28,834)
Net loss per common share:			
Basic	$ (2.92)	$ (8.43)	$ (3.11)
Diluted	$ (2.92)	$ (8.43)	$ (3.11)
Weighted average common shares outstanding			
Basic	18,651,582	13,835,128	9,279,324
Add potentially dilutive securities:			
Nonvested restricted stock units	—	—	—
Diluted weighted average common shares outstanding	18,651,582	13,835,128	9,279,324

For the year ended December 31, 2016, the Company excluded 52,844 shares for the dilutive effect of restricted stock units in calculating diluted earnings per share as the effect was anti-dilutive due to the net loss incurred this period. For the years ended December 31, 2015 and 2014, there were no restricted stock units issued or outstanding under the Company's long-term incentive plan.

Note 9. Common Stock

At December 31, 2016 and 2015, there were 22,289,177 and 13,835,128 shares of Common Stock issued, respectively, both including 15,357 shares of treasury stock held by the Company.

During the year ended December 31, 2016, there were the following changes to the Common Stock:

- On May 18, 2016, the Company acquired Lynden in an all-stock transaction issuing 3,700,279 shares of Common Stock, valued at $45.7 million on that date, to the holders of the common stock of Lynden. For additional information, see *Note 3. Acquisitions and Divestitures*.
- On June 21, 2016, the Company completed a public offering of 4,753,770 shares of Common Stock at an issue price of $10.50 per share. The Company received net proceeds from this offering of $47.1 million, after deducting underwriters' fees and offering expenses of $2.7 million. See *Note 1. Organization and Basis of Presentation*.

During the year ended December 31, 2015, there were no changes to the Common Stock.

During the year ended December 31, 2014, there were the following changes to the Common Stock:

- On December 19, 2014, pursuant to the Exchange Agreement, the Company issued 9,124,452 shares of Common Stock to OVR in exchange for the outstanding membership interests of OVR's three subsidiaries and 1,753,388, provided as consideration, represented Earthstone's legacy common stock, of which 15,357 shares represented Earthstone's legacy treasury stock. For additional information, see *Note 1. Organization and Basis of Presentation*.
- Immediately following the exchange, the Company, through its wholly owned subsidiary, Sabine, acquired an additional 20% undivided ownership interest in certain crude oil and natural gas properties located in Fayette and Gonzales Counties, Texas, in exchange for the issuance of approximately 2,957,288 shares of Common Stock. For additional information, see *Note 1. Organization and Basis of Presentation.*

Note 10. Stock Based Compensation

The Company's amended 2014 Long-term Incentive Plan (the "2014 Plan") allows, among other things, for the grant of restricted stock units ("RSUs"). RSUs do not pay dividends or have voting rights prior to vesting. The Company determines the fair value of granted RSUs based on the market price of the Common Stock of the Company on the date of the grant. Compensation expense is for granted RSUs is recognized on a straight-line basis over the vesting and is net of forfeitures, as incurred.

During the year ended December 31, 2016, the Company granted 754,500 RSU's to employees of the Company and 27,000 RSUs to members of its Board of Directors (the "Awards"). The weighted average grant date fair value of the Awards was $12.53 per share. The future compensation cost of the Awards at December 31, 2016 is $6.5 million which will be amortized over the remaining vesting period. The weighted average remaining useful life of the future compensation cost is 0.74 years. Stock-based compensation for the year ended December 31, 2016 recorded in the Consolidated Statements of Operations was $3.3 million. There was no stock-based compensation for the years ended December 31, 2015 and 2014.

Note 11. Long-Term Debt

Credit Facility

In December, 2014, the Company entered into a credit agreement providing for a $500.0 million four-year senior secured revolving credit facility (the "Credit Agreement"). At December 31, 2016, borrowing base under the Credit Agreement was $80.0 million and is subject to redetermination on May 1 and November 1 each year, as well as other elective borrowing base redeterminations. As of December 31, 2016, outstanding borrowings under the Credit Agreement bear interest at a rate elected by the Company that is equal to a base rate (which is equal to the greater of the prime rate, the Federal Funds effective rate plus 0.50%, and 1-month LIBOR plus 1.00%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 1.25% to 2.25% for base rate loans and from 2.25% to 3.25% for LIBOR loans, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. The Company is also required to pay customary letter of credit fees. Principal amounts outstanding under the Credit Agreement are due and payable in full at maturity on December 19, 2018. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of the Company's assets.

As of December 31, 2016, the Company had an $80.0 million borrowing base, of which $10.0 million of debt was outstanding, bearing an interest rate of 2.867%, as well as a $0.2 million letters of credit outstanding related to our office lease, resulting in $69.8 million of borrowing base availability under the Credit Agreement.

The Credit Agreement contains a number of customary covenants that, among other things, restrict, subject to certain exceptions, the Company's ability to incur additional indebtedness, create liens on asset, pay dividends, and repurchase its capital stock. In addition, the Company is required to maintain certain financial ratios, including a minimum modified current ratio which includes the available borrowing base of 1.0 to 1.0 and a maximum annualized quarterly leverage ratio of 4.0 to 1.0. The Company is also required to submit an audited annual report 120 days after the end of each fiscal period. As of December 31, 2016, the Company was in compliance with these covenants under the Credit Agreement.

Promissory Note

In July 2016, the Company issued a $5.1 million unsecured promissory note (the "Note") to a drilling rig contractor in settlement of rig idle charges and a contract termination fee. These expenses were recognized in the Company's Consolidated Statement of Operations in the line item *Rig idle and contract termination expense*. The Note is payable in monthly installments over a three-year period maturing in July 2019, bearing an annualized interest rate of 8.0% for the first 12 months, 10.0% for the subsequent 12 months, and 12.0% for the last 12 months, with no prepayment penalty. Interest expense is recognized using the effective interest method of approximately 9.1% over the life of the note. As of December 31, 2016, the Company has $4.3 million outstanding under the note with $1.6 million included in the current portion of long-term debt.

The following table below summarizes long term debt (*in thousands*):

	December 31, 2016	December 31, 2015
Borrowings under Credit Agreement	$ 10,000	$ 11,191
Promissory note	4,297	—
Total debt	14,297	11,191
Less: Current portion of long-term debt	(1,604)	—
Long-term debt	$ 12,693	$ 11,191

For the year ended December 31, 2016, we borrowed $36.6 million and made payments of $37.8 million under the Credit Agreement. For the year ended December 31, 2015, we had no borrowings or payments under the Credit Agreement. For the year ended December 31, 2014, we borrowed $11.2 million and made payments of $10.8 million under the Credit Agreement.

For the years ended December 31, 2016, 2015 and 2014, interest on borrowings under the Credit Agreement averaged 2.94%, 1.68% and 2.16% per annum, respectively. Interest expense for the years ended December 31, 2016, 2015 and 2014, includes amortization of deferred financing costs of $0.3 million, $0.3 million, and $0.2 million, respectively. The Company capitalized $0.1 million, $0.1 million, and $0.6 million for the years ended December 31, 2016, 2015 and 2014, respectively, of deferred financing costs associated with borrowing under the Credit Agreement. These costs are included in *Other noncurrent assets* on the Company's Consolidated Balance Sheets. The Company's policy is to capitalize the financing costs associated with the Credit Agreement and amortize those costs on a straight-line basis over the term of the Credit Agreement.

Note 12. Asset Retirement Obligations

The Company has asset retirement obligations associated with the future plugging and abandonment of oil and gas properties and related facilities. Revisions to the liability typically occur due to changes in the estimated abandonment costs, well economic lives, and the discount rate.

The following table summarizes the Company's asset retirement obligation transactions recorded during the years ended December 31, 2016 and 2015 *(in thousands)*:

	2016	2015
Beginning asset retirement obligations	$ 5,075	$ 6,078
Liabilities incurred	165	126
Liabilities settled	(15)	(108)
Accretion expense	551	550
Acquisitions (1)	250	—
Purchase price adjustment (2)	—	(1,192)
Property dispositions	—	(403)
Revision of estimates	(13)	24
Ending asset retirement obligations	$ 6,013	$ 5,075

(1) See *Note 3 Acquisitions and Divestitures* for additional information on the Company's acquisition activities.

(2) The Company recorded a purchase price adjustment in 2015 related to the Exchange. The adjustment decreased the allocation of asset retirement obligations due to adjusting the estimates of liabilities assumed to match the Company's methodology. See *Note 3 Acquisition and Divestitures*.

Note 13. Related Party Transactions

FASB ASC Topic 850*, Related Party Disclosures*, requires that information about transactions with related parties that would make a difference in decision making shall be disclosed so that users of the financial statements can evaluate their significance.

Flatonia, which owns approximately 13.3% of our common stock, is a party to a joint operating agreement (the "Operating Agreement") with OVO. This agreement was entered into prior to the closing of the Flatonia Contribution Agreement on December

19, 2014 under which PRP acquired shares of the Common Stock of the Company. The operating agreement covers certain jointly owned oil and gas properties located in the Eagle Ford trend in Texas. In connection with the Operating Agreement, we made payments to Flatonia of $26.6 million and $33.9 million and received $21.7 million and $66.7 million in the years ended December 31, 2016 and 2015, respectively. Amounts receivable from Flatonia in connection with the Operating Agreement were $1.5 million and $3.9 million at December 31, 2016 and 2015, respectively. Amounts payable to Flatonia in connection with the Operating Agreement were $3.1 million and $16.4 million at December 31, 2016 and 2015, respectively.

Note 14. Commitments and Contingencies

Contractual Commitments

Future minimum contractual commitments as of December 31, 2016 under non-cancelable agreements having remaining terms in excess of one year are as follows:

	2017	2018	2019	2020	2021	Thereafter
Gas contract	$ 1,643	$ 1,643	$ 1,643	$ 1,647	$ 680	$ —
Office leases	738	661	627	—	—	—
Total	$ 2,381	$ 2,304	$ 2,270	$ 1,647	$ 680	$ —

The Company has a non-cancelable fixed cost agreement of $1.6 million per year through 2021 to reserve pipeline capacity of 10,000 MMBtu per day for gathering and processing related to certain Eagle Ford assets in south Texas through 2021.Additionally, the Company leases corporate office space in The Woodlands, Texas and Denver, Colorado. Rent expense was approximately $0.8 million, $0.8 million, and $0.4 million for the years ended December 31, 2016, 2015, and 2014, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2016 are shown in the table above.

Environmental

The Company's operations are subject to risks normally associated with the drilling, completion and production of oil and gas, including blowouts, fires, and environmental risks such as oil spills or gas leaks that could expose the Company to liabilities associated with these risks.

In the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of prior environmental safeguards, if any, that were taken at the time such wells were drilled or during such time the wells were operated. The Company maintains comprehensive insurance coverage that it believes is adequate to mitigate the risk of any adverse financial effects associated with these risks.

However, should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could still fall upon the Company. No claim has been made, nor is the Company aware of any liability which the Company may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations relating thereto except for the matter discussed above.

Legal

From time to time, the Company and its subsidiaries may be involved in various legal proceedings and claims in the ordinary course of business. In July 2015, EF Non-Op, LLC, a subsidiary of the Company, filed suit in the 125th Judicial District Court of Harris County, Texas against the operator of its properties in LaSalle County, Texas. In the case *EF Non-Op, LLC vs. BHP Billiton Petroleum Properties (N.A.), LP (F/K/A Petrohawk Properties, LP),* the Company claims the operator has breached the applicable joint operating agreements in numerous ways, including, but not limited to, improper authorization for expenditure requests, improper and imprudent operations, misrepresentation of charges and excessive billings, as well as refusal to provide requested information. The Company also claims damages from negligent representation and fraud. The Company is seeking all relief to which it is entitled, including consequential damages and attorneys' fees. With respect to a portion of the litigation associated with nine non-operated gas wells that were drilled in 2014 and placed on production in the first half of 2015, BHP Billiton in early 2016 elected to deem the Company as a non-consenting working interest owner regarding costs associated with the drilling, completing and operating of these nine wells, as BHP's sole and exclusive remedy. The Company has accepted this "non-consent" status. The litigation is continuing with respect to other disputes. The outcome of remaining disputes in this proceeding is uncertain, and while the Company is confident in its position, any potential monetary recovery to the Company cannot be estimated at this time.

Note 15. Income Taxes

The following table shows the components of the Company's income tax provision for the years ended December 31, 2016, 2015 and 2014 (*in thousands*):

	Years Ended December 31,		
	2016	2015	2014
Current:			
Federal	$ —	$ —	$ —
State	—	91	—
Total current	—	91	—
Deferred:			
Federal	515	(26,214)	21,803
State	13	(319)	302
Total deferred	528	(26,533)	22,105
Total income tax provision (benefit)	$ 528	$ (26,442)	$ 22,105

Effective Tax Rate

Our corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns and one Canadian income tax return resulting from the Lynden Arrangement that includes Lynden USA, Inc. ("Lynden US"), Earthstone Energy, Inc. ("Earthstone"), and Lynden Energy Corp. (the Canadian entity), As such, taxable income of Earthstone cannot be offset by tax attributes, including net operating losses, of Lynden US, nor can taxable income of Lynden US, Inc.be offset by tax attributes of Earthstone.

A reconciliation of the effective tax rate to the statutory rate for the year ended December 31, 2016 rate is as follows (*in thousands, except percentages*):

	U.S.	Canada	Total
Net loss before income taxes	$ (54,032)	$ 19	$ (54,013)
Statutory rate	34%	26%	
Tax benefit computed at statutory rate	(18,370)	5	(18,365)
Non-deductible impairment of goodwill	5,961	—	5,961
Non-deductible transaction costs	878	—	878
Non-deductible general and administrative expenses	5	—	5
Return to accrual	15	—	15
State income taxes, net of Federal benefit	(128)	—	(128)
Valuation allowance	12,167	(5)	12,162
Total income tax expense	$ 528	$ —	$ 528
Effective tax rate	-1.0%	0.0%	-1.0%

During the year ended December 31, 2016, we recorded income tax expense related to Lynden of $0.5 million. For the remainder of the Company, we recorded an income tax benefit of $12.2 million as a result of the related pre-tax net losses which were offset by a full valuation allowance, as future realization of the related deferred tax asset cannot be assured.

A reconciliation of the effective tax rate to the statutory rate for the years ended December 31, 2015 and 2014 rates is as follows (*in thousands, except percentages*):

	Years Ended December 31,	
	2015	2014
Net loss before income taxes	$ (143,097)	$ (6,729)
Tax benefit computed at Federal statutory rate	(48,653)	(2,288)
Non-taxable Oak Valley income prior to merger	—	(4,142)
Deferred income tax arising from change in tax status of Oak Valley	—	28,347
Non-deductible general and administrative expenses	534	—
Return to accrual	(1,398)	—
State income taxes, net of Federal benefit	(743)	188
Valuation allowance	23,818	—
Total income tax (benefit) expense	$ (26,442)	$ 22,105
Effective tax rate	18.5%	-328.5%

The Company's effective tax rate for the year ended December 31, 2015, is approximately 18.5% which is less than the U.S. Federal statutory tax rate primarily due to the increase in valuation allowance in 2015. The impairments recorded by the Company during 2015 reduced the book value of its properties below the tax basis; thereby, giving rise to a significant deferred tax asset associated with its oil and gas properties and putting the Company in an overall net deferred tax asset position prior to any realization assessment. The realizability of the Company's deferred tax assets is not more likely-than-not, therefore the Company recorded a valuation allowance to reduce its overall net deferred tax asset portion to zero.

Deferred Tax Assets And Liabilities

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities at December 31, 2016 and 2015 are as follows (*in thousands*):

	December 31,	
	2016	2015
Deferred noncurrent income tax assets (liabilities):		
Office and other equipment	(48)	(253)
Oil & gas properties	7,428	23,177
Asset retirement obligation	2,042	1,788
Basis difference in subsidiary obligation	(4,226)	—
Intangible assets	36	(7)
Unrealized derivative loss (gain)	2,145	(1,284)
Stock-based compensation	1,148	—
Federal net operating loss carryforward	15,109	339
Other	186	59
Net deferred noncurrent tax assets	23,820	23,819
Valuation allowance	(39,596)	(23,819)
Net deferred tax (liability) asset	$ (15,776)	$ —

As of December 31, 2016, the Company has a valuation allowance recorded against its deferred tax assets of $39.6 million which is in excess of its Net deferred noncurrent tax assets of $23.8 million, as presented above. The Company's corporate organizational structure requires the filing of two separate consolidated U.S. Federal income tax returns and one Canadian income tax return. As a result, tax attributes of one group cannot be offset by the tax attributes of another. At December 31, 2016, the deferred tax assets and liabilities related to the two U.S. Federal income tax returns and one Canadian income tax return are a $36.0 million deferred tax asset, a $15.8 million deferred tax liability and a $3.6 million deferred tax asset, respectively.

As of December 31, 2016, the Company has estimated U.S. net operating loss carryforwards of $36.4 million, the first expiring in 2034 and the last in 2036, and estimated Canadian net operating loss carryforwards of $10.0 million, the first expiring in 2024 and the last in 2036. The ability to utilize net operating losses and other tax attributes could be subject to a significant limitation if the Company were to undergo an ownership change for the purposes of Section 382 of the US Tax Code ("Sec 382"). The Company has an additional estimated U.S. net operating loss carryforward of $28.0 million limited by Sec 382 resulting from the Lynden Arrangement. The Company continues to evaluate the impact, if any, of potential Sec 382 limitations.

Uncertain Tax Positions

FASB ASC Topic 740, *Income Taxes* (ASC 740) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. As of December 31, 2016, the Company has no material uncertain tax positions. The Company's uncertain tax positions may change in the next twelve months; however, the Company does not expect any possible change to have a significant impact on its results of operations or financial position.

The Company files two federal income tax returns, one Canadian income tax return and various combined and separate filings in several state and local jurisdictions. The Company's practice is to recognize estimated interest and penalties, if any, related to potential underpayment of income taxes as a component of income tax expense in its Consolidated Statement of Operations. As of December 31, 2016, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities.

Note 16. Supplemental Selected Quarterly Financial Data (Unaudited)

(In thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2016				
Oil and gas revenues	$ 6,810	$ 9,777	$ 10,530	$ 15,152
Loss from operations	(6,836)	(6,433)	(4,316)	(28,436)
Net loss	(6,421)	(11,172)	(3,900)	(33,048)
Net loss per common share				
Basic and diluted net loss per share	$ (0.46)	$ (0.69)	$ (0.17)	$ (1.48)
2015				
Oil and gas revenues	$ 11,242	$ 14,958	$ 13,033	$ 8,231
(Loss) income from operations	(2,298)	281	(2,595)	(144,617)
Net (loss) income	(1,114)	(748)	1,718	(116,511)
Net (loss) income per common share				
Basic and diluted net (loss) income per share	$ (0.08)	$ (0.05)	$ 0.12	$ (8.43)

Fourth quarter 2016 loss from operations includes a non-cash impairment charge of $6.8 million to its oil and natural gas properties, as discussed in *Note 6. Oil and Natural Gas Properties* and a non-cash impairment charge of $17.5 million to its goodwill, as discussed in *Note76. Goodwill.* Second quarter 2016 loss from operation includes $5.1 million of expenses related to the termination of a drilling rig, as discussed in *Note 11. Long-Term Debt*.

Fourth quarter 2015 loss from operations includes a non-cash impairment charge of $136.5 million to its oil and natural gas properties, as discussed in *Note 6. Oil and Natural Gas Properties* and a non-cash impairment charge of $1.6 million to its goodwill, as discussed in *Note 7. Goodwill.* Second quarter 2015 income from operations includes a $1.6 million gain on the sale of oil and gas properties, net, as discussed in *Note 3. Acquisitions and Divestitures*.

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (UNAUDITED)

Costs Incurred Related to Oil and Gas Activities

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural gas producing activities. Capitalized costs for proved properties include costs for oil and natural gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion.

The Company's oil and gas activities for 2016, 2015 and 2014 were entirely within the United States of America. Costs incurred in oil and gas producing activities were as follows (*in thousands*):

	Years Ended December 31,		
	2016 (1)	2015	2014
Acquisition cost:			
Proved	$ 48,116	$ 4,508	$ 74,728
Unproved	26,600	10,646	36,236
Exploration costs:			
Exploratory drilling	—	—	—
Geological and geophysical	5	142	111
Development costs	28,577	56,862	75,105
Total additions	$ 103,298	$ 72,158	$ 186,180

(1) Acquisition costs incurred during 2016 consisted entirely of the assets acquired in the Lynden Arrangement described in *Note 3. Acquisitions and Divestitures* of the Notes to Consolidated Financial Statements.

During each of the three years ended December 31, 2016, 2015 and 2014, additions to oil and gas properties of $0.2 million were recorded for estimated costs of future abandonment related to new wells drilled or acquired.

For the years ended December 31, 2016, 2015 and 2014, the Company had no capitalized exploratory well costs.

Capitalized Costs

Capitalized costs, impairment, and depreciation, depletion and amortization relating to our oil and natural gas properties producing activities, all of which are conducted within the continental United States as of December 31, 2016 and 2015 are summarized below (*in thousands*):

	December 31,	
	2016	2015
Oil and gas properties, successful efforts method:		
Proved properties	$ 476,832	$ 394,532
Accumulated impairment to proved properties	(113,760)	(110,888)
Proved properties, net of accumulated impairments	363,072	283,644
Unproved properties	100,612	79,619
Accumulated impairment to Unproved properties	(48,889)	(45,010)
Unproved properties, net of accumulated impairments	51,723	34,609
Total oil and gas properties, net of accumulated impairments	414,795	318,253
Accumulated depreciation, depletion and amortization	(145,393)	(119,920)
Net oil and gas properties	$ 269,402	$ 198,333

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of “proved” and “proved developed” oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves represent estimated quantities expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

The proved reserves estimates shown herein for the years ended December 31, 2016, 2015 and 2014 have been independently prepared by Cawley, Gillespie & Associates, Inc.

The reserve information in these consolidated financial statements represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the Company’s control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgement. As a result, estimates by different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company’s proved reserves will decline as reserves are produced.

The following table illustrates the Company’s estimated net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated. The oil prices as of December 31, 2016, 2015, and 2014 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot prices which equates to $42.75 per barrel, $50.28 per barrel, and $94.99 per barrel, respectively. The natural gas prices as of December 31, 2016, 2015 and 2014 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $2.48 per MMBtu, $2.59 per MMBtu and $4.30 per MMBtu, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials. All prices are held constant in accordance with SEC guidelines.

A summary of the Company's changes in quantities of p roved oil and natural gas reserves for the years ended December 31, 2016, 2015 and 2014 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Balance - December 31, 2013	6,078	24,213	1,318	11,431
Extensions and discoveries	1,909	1,403	221	2,364
Purchases of minerals in place	7,025	6,064	437	8,473
Production	(403)	(2,132)	(124)	(882)
Revision to previous estimates	(806)	9,031	107	806
Balance - December 31, 2014	13,803	38,579	1,959	22,192
Extensions and discoveries	526	828	21	685
Sales of minerals in place	(4)	(8,040)	—	(1,344)
Purchases of minerals in place	1,641	679	208	1,962
Production	(904)	(2,143)	(176)	(1,437)
Revision to previous estimates	(5,701)	(16,565)	(1,022)	(9,484)
Balance - December 31, 2015	9,361	13,338	990	12,574
Extensions and discoveries	345	285	30	423
Purchases of minerals in place	5,548	14,770	2,637	10,647
Production	(878)	(2,171)	(225)	(1,465)
Revision to previous estimates	(7,265)	(5,821)	(1,892)	(10,128)
Balance - December 31, 2016	7,111	20,401	1,540	12,051
Proved developed reserves:				
December 31, 2013	1,307	11,053	557	3,706
December 31, 2014	6,093	16,214	1,005	9,800
December 31, 2015	6,114	10,954	673	8,613
December 31, 2016	6,052	13,545	1,051	9,361
Proved undeveloped reserves:				
December 31, 2013	4,771	13,160	761	7,725
December 31, 2014	7,710	22,365	954	12,392
December 31, 2015	3,247	2,384	317	3,961
December 31, 2016	1,059	6,856	489	2,690

Total proved reserves decreased by 0.5 MMBoe during 2016 which primarily resulted from a 10.1 MMBoe downward reserve revision caused by decreases in the prices used to calculated those reserves (prices used to estimate reserves are included in *Oil and Natural Gas Reserves* above), including the related decrease in volume estimates, along with production of 1.5 MMBoe, which was offset by a 10.6 MMBoe increase in reserves resulting from the purchase of minerals in place through the aforementioned Lynden Arrangement, as well as 0.4 MMBoe resulting from extensions and discoveries.

At December 31, 2016 the Company's estimated proved undeveloped reserves (PUDs) were 2.7 MMBoe, a 1.3 MMBoe net decrease over the previous year's estimate of 4.0 MMBoe. The following details the changes in PUD reserves for 2016 (*in MBoe*):

Proved undeveloped reserves at December 31, 2015	3,961
Conversions to developed	(169)
Extensions and discoveries	293
Purchases	873
Revisions	(2,268)
Proved undeveloped reserves at December 31, 2016	2,690

The change to the PUD reserves was a result of the significant decline in oil and natural gas prices. Prices used to estimate reserves are included in *Oil and Natural Gas Reserves* above.

Extensions and Discoveries during the year ended December 31, 2016 were from the Company's operated Eagle Ford and non-operated Bakken properties.

All of the Company's purchases of minerals in place reserves during the year ended December 31, 2015, occurred in the Eagle Ford property in Gonzales County, Texas.

Based on the Company's year-end 2015 reserve report, the Company expects to drill all of its PUD locations within five years.

The total proved reserves increase of 10.8 MMBoe during 2014 is comprised of 6.1 MMBoe in proved developed and 4.7 MMBoe in proved undeveloped reserves.

During 2014, the Company added 2.4 MMBoe in proved reserves due to extension and discoveries, the majority of which is due to successful drilling in its operated Eagle Ford property in Fayette and Gonzales counties, Texas. Both new wells drilled and completed during 2014 along with the PUD locations that were added because of this successful drilling contributed to the increase in proved reserves. Purchase of minerals in place of 8.5 MMBoe were as a result of the Exchanges Agreement whereby Oak Valley acquired the legacy Earthstone assets through a reverse acquisition and the Flatonia Contribution Agreement where the Company acquired additional interests in its operated Eagle Ford property.

All of the Company's increases through extensions and discoveries occurred in its operated Eagle Ford property in Fayette and Gonzales counties, Texas as a result of successful drilling during 2014 which added additional PUD locations as well.

PUDs that were converted during the year occurred in both the Company's operated Eagle Ford and non-operated Bakken properties and 62% of the conversions occurred in the Eagle Ford property.

Extensions and Discoveries were from the Company's operated Eagle Ford and non-operated Bakken properties.

All of the Company's purchases of PUD reserves occurred in the Eagle Ford property in Gonzales County, Texas.

Based on the Company's year-end 2016 reserve report, the Company expects to drill all of its PUD locations within five years.

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lack sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. PUD locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

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

The following Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) has been developed utilizing ASC 932, *Extractives Activities – Oil and Gas* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's third party engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure 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 commodity prices will probably differ from those 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% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- Future net revenues may be subject to different rates of income taxation

At December 31, 2016, 2015 and 2014, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Prices used to estimate reserves are included in *Oil and Natural Gas Reserves* above. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying 10% discount factor.

The Standardized Measure is as follows (*in thousands*):

	December 31, 2016	December 31, 2015	December 31, 2014
Future cash inflows	$ 346,948	$ 481,131	$ 1,464,138
Future production costs	(172,062)	(192,349)	(427,113)
Future development costs	(29,814)	(91,725)	(312,010)
Future income tax expense	—	—	(180,248)
Future net cash flows	145,072	197,057	544,767
10% annual discount for estimated timing of cash flows	(59,189)	(92,661)	(288,911)
Standardized measure of discounted future cash flows	$ 85,883	$ 104,396	$ 255,856

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

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 three year period ended December 31, 2016 (*in thousands*):

	December 31, 2016	December 31, 2015	December 31, 2014
Beginning of year	$ 104,396	$ 255,856	$ 125,357
Sales of oil and gas produced, net of production costs	(24,998)	(29,152)	(35,794)
Sales of minerals in place	—	(2,470)	—
Net changes in prices and production costs	(102,143)	(288,064)	(34,681)
Extensions, discoveries, and improved recoveries	241	6,514	54,157
Changes in income taxes, net (1)	—	88,944	(88,944)
Previously estimated development costs incurred during the period	27,770	26,977	18,252
Net changes in future development costs	102,267	6,697	7,028
Purchases of minerals in place	16,921	7,695	163,309
Revisions of previous quantity estimates	(45,239)	(16,671)	16,283
Accretion of discount	11,506	25,586	12,536
Changes in timing of estimated cash flows and other	(4,838)	22,484	18,353
End of year	$ 85,883	$ 104,396	$ 255,856

(1) As a result of the December 19, 2014 Exchange, all historical financial information contained in this report is that of OVR and its subsidiaries. OVR, is a partnership for federal tax purposes and is not subject to federal income taxes or state or local income taxes that follow the federal treatment, and therefore OVR did not pay or accrue for such taxes. Pursuant to the Exchange OVR's subsidiaries have become subsidiaries of Earthstone Energy, Inc., which is a taxable entity; as such estimated tax expense was included in the Standardized Measure for December 31, 2014.

Exhibit 21.1

SUBSIDIARIES OF THE COMPANY

	Jurisdiction of Organization
Earthstone Operating, LLC	Texas
Earthstone Legacy Properties, LLC	Texas
Earthstone Energy Holdings, LLC	Delaware
EF Non-Op, LLC	Texas
Sabine River Energy, LLC	Texas
Lynden Energy Corp.	British Columbia, Canada
Lynden USA Inc.	Utah
Lynden USA Operating, LLC	Texas

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100
AUSTIN, TEXAS 78729-1707
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Earthstone Energy, Inc. for the year ended December 31, 2016, 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 March 1, 2017, into the Registration Statements on Form S-3 (File Nos. 333-205466 and 333-213543) and Form S-8 (File No. 333-210734) filed with the U.S. Securities and Exchange Commission.

W. Todd Brooker Sincerely,

STATE OF TEXAS
W. TODD BROOKER
83462
LICENSED
PROFESSIONAL ENGINEER

W. Todd Brooker, P.E.
President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

March 15, 2017

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 15, 2017, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Earthstone Energy, Inc. on Form 10-K for the year ended December 31, 2016. We consent to the incorporation by reference of said reports in the Registration Statements of Earthstone Energy, Inc. on Form S-3 (File No. 333-213543 and File No. 333-205466) and on Form S-8 (File No. 333-210734).

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2017

Exhibit 23.3

Consent of Independent Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statement of Earthstone Energy, Inc. (Form S-3 File No. 333-205466 and 333-213543, Form S-8 File No. 333-210734) of our report dated March 11, 2016, relating to the consolidated financial statements of Earthstone Energy, Inc. and subsidiaries (formerly Oak Valley Resources, LLC) included in the Annual Report on Form 10-K of Earthstone Energy, Inc. for the year ended December 31, 2016, and to the reference to our firm under the heading “Experts” in the Registration Statement.

/s/ WEAVER AND TIDWELL, L.L.P.

Houston, Texas
March 15, 2017

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Frank A. Lodzinski, certify that:

1. I have reviewed this annual report on Form 10-K of Earthstone 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.

Date: March 15, 2017

/s/ Frank A. Lodzinski
Frank A. Lodzinski
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tony Oviedo, certify that:

1. I have reviewed this annual report on Form 10-K of Earthstone 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.

Date: March 15, 2017

/s/ Tony Oviedo

Tony Oviedo
Executive Vice President – Accounting and Administration

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Earthstone Energy, Inc. (the "Company") for the period ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Lodzinski, President and 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.

Date: March 15, 2017

/s/ Frank A. Lodzinski
Frank A. Lodzinski
President and Chief Executive Officer

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

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Earthstone Energy, Inc. (the “Company”) for the period ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Tony Oviedo, Executive Vice President – Accounting and Administration 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.

Date: March 15, 2017

/s/ Tony Oviedo
Tony Oviedo
Executive Vice President – Accounting and Administration

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 99.1

EVALUATION SUMMARY

EARTHSTONE ENERGY, INC. INTERESTS

TOTAL PROVED RESERVES
CERTAIN PROPERTIES IN VARIOUS STATES

AS OF DECEMBER 31, 2016

SEC PRICE CASE

CG&A

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

EVALUATION SUMMARY

EARTHSTONE ENERGY, INC. INTERESTS

TOTAL PROVED RESERVES
CERTAIN PROPERTIES IN VARIOUS STATES

AS OF DECEMBER 31, 2016

SEC PRICE CASE

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS
Texas Registered Engineering Firm F-693

/S/ W. TODD BROOKER

W. TODD BROOKER, P.E.
PRESIDENT

/S/ ROBERT P BERGERON, JR.

ROBERT P. BERGERON, JR., P.E.
RESERVOIR ENGINEER

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100
AUSTIN, TEXAS 78729-1106
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

March 1, 2017

Robert Anderson
Executive V.P. – Corporate Development & Engineering
Earthstone Energy, Inc.
1400 Woodloch Forest Dr., Suite 300
The Woodlands, Texas 77380

Re: Evaluation Summary – SEC Price Case
Earthstone Energy, Inc. Interests
Total Proved Reserves
Certain Properties in Various States
As of December 31, 2016

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Mr. Anderson:

As requested, this report was prepared on March 1, 2017 for the purpose of submitting our estimates of proved reserves and forecasts of economics attributable to the *Earthstone Energy, Inc*. ("Earthstone") interests. We evaluated 100% of Earthstone's reserves, which are made up of oil and gas properties in various states. This report utilized an effective date of December 31, 2016, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the Securities and Exchange Commission (SEC). The results of this evaluation are presented in the accompanying tabulation, with a composite summary of the values presented below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Proved Undeveloped	Total Proved
Net Reserves						
Oil	- Mbbl	5,774.0	277.1	1.6	1,058.5	7,111.2
Gas	- MMcf	12,766.7	707.0	71.4	6,855.5	20,400.6
NGL	- Mbbl	1,044.7	6.3	0.0	488.3	1,539.4
Net Revenue						
Oil	- M$	227,367.9	9,829.0	61.8	42,966.2	280,224.9
Gas	- M$	28,179.0	1,361.6	146.7	16,706.0	46,393.2
NGL	- M$	13,662.5	83.9	0.0	6,583.5	20,329.9
Severance Taxes	- M$	15,642.6	1,150.1	9.7	2,815.1	19,617.3
Ad Valorem Taxes	- M$	4,146.8	20.1	3.8	1,257.6	5,428.3
Operating Expenses	- M$	98,400.0	2,910.2	356.1	10,934.5	112,600.8
Other Deductions	- M$	27,013.5	1,471.2	40.7	5,890.2	34,415.6
Investments	- M$	0.0	2,973.5	0.0	26,840.3	29,813.8
Net Operating Income (BFIT)	- M$	124,006.6	2,749.5	-201.9	18,518.1	145,072.4
Discounted @ 10%	**- M$**	**82,220.6**	**1,203.2**	**-183.0**	**2,642.5**	**85,883.3**

The discounted cash flow value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc. ("CG&A").

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its "present worth". The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil volumes and NGL volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Hydrocarbon Pricing

As requested for the SEC scenario, the base oil and gas prices calculated for December 31, 2016 were $42.75/BBL and $2.481/MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, 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. The base oil price is based upon WTI-Cushing spot prices during 2016 and the base gas price is based upon Henry Hub spot prices during 2016. Prices were not escalated in the SEC scenario. Adjustments to oil and gas prices were accepted as provided by your office and may include adjustments for treating cost, transportation charges and/or crude quality and gravity corrections.

Capital, Expenses and Taxes

Capital expenditures, lease operating expenses and Ad Valorem tax values were forecast as provided by your office. As you explained, the capital costs were based on the most current estimates, lease operating expenses were based on the analysis of historical actual expenses, operating overhead is included for operated properties and no credit or deduction is made for producing overhead paid to the company by other owners of the operated properties. Capital costs and lease operating expenses were held constant in accordance with SEC guidelines. Severance tax rates were applied at normal state percentages of oil and gas revenue. Severance Tax rates in certain instances, where authorized by taxing authorities, have severance tax abatements and were provided by your office and applied when appropriate.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages 3 and 4 of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions which could affect the reserves and economics have not been considered. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

This evaluation includes 332 proved undeveloped locations, of which 32 are commercial in the SEC pricing scenario. Each of these commercial drilling locations proposed as part of Earthstone's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, Earthstone has indicated they have every intent to complete this development plan as scheduled. Furthermore, Earthstone has demonstrated that they have the proper company staffing, financial backing and prior development success to ensure this development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described on page 2 of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

Miscellaneous

An on-site field inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined, nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have not been included and, as suggested by your office, are expected to be immaterial.

The reserve estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. Ownership information and economic factors such as liquid and gas prices, price differentials and expenses was furnished by your office. To some extent, information from public records was used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. We do not own an interest in the properties or *Earthstone Energy, Inc.* and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Yours very truly,

CAWLEY, GILLESPIE & ASSOCIATES, INC.
TEXAS REGISTERED ENGINEERING FIRM F-693

HEADINGS

Table Number
Effective Date of the Evaluation
Identity of Interest Evaluated
Reserve Classification and Development Status
Operator – Property Name
Field (Reservoir) Names – County, State

FORECAST

(Columns)	
(1) (11) (21)	Calendar or Fiscal years/months commencing on effective date.
(2) (3) (4)	Gross Production (8/8th) for the years/months which are economical. These are expressed as thousands of barrels (Mbbl) and millions of cubic feet (MMcf) of gas at standard conditions. Total future production, cumulative production to effective date, and ultimate recovery at the effective date are shown following the annual/monthly forecasts.
(5) (6) (7)	Net Production accruable to evaluated interest is calculated by multiplying the revenue interest times the gross production. These values take into account changes in interest and gas shrinkage.
(8)	Average (volume weighted) gross liquid price per barrel before deducting production-severance taxes.
(9)	Average (volume weighted) gross gas price per Mcf before deducting production-severance taxes.
(10)	Average (volume weighted) gross NGL price per barrel before deducting production-severance taxes.
(12)	Revenue derived from oil sales -- column (5) times column (8).
(13)	Revenue derived from gas sales -- column (6) times column (9).
(14)	Revenue derived from NGL sales -- column (7) times column (10).
(15)	Revenue derived from hedge sources.
(16)	Revenue not derived from column (12) through column (15); may include electrical sales revenue and saltwater disposal revenue.
(17)	Total Revenue – sum of column (12) through column (16).
(18)	Production-Severance taxes deducted from gross oil, gas and NGL revenue.
(19)	Ad Valorem taxes.
(20)	$/BOE6 – is the total of column (22), column (25), column (26), and column (27) divided by Barrels of Oil Equivalent (“BOE”). BOE is net oil production column (5) plus net gas production column (6) converted to oil at six Mcf gas per one bbl oil plus net NGL production column (7) converted to oil at one bbl NGL per 0.65 bbls of oil.
(22)	Operating Expenses are direct operating expenses to the evaluated working interest and may include combined fixed rate administrative overhead charges for operated oil and gas producers known as COPAS.
(23)	Average gross wells.
(24)	Average net wells are gross wells times working interest.
(25)	Work-over Expenses are non-direct operating expenses and may include maintenance, well service, compressor, tubing, and pump repair.
(26)	3rd Party COPAS are combined fixed rate administrative overhead charges for non-operated oil and gas producers.
(27)	Other Deductions may include compression-gathering expenses, transportation costs and water disposal costs.
(28)	Investments, if any, include re-completions, future drilling costs, pumping units, etc. and may include either tangible or intangible or both, and the costs for plugging and the salvage value of equipment at abandonment may be shown as negative investments at end of life.
(29) (30)	Future Net Cash Flow is column (17) less the total of column (18), column (19), column (22), column (25), column (26), column (27), and column (28). The data in column (29) are accumulated in column (30). Federal income taxes have not been considered.
(31)	Cumulative Discounted Cash Flow is calculated by discounting monthly cash flows at the specified annual rates.

MISCELLANEOUS

DCF Profile	•	The cumulative cash flow discounted at six different interest rates are shown at the bottom of columns (30-31). Interest has been compounded monthly. The DCF's for the "Without Hedge" case may be shown to the left of the main DCF profile.
Life	•	The economic life of the appraised property is noted in the lower right-hand corner of the table.
Footnotes	•	Comments regarding the evaluation may be shown in the lower left-hand footnotes.
Price Deck	•	A table of oil and gas prices, price caps and escalation rates may be shown in the lower middle footnotes.

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method, which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for “resource plays,” where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method may also be applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained in this manner are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(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 a 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.

"(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.

"(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.

"(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.

"(18) **<u>Probable reserves</u>**. 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 (17)(iv) and (17)(vi) of this section (below).

"(17) **<u>Possible reserves</u>**. 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.

"(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 (22)(iii) of this section (above), 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."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required* , to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

"(26) **<u>Reserves</u>**. 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 (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)."