FORM 10-K

EARTHSTONE ENERGY INC - ESTE

Filed: March 15, 2018 (period: December 31, 2017)

Annual report with a comprehensive overview of the company

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, 2017

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
Class A Common Stock, $0.001 par value per share	NYSE

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, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth 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	☐
Emerging growth Company	☐		

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price of $10.01 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 $181,689,218.

As of March 5, 2018, 27,828,773 shares of the registrant's Class A Common Stock and 35,858,123 shares of Class B Common Stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

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

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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, potential acquisitions or mergers or prospects are also forward-looking statements. Actual results could differ materially from those anticipated in this filing or 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") and other oil and natural gas producing countries;
- 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 risk of the actual presence or recoverability of oil and natural gas reserves and that future production rates will be less than estimated;
- the potential for production decline rates and associated production costs for our wells to be greater than we forecast;
- the timing and extent of our success in developing, acquiring, discovering and producing oil and natural gas reserves;
- the ability and willingness of our partners under our joint operating agreements to join in our future development, exploration and production activities;
- our ability to acquire additional mineral leases;
- the cost and availability of high quality goods and services with fully trained and adequate personnel, such as drilling rigs and completion equipment on a timely basis and at reasonable prices;
- risks in connection with potential acquisitions and the integration of significant acquisitions or assets acquired through a merger;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits;
- the possibility that potential divestitures may not occur or could be burdened with unforeseen costs;
- unanticipated reductions in the borrowing base under the credit agreement we are party to;
- risks incidental to the drilling and operation of oil and natural gas wells including mechanical failures;
- the availability of sufficient pipeline and other transportation facilities to carry our production to market and the impact of these facilities on realized 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 for equity 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 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;
- 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; and
- possible adverse results from litigation and the use of financial resources to defend ourselves.

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. The ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of NGLs also differs significantly in price from a barrel of oil.

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

Completion – The process of treating and hydraulically fracturing a drilled well followed by 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 regulatory 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 – A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

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 and maintain 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, comprised largely of 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 Development Agreement or ***JDA*** – An agreement that provides for the joint development of a tract of land typically utilized after the leasing phase has concluded or when minerals are HBP.

Joint Operating Agreement or ***JOA*** – Any agreement between working interest owners concerning 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. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics.

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 the 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) non-property related expenses such as general and administrative expenses, debt service and future income tax expense, or (ii) 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 completion activities and the 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 from existing wells and completions 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 performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

Recompletion – The completion for production of an existing 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.

SEC – United States Securities and Exchange Commission.

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 predominately uses water and chemicals, with sand, that is injected into an oil or natural gas reservoir to create a fracture in the reservoir rock and create or enhance fluid flow.

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., a Delaware corporation (together with our consolidated subsidiaries, the "Company," "our," "we," "us," "Earthstone" or similar terms), is a growth-oriented independent oil and gas company engaged in the acquisition and development of oil and gas reserves through activities that include the acquisition, drilling and development of undeveloped leases, asset and corporate acquisitions and mergers and, to a lesser extent, exploration activities. 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. At present, our primary assets are located in the Midland Basin of west Texas and the Eagle Ford Trend of south Texas.

Historically, we have operated in multiple basins in order to enable us to benefit from regional differences in realized prices and the availability and cost of equipment and services. Starting in May 2017, with the closing of the Bold Transaction (more fully described below), our focus has been primarily in the Midland Basin of west Texas where our acreage has multiple stacked pay intervals in the Wolfcamp and, to a lesser extent the Spraberry formations. We believe the area is characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons and high drilling success rates. Since May 2017, we have used one drilling rig and successfully drilled nine wells in the Midland Basin. With approximately 943 potential gross drilling locations in the Midland Basin, our future development will be focused predominately on horizontal development drilling in the area. We currently intend to run one rig continuously in the Midland Basin and are considering deploying another rig in the second half of 2018, depending on commodity prices and the cost and availability of quality services. Our second area of focus is the Eagle Ford Trend where we have locations in the Eagle Ford and Austin Chalk formations. During 2017, we used one drilling rig and successfully drilled 11 Eagle Ford wells. We plan to have a similar drilling program in 2018 which should allow us to maintain our acreage positions. We have approximately 161 potential gross operated drilling locations in the Eagle Ford Trend for future development. In order to allow us to focus on the Midland Basin, during 2017, we divested our Bakken and other non-core properties and reduced our working interest in certain wells that we drilled in the Eagle Ford through joint development agreements while maintaining operatorship and our acreage positions.

Currently, our reserve portfolio primarily consists of assets in the Midland Basin of west Texas and the Eagle Ford Trend of south Texas. We have 26,665 net acres in the core of the Midland Basin, of which 77% is operated and 23% is non-operated. We hold an approximately 87% working interest in our operated acreage and an approximately 38% working interest in our non-operated acreage. Our operated acreage in the Midland Basin is primarily located in Reagan, Upton and Midland counties. Our non-operated acreage in the Midland Basin is located primarily in Howard, Glasscock, Martin and Midland counties. In total, we have an interest in approximately 195 gross producing wells in the Midland Basin. We have 19,856 net leasehold acres in the Eagle Ford Trend of south Texas, including 16,045 operated net leasehold acres in the crude oil window in Fayette, Gonzales and Karnes counties, with working interests ranging from approximately 16% to 50%, and 2,863 non-operated net leasehold acres located in the natural gas and condensate window in La Salle County, with an average working interest of approximately 13%. Our 948 remaining net leasehold acres located in the Eagle Ford Trend, reside in Frio and Wilson counties. In total, we have an interest in approximately 165 gross producing wells in the Eagle Ford Trend.

At December 31, 2017, our estimated proved oil and natural gas reserves were approximately 79,976 MBOE based on the reserve report prepared by Cawley, Gillespie & Associates, Inc. ("CG&A"), our independent reserve engineers. Based on this report, at December 31, 2017, our proved reserve quantities were approximately 59% oil, 19% natural gas, 22% NGLs and 25% classified as proved developed. The calculated percentages include proved developed non-producing reserves. Of these interests, approximately 45,346 MBOE are attributable to noncontrolling interests. See Note 8. *Noncontrolling Interests* in the Notes to Consolidated Financial Statements.

Our Business Strategy

Our current business strategy is to focus on the economic development of our existing acreage, increase our acreage and well locations in oil-rich areas of the Midland Basin and increase stockholder value through the following:

- pursue value-accretive acquisition and corporate merger opportunities;
- profitably increase cash flows, production and reserves by selectively developing our acreage base;
- expand our acreage positions and drilling inventory in our areas of primary interest through acquisitions and farm-in opportunities, with an emphasis on operated position and selective non-operated participations with capable operators;
- block up acreage to allow for 10,000-foot horizontal lateral drilling locations which provide higher economic returns;
- maintain operating control over the majority of our production, development and undeveloped acreage;

- cost-effectively produce, develop and exploit of our existing acreage positions; and
- maintain a strong balance sheet and financial flexibility.

Our Strengths

We believe that the following strengths will be beneficial in achieving our business goals:

- extensive horizontal development potential in one of the most oil rich basins of the United States;
- experienced management team with substantial technical and operational expertise and a history of successful acquisition and merger transactions;
- operating control over the majority of our production and development activities; and
- conservative balance sheet.

Recent Developments

Bold Contribution Agreement

In May, 2017, Earthstone completed a contribution agreement dated as of November 7, 2016 and as amended on March 21, 2017 (the "Bold Contribution Agreement"), by and among Earthstone, Earthstone Energy Holdings, LLC ("EEH"), Lynden US, Lynden USA Operating, LLC, a Texas limited liability company ("Lynden Op"), Bold Energy Holdings, LLC, a Texas limited liability company ("Bold Holdings"), and Bold Energy III LLC, a Texas limited liability company ("Bold"). The purpose of the Bold Contribution Agreement was to provide for, among other things described below, the business combination between Earthstone and Bold, which owned significant developed and undeveloped oil and natural gas properties in the Midland Basin of Texas (the "Bold Transaction").

The Bold Transaction was structured in a manner commonly known as an "Up-C." Under this structure and the Bold Contribution Agreement, (i) Earthstone recapitalized its common stock into two classes – Class A common stock, $0.001 par value per share (the "Class A Common Stock"), and Class B common stock, $0.001 par value per share (the "Class B Common Stock"), and all of Earthstone's existing outstanding common stock, $0.001 par value per share (the "Common Stock"), was recapitalized on a one-for-one basis for Class A Common Stock (the "Recapitalization"); (ii) Earthstone transferred all of its membership interests in Earthstone Operating, LLC, Sabine River Energy, LLC, EF Non-Op, LLC and Earthstone Legacy Properties, LLC (formerly Earthstone GP, LLC) and $36,071 in cash from the sale of Class B Common Stock to Bold Holdings (collectively, the "Earthstone Assets") to EEH, in exchange for 16,791,296 membership units of EEH (the "EEH Units"); (iii) Lynden US transferred all of its membership interests in Lynden Op to EEH in exchange for 5,865,328 EEH Units; (iv) Bold Holdings transferred all of its membership interests in Bold to EEH in exchange for 36,070,828 EEH Units and purchased 36,070,828 shares of Class B Common Stock issued by Earthstone for $36,071; and (v) Earthstone granted an aggregate of 150,000 fully vested shares of Class A Common Stock under Earthstone's 2014 Long-Term Incentive Plan, as amended (the "2014 Plan"), to certain employees of Bold. Each EEH Unit, together with one share of Class B Common Stock, are convertible into one share of Class A Common Stock.

Upon closing of the Bold Transaction on May 9, 2017, Bold Holdings owned approximately 61.4% of the outstanding shares of Class A Common Stock, on a fully diluted, as converted basis. The EEH Units and the shares of Class B Common Stock issued to Bold Holdings were not registered under the Securities Act but were issued by EEH and Earthstone in reliance on the exemption provided under Section 4(a)(2) of the Securities Act.

Pursuant to the terms of the Bold Contribution Agreement, at the closing of the Bold Transaction, Earthstone, Bold Holdings, and the unitholders of Bold Holdings entered into a registration rights agreement (the "Registration Rights Agreement") relating to the shares of Class A Common Stock issuable upon the exchange of the EEH Units and Class B Common Stock held by Bold Holdings or its unitholders. In accordance with the Registration Rights Agreement, Earthstone filed a registration statement (the "Registration Statement") with the SEC to permit the public resale of the shares of Class A Common Stock issued by Earthstone to Bold Holdings or its unitholders in connection with the exchange of Class B Common Stock and EEH Units in accordance with the terms of the First Amended and Restated Limited Liability Company Agreement of EEH (the "EEH LLC Agreement"). On October 18, 2017, the Registration Statement was declared effective by the SEC.

On May 9, 2017, in connection with the closing of the Bold Contribution Agreement, Earthstone, EnCap Investments L.P. ("EnCap"), Oak Valley Resources, LLC ("OVR"), and Bold Holdings entered into a voting agreement (the "Voting Agreement"), pursuant to which EnCap, OVR, and Bold Holdings agreed not to vote any shares of Class A Common Stock or Class B Common Stock held by them in favor of any action, or take any action that would in any way alter the composition of the board of directors of Earthstone (the "Board") from its composition immediately following the closing of the Bold Contribution Agreement as long as the Voting Agreement is in effect.

Immediately following the closing of the Bold Contribution Agreement, the Board was increased to nine members from eight members, four of which are designated by EnCap, three of which are independent, and two of which are members of our management, including Earthstone's Chief Executive Officer. At any time during the effectiveness of the Voting Agreement during which EnCap's collective ownership of Earthstone exceeds 50% of the total issued and outstanding voting stock, EnCap may remove and replace one director that was not originally designated by EnCap, and his or her successors. Any such removal and replacement must be conducted in accordance with the provisions of Earthstone's certificate of incorporation and bylaws then in effect. The Voting Agreement terminates on the earlier of (i) the fifth anniversary of the closing date of the Bold Contribution Agreement and (ii) the date upon which EnCap, OVR, and Bold Holdings collectively own, of record and beneficially, less than 20% of Earthstone's outstanding voting stock.

On May 9, 2017, the closing sale price of the Class A Common Stock was $13.58 per share. On May 10, 2017, the Class A Common Stock was uplisted from the NYSE American, LLC (formerly the NYSE MKT) (the "NYSE American") to the New York Stock Exchange (the "NYSE") where it is listed under the symbol "ESTE."

Credit Agreement

On May 9, 2017, in connection with the closing of the Bold Transaction, the Company exited its credit agreement dated December 19, 2014, by and among Earthstone and its subsidiaries, BOKF, NA dba Bank of Texas, and the Lenders party thereto (as amended, modified or restated from time to time, the "ESTE Credit Agreement"). At that time, all outstanding borrowings of $10.0 million under the ESTE Credit Agreement were repaid and $0.5 million of remaining unamortized deferred financing costs were expensed and included in Write-off of deferred financing costs in the Consolidated Statements of Operations.

On May 9, 2017, EEH (the "Borrower"), Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden Op, Bold, Bold Operating, LLC (the "Guarantors"), BOKF, NA dba Bank of Texas, as Agent and Lead Arranger, Wells Fargo Bank, National Association as Syndication Agent and the Lenders party thereto (the "Lenders"), entered into a credit agreement (as amended, modified or restated from time to time, the "EEH Credit Agreement").

The borrowing base under the EEH Credit Agreement is currently $185.0 million and is subject to redetermination on or about November 1st and May 1st of each year. The amounts borrowed under the EEH Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus 2.25% to 3.25% or (b) the prime lending rate of the Bank of Texas plus 1.25% to 2.25%, depending on the amounts borrowed under the EEH Credit Agreement. Principal amounts outstanding under the EEH Credit Agreement are due and payable in full at maturity on May 9, 2022. All of the obligations under the EEH Credit Agreement, and the guarantees of those obligations, are secured by substantially all of EEH's assets. Additional payments due under the EEH Credit Agreement include paying a commitment fee of 0.50% per year to the Lenders in respect of the unutilized commitments thereunder, as well as certain other customary fees.

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

In addition, the EEH Credit Agreement requires EEH to maintain the following financial covenants: a current ratio of not less than 1.0 to 1.0 and a leverage ratio of not greater than 4.0 to 1.0. Leverage ratio means the ratio of (i) the aggregate debt of EEH and its consolidated subsidiaries as at the last day of the fiscal quarter (excluding any debt from obligations relating to non-cash losses under Financial Accounting Standards Board ("FASB") ASC 815, *Derivatives and Hedging* (FASB ASC 815") as a result of changes in the fair market value of derivatives) to (ii) the product of EBITDAX for such fiscal quarter multiplied by four. The term "EBITDAX" means, for any period, the sum of consolidated net income for such period plus (a) the following expenses or charges to the extent deducted from consolidated net income in such period: (i) interest, (ii) taxes, (iii) depreciation, (iv) depletion, (v) amortization, (vi) non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives, (vii) exploration expenses, (viii) impairment expenses, and (ix) non-cash compensation expenses and minus (b) to the extent included in consolidated net income in such period, non-cash gains under FASB ASC 815 as a result of changes in the fair market value of derivatives.

The EEH Credit Agreement contains customary affirmative covenants and defines events of default to include failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default, and if Frank A. Lodzinski ceases to serve and function as Chief Executive Officer of EEH and the majority of the Lenders do not approve of Mr. Lodzinski's successor. Upon the occurrence and continuance of an event of default, the Lenders have the right to accelerate repayment of the loans and exercise their remedies with respect to the collateral.

On December 1, 2017, EEH entered into an amendment (the "Amendment") to the EEH Credit Agreement. Among other things, the Amendment (i) increased the borrowing base from $150.0 million to $185.0 million; (ii) eliminated the limitation on the Borrower to request a loan when the consolidated cash held by the Company exceeds a certain threshold; (iii) reduced the frequency of reporting of hedging agreements by the Borrower to the Lenders; (iv) allows for the sale or transfer of any oil and gas property or any interest in any oil and natural gas property in excess of 5% of the value of the Company's proved developed producing reserves, subject to a redetermination of the borrowing base; and (v) allows the Borrower to enter into hedging agreements pertaining to oil and natural gas properties to be acquired pursuant to a proposed acquisition and, if terminated, liquidated within ten business days.

Class A Common Stock Offering

In October 2017, we completed a public offering of 4,500,000 shares of Class A Common Stock, at a public offering price of $9.25 per share, receiving net proceeds of $39.4 million, after deducting underwriters' fees and offering expenses of $2.2 million. The net proceeds were used to repay outstanding indebtedness under the EEH Credit Agreement.

Bakken Divestiture

In December 2017, we closed the sale of all of our oil and natural gas leases, oil and natural gas wells and associated assets located in the Williston Basin in North Dakota (the "Bakken Sale") for a net cash consideration of approximately $26.4 million after normal and customary purchase price adjustments of $0.9 million to account for net cash flows from the effective date to the closing date. The sale resulted in a net gain of approximately $3.0 million recorded in *Gain on sale of oil and gas properties* in the Consolidated Statements of Operations. The effective date of the sale was December 1, 2017. The net proceeds were used to repay $25.0 million of outstanding borrowings under the EEH Credit Agreement and the remaining $1.4 million retained in cash for current operating funds.

Organizational Structure

Earthstone is the sole managing member of EEH, with a controlling interest in EEH. Earthstone, together with its wholly-owned subsidiary, Lynden Energy Corp., a corporation organized under the laws of British Columbia ("Lynden Corp"), and Lynden Corp's wholly-owned consolidated subsidiary, Lynden US and also a member of EEH, consolidates the financial results of EEH and records a noncontrolling interest in the Consolidated Financial Statements representing the economic interests of EEH's members other than Earthstone and Lynden US.

Our Operations

We are currently the operator of properties containing approximately 70% of our proved oil and natural gas reserves and 73% of our proved PV-10 as of December 31, 2017 (see reconciliation of PV-10 to the standardized measure of discounted future net cash flows in Item 2. Properties). As operator, we manage and are able to directly influence development and production of operations of our operated properties. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work on improving operating cost, production rates and reserves. 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.

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.

Operational Risks

Oil and natural gas exploitation, development and production involve a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will acquire, discover 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.

Marketing and Customers

We market the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2017, three purchasers accounted for 18%, 14% and 14%, respectively, of our revenue during the period. For the year ended December 31, 2016, two purchasers accounted for 41% and 19%, respectively, of our revenue during the period. For the year ended December 31, 2015, one purchaser accounted for 62% of our revenue during the period. No other customer accounted for more than 10% of our revenue during these periods. If a major customer decided to stop purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a materially adverse effect on our financial condition or results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Transportation

During the planning stage of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The purchaser of our oil takes delivery of the oil at the tank batteries and transports the oil by truck on a frequent interval, from which point it is transported by various modes by the purchaser to the eventual refining facility. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems.

In addition, we move the majority of our produced water by pipeline connected to our operated salt water disposal wells rather as wells as by truck to a final disposal destination.

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.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Segment Information and Geographic Area

Operating segments are defined under accounting principles generally accepted in the United States ("GAAP") as components of an enterprise that (i) engage in activities from which it may earn revenues and incur expenses (ii) for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on our organization and management, we have only one reportable operating segment, which is oil and natural gas acquisition, exploration and production. We consider drilling rig services ancillary to our oil and natural gas exploration and producing activities and manage these services to support such activities. All of our operations are currently conducted in Texas.

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.

Markets for Sale of Production

Our ability to market oil and natural gas found and produced, if any, will depend on numerous factors beyond our control, the effect of which cannot be accurately predicted or anticipated. Some of these factors include, without limitation, the availability of other domestic and foreign production, the marketing of competitive fuels, the proximity and capacity of pipelines, fluctuations in supply and demand, the availability of a ready market, the effect of United States federal and state regulation of production, refining, transportation and sales and general national and worldwide economic conditions. Additionally, we may experience delays in marketing natural gas production and fluctuations in natural gas prices and our marketing professionals may experience short-term delays in marketing oil due to trucking and refining constraints. There is no assurance that we will be able to market any oil or natural gas produced, or, if such oil or natural gas is marketed, that favorable prices can be obtained.

The United States natural gas market has undergone several significant changes over the past few decades. The majority of federal price ceilings were removed in 1985 and the remainder were lifted by the Natural Gas Wellhead Decontrol Act of 1989. Thus, currently, the United States natural gas market is operating in a free market environment in which the price of gas is determined by market forces rather than by regulations. At the same time, the domestic natural gas industry has also seen a dramatic change in the manner in which gas is bought, sold and transported. In most cases, natural gas is no longer sold to a pipeline company. Instead, the pipeline company now primarily serves the role of transporter and gas producers are free to sell their product to marketers, local distribution companies, end users or a combination thereof.

In recent years, oil, natural gas and NGLs prices have been under considerable pressure due to oversupply and other market conditions. Specifically, increased foreign production and increased efficiencies in horizontal drilling, combined with exploration of newly developed shale fields in North America, have dramatically increased global oil and natural gas production, which has led to significantly lower market prices for these commodities. In view of the many uncertainties affecting the supply and demand for oil, natural gas and NGLs, we are unable to accurately predict future oil, natural gas and NGLs prices or the overall effect, if any, that the decline in demand for and the oversupply of such products will have on our financial condition or results of operations.

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 various agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and other agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

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

Operational Regulations

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

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

Regulation of Transportation of Natural Gas

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

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

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

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

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

Environmental Regulations

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

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

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct on certain categories of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances found at the site. Under CERCLA, these potentially responsible persons may be subject to strict, joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are not presently aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

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

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

Water Discharges

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

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

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

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. In particular, the well completion technique known as hydraulic fracturing is used to stimulate production of oil and natural gas has come under increased scrutiny by the environmental community, and many local, state and federal regulators. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depths to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

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

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

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

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

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

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

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

Air Emissions

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

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

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

Climate Change

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

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

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

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

National Environmental Policy Act

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

Threatened and endangered species, migratory birds and natural resources

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act (“ESA”), the Migratory Bird Treaty Act and the Clean Water Act. The U.S. Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds we believe that we are in substantial compliance with the ESA and the Migratory Bird Treaty Act, and we are not aware of any proposed ESA listings that will materially affect our operations. The federal government in the past has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce our oil and natural gas reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Hazard communications and community right to know

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

Occupational Safety and Health Act

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

State Regulation

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

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

Related Insurance

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

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

Employees

As of December 31, 2017, we had 58 full-time employees, of which nine are management, 19 are technical personnel, 16 are administrative personnel and 14 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
Midland, Texas	9,200 sq. ft.	June 30, 2019	Office
Denver, Colorado (1)	7,000 sq. ft.	April 30, 2018	Office

(1) In June 2017, management announced that the office located in Denver, Colorado, will be closing upon the end of its lease term, which is April 30, 2018.

During 2017, aggregate rental payments for our office facilities totaled approximately $0.9 million.

Executive Officers of the Company

The following table sets forth, as of March 1, 2018, certain information regarding the executive officers of Earthstone:

Name	Age	Position
Frank A Lodzinski	68	Chairman of the Board, President and Chief Executive Officer
Robert J. Anderson	56	Executive Vice President, Corporate Development and Engineering
Tony Oviedo	64	Executive Vice President, Accounting and Administration
Mark Lumpkin, Jr.	44	Executive Vice President and Chief Financial Officer
Steven C. Collins	53	Executive Vice President, Completions and Operations
Timothy D. Merrifield	62	Executive Vice President, Geological and Geophysical
Francis M. Mury	66	Executive Vice President, Drilling and Development
Ray Singleton	66	Director and Executive Vice President

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 Earthstone 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 45 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 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 and member of the compensation committee of Yuma Energy, Inc. since October 2016 and previously served on its audit committee from September 2014 to October 2016. He holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

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.

Tony Oviedo has served as our Executive Vice President – Accounting and Administration (Principal Accounting Officer) since 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 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.

Mark Lumpkin, Jr. has over 20 years of experience including over 13 years of oil and gas finance experience. He has served as our Executive Vice President and Chief Financial Officer since August 2017. Immediately prior to joining Earthstone, he served as Managing Director at RBC Capital Markets in the Oil and Gas Corporate Banking group, beginning in 2011 with a focus on upstream and midstream debt financing. From 2006 until 2011, he was employed by The Royal Bank of Scotland ("RBS") in the Oil and Gas group within the Corporate and Investment Banking division, focusing primarily on the upstream subsector. Prior to RBS, he spent two years focused on capital markets and mergers and acquisitions primarily in the upstream sector at a boutique investment bank. Mr. Lumpkin graduated with a B.A. degree in Economics from Louisiana State University and graduated with a Master of Business Administration degree with a Finance concentration from Tulane University.

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.

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 Earthstone 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.

Ray Singleton is a petroleum engineer with over 38 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 the Company 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. 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.

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 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. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. When considering an investment in our shares of Class A Common Stock, 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.

We are a holding company and the sole manager of EEH. Our only material asset is our equity interest in EEH and, accordingly, we are dependent upon distributions from EEH to cover our corporate and other overhead expenses and pay taxes.

Upon the closing of the Contribution Agreement on May 9, 2017, we became a holding company and the sole manager of EEH and have no material assets other than our equity interest in EEH. We have no independent means of generating revenue. We expect EEH to reimburse us for our corporate and other overhead expenses, and to the extent EEH has available cash, we intend to cause EEH to make distributions to the holders of EEH Units, including us, in an amount sufficient to cover all applicable U.S. federal, state and local income taxes and non-U.S. tax liabilities of Earthstone, Lynden Corp and Lynden US, if any, at assumed tax rates. We will likely be limited, however, in our ability to cause EEH and its subsidiaries to make these and other distributions due to the restrictions under an agreement providing for our senior secured revolving credit facility (the "EEH Credit Agreement"). To the extent that we need funds, and EEH or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Oil, natural gas and natural gas liquids prices are volatile. Their prices since 2014 have adversely affected, and in the future may adversely affect, our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments. Volatile and lower prices may also 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, 2017, the West Texas Intermediate ("WTI") futures price for oil declined from a high of $107.26 per Bbl on June 20, 2014 to $26.21 per Bbl on February 11, 2016, and subsequently increased to reach a high of $60.01 per Bbl in December 2017; and the Henry Hub futures price for natural gas has declined from a high of $6.15 per MMBtu on February 19, 2014 to a low of $1.64 per MMBtu on March 3, 2016, and subsequently increased to reach a high of $3.69 per MMBtu in December 2017. 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 experienced 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;
- 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 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 and pricing differentials 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, gathering and processing 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 the EEH Credit Agreement, our borrowing base is subject to semi-annual redeterminations (May 1 and November 1) and our lenders have the right to call for an interim determination of the borrowing base under certain 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 EEH Credit Agreement to the extent our outstanding borrowings exceed the redetermined borrowing base and could 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 decline in the market 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 significant future write-downs of the financial carrying values of our properties.

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

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

If oil, natural gas and natural gas liquids prices fall below current levels for an extended period of time and all other factors remain equal, we may incur impairment charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are recorded. See *Note 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 the EEH 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, including capital expenditures, and we may not have sufficient funds to repay borrowings under the EEH Credit Agreement or any other obligation if required as a result of a borrowing base redetermination.

Availability under the EEH Credit Agreement is currently subject to a borrowing base of $185.0 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 the EEH 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 the EEH Credit Agreement (if prices are kept constant). Reductions in our borrowing base under the EEH 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 December 31, 2017, we had $25.0 million of borrowings outstanding under the EEH Credit Agreement. We may make further borrowings under the EEH Credit Agreement in the future. Any significant reduction in our borrowing base under the EEH 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 operations and cash flows. Further, if the outstanding borrowings under the EEH 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 requires significant decisions, complex analyses and assumptions in evaluating available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Our actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance will likely materially affect the estimated quantities and the estimated value of our reserves. In addition, we may later adjust estimates of proved reserves to reflect production history, results of exploration and development activities, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

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

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future estimated cash flows of those reserves, may also trigger impairment losses on certain properties, which may result in non-cash charges to earnings. See *Note 6. Oil and Natural Gas Properties*, to our consolidated financial statements included in this report.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2017, approximately 75% of our estimated reserves were classified as proved undeveloped. The development of our estimated proved undeveloped reserves of 60,015 MBOE will require an estimated $665.9 million of development capital over the next five years.

Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on successful drilling and completion results, future commodity prices, costs and economic assumptions that align with our internal forecasts, as well as access to liquidity sources, such as the capital markets, the EEH Credit Agreement and derivative contracts. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. Moreover, under the SEC regulations, we may be required to write down our proved undeveloped reserves if we do not drill or have a development plan to drill wells within a prescribed five-year period. The estimated reserve data assumes that we will make specified capital expenditures to timely 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 set forth in this report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2017, 2016 and 2015, 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 our business or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for statutory income tax purposes and our future income taxes will be dependent on our future taxable income. Actual future prices and costs may differ materially from those used in the estimates included in this report which could have a material effect on the value of our estimated reserves.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

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

Properties we acquire may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of a property. We may be required to assume the risk of the physical condition of properties in addition to the risk that they may not perform in accordance with our expectations.

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 uncertain to what degree 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.

Our acquisition, development and exploitation projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition and development of oil and natural gas reserves. We expect to fund our 2018 capital expenditures with cash on hand, cash generated by operations, borrowings under the EEH Credit Agreement and possibly through additional capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce reserves; and
- our ability to borrow under the EEH Credit Agreement.

If our revenues or the borrowing base under the EEH Credit Agreement decrease as a result of low oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. The failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production and would adversely affect our business, financial condition and results of operations.

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 recognize changes in the fair value of derivatives in current earnings. Accordingly, our earnings may fluctuate significantly and our results of operations may be significantly and adversely affected because of changes in the fair market value of our derivative instruments. As our derivative instrument contracts expire, there is no assurance that we will be able to replace them comparably.

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* and *Note 5. Derivative Instruments* in the Notes to Consolidated Financial Statements included in this report for additional information.

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.

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 and for the equipment and services required to develop and operate properties. 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 hence we may be at a competitive disadvantage to companies with larger financial resources than ours.

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

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

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

We 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. We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

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

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Extreme weather conditions could adversely affect our ability to conduct drilling and production activities in the areas where we operate.

Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions could also impact access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

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

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response, increasingly governments have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

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

At the federal level, the Obama Administration pledged for the Paris Agreement to meet an economy-wide target in 2025 of reducing greenhouse gas emissions by 26-28% below the 2005 level. To help achieve these reductions, federal agencies have been addressing climate change through a variety of administrative actions. The EPA thus issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. Beyond measuring and reporting, the EPA issued an “Endangerment Finding” under Section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, then President Obama released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and natural gas sector. Consistent with that strategy, the EPA issued final rules in 2016 for new and modified oil and natural gas production sources (including hydraulically fractured oil wells, natural gas well sites, natural gas processing plants, natural gas gathering and boosting stations and natural gas transmission sources) to reduce emissions of methane as well as volatile organic compound and toxic pollutants. However, in May 2017 the EPA temporarily stayed implementing portions of the new rule and in June 2017 proposed a two year stay of new requirements, and more recently the head of the EPA has announced the current administration's intent to roll back or repeal most, if not all, of the Obama administration's regulations restricting future greenhouse gas emissions. In June 2017, President Trump announced that the United States intends to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or a separate agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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

The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions from the oil and natural gas industry. Even if federal efforts in this area slow, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our oil and natural gas.

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

Our oil, natural gas and natural gas liquids is sold in 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 and results of operations. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut-in of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

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

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

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

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

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

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

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 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. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. This is more likely in areas with recent increased production, such as our Permian Basin area where we have significant development activities. These are risks for which we generally will not maintain insurance.

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

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

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 some 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 acquisition, exploration or development activities. The success and timing of exploration, acquisition 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.

We are subject to litigation relating to Bold and the Bold Transaction, and we may be subject to additional litigation, any of which could adversely affect our business, financial condition and operating results.

On June 7, 2017, litigation captioned *Olenik v. Lodzinksi et al.* was filed in the Delaware Court of Chancery seeking class action status, claiming a breach of fiduciary duty by our Board and others and challenging the fairness of the Bold Transaction. The plaintiff has requested an award of damages in an unspecified amount. The Company and the other defendants believe the suit is without merit and have mounted a vigorous defense. In addition, we may be subject to additional litigation relating to Bold or the Bold Transaction in the future. We cannot predict the outcome of the ongoing litigation or any litigation that may arise in the future, nor can we predict the amount of time and expense that will be required to resolve the ongoing litigation or any other litigation. While we will evaluate and defend against the ongoing litigation and any other litigation vigorously, the costs of the defense, including legal fees of directors under indemnification obligations, and other effects of such litigation could have an adverse effect on our business, financial condition and results of operations.

On August 18, 2017, litigation captioned *Trinity Royal Partners, LP v. Bold Energy III LLC, et al.* was filed with the 142nd Judicial District of the District Court in Midland County, Texas, asserting breach of contract and indemnity claims for alleged damages from loss of property relating to two oil and natural gas wells in which Bold was the operator. Trinity Royalty Partners, LP (“Trinity”) alleges that Bold is required to indemnify Trinity under the terms of an Assignment and a Participation and Joint Development Agreement between Bold and Trinity. Damages are alleged to include costs incurred in attempting to repair and restore an oil and natural gas well and for the loss of future reserves attributable to both wells. Trinity is seeking approximately $7.2 million in damages and attorneys' fees. Earthstone and Bold believe the suit is without any merit and Bold intends to mount a vigorous defense.

Hurricanes, earthquakes and other natural disasters could have an adverse effect on our business, financial condition and results of operations.

Some of our properties are located in areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage our assets and disrupt our production of oil and natural gas. In the third quarter of 2017, Hurricane Harvey caused disruptions in our operations and, as of December 31, 2017, we had incurred $0.2 million in losses. For more information regarding the impact of Hurricane Harvey on operating results, see Item 7 “Management's Discussion and Analysis of Financial Condition and Results of Operations.” Natural disasters can similarly affect our facilities as well. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially.

The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

Risks Related to the Ownership of our Class A Common Stock

We are a “controlled company” within the meaning of the NYSE rules and, as a result, qualify for and rely on exemptions from certain corporate governance requirements.

EnCap controls a majority of the combined voting power of all classes of our outstanding voting stock. As a result, we are a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These requirements will not apply to us as long as we remain a controlled company. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

Our principal stockholders hold a substantial majority of the voting power of our Class A Common Stock and Class B Common Stock.

Holders of Class A Common Stock and Class B Common Stock will vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or our Third Amended and Restated Certificate of Incorporation. EnCap, through its ownership of Bold Holdings, may be deemed to beneficially own approximately 63% of our voting interests. In addition, certain affiliates controlled by EnCap directly own approximately 8% of our Class A Common Stock. As a significant stockholder, EnCap and certain of its affiliates could limit the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our Company or delaying or preventing changes in control or changes in our management.

So long as EnCap and certain of its affiliates continue to control a significant amount of our outstanding voting securities, they will continue to be able to have significant influence over all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. Also, in any of these matters, the interests of our management team may differ or conflict with the interests of our other stockholders. In addition, EnCap and its affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential acquisition candidates or industry partners. EnCap and its affiliates may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Moreover, this concentration of stock ownership may also adversely affect the trading price of our Class A Common Stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

Future sales of our Class A Common Stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity may dilute your ownership in us.

We may sell additional shares of Class A Common Stock or securities convertible into shares of our Class A Common Stock in subsequent offerings. We cannot predict the size of future issuances of our Class A Common Stock or securities convertible into Class A Common Stock or the effect, if any, that future issuances and sales of shares of our Class A Common Stock will have on the market price of our Class A Common Stock. Sales of substantial amounts of our Class A Common Stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A Common Stock.

Bold Holdings and its permitted transferees have the right to exchange their EEH Units and shares of Class B Common Stock for our Class A Common Stock pursuant to the terms of the EEH LLC Agreement.

As of March 1, 2018, there were approximately 35.9 million shares of our Class A Common Stock that are issuable upon redemption or exchange of EEH Units and shares of Class B Common Stock that are held by Bold Holdings or its permitted transferees. Pursuant to the EEH LLC Agreement, subject to certain restrictions therein, holders of EEH Units and our Class B Common Stock are entitled to exchange such EEH Units and shares of Class B Common Stock for shares of our Class A Common Stock at any time. We also entered into a registration rights agreement pursuant to which the shares of Class A Common Stock which may be issued upon redemption or exchange of EEH Units and shares of Class B Common Stock, subject to certain limitations set forth therein, have been registered for subsequent offers and sales by Bold Holdings and its permitted transferees.

We have no plans to pay dividends on our Class A Common Stock. Stockholders may not receive funds without selling their shares.

We do not anticipate paying any cash dividends on our Class A Common Stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our Board and will depend upon various factors, including our business, financial condition, results of operations, capital requirements, and investment opportunities. In addition, the EEH Credit Agreement does not allow EEH to make any significant payments to us, which makes it highly unlikely that we would be in a position to pay cash dividends on our Class A Common Stock.

Our Board can, without stockholder approval, cause preferred stock to be issued on terms that could adversely affect our common stockholders.

Under our Third Amended and Restated Certificate of Incorporation, our Board is authorized to cause the Company to issue up to 20,000,000 shares of preferred stock, of which none are issued and outstanding as of the date of this report. Also, our Board, without stockholder approval, may determine the price, rights, preferences, privileges, and restrictions, including voting rights, of those shares. If the Board causes shares of preferred stock to be issued, the rights of the holders of our Class A Common Stock and Class B Common Stock would likely be subordinate to those of preferred holders and therefore could be adversely affected. The Board's ability to determine the terms of preferred stock and to cause its issuance, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could have the effect of making it more difficult for a third party to acquire a majority of our outstanding voting stock or otherwise seek to acquire us. Shares of preferred stock issued by us could include voting rights, or even super voting rights, which could shift the ability to control the Company to the holders of the preferred stock. Preferred stock could also have conversion rights into shares of Class A Common Stock at a discount to the market price of the Class A Common Stock which could negatively affect the market for our Class A Common Stock. In addition, preferred stock could have preference in the event of liquidation of the Company, which means that the holders of preferred stock would be entitled to receive the net assets of the Company distributed in liquidation before the Class A common stockholders receive any distribution of the liquidated assets. We have no current plans to issue any shares of preferred stock.

The price of our Class A Common Stock may fluctuate significantly, which could negatively affect us and holders of our Class A Common Stock.

The trading price of our Class A Common Stock may fluctuate significantly in response to a number of factors, many of which are beyond our control. For instance, if our financial results are below the expectations of securities analysts and investors, the market price of our Class A Common Stock could decrease, perhaps significantly. Other factors that may affect the market price of our Class A Common Stock include:

- changes in oil and natural gas prices;
- actual or anticipated fluctuations in our quarterly results of operations;
- our liquidity;
- sales of Class A Common Stock by our stockholders;

- changes in our cash flow from operations or earnings estimates;
- publication of research reports about us or the oil and natural gas exploration and production industry generally;
- competition for, among other things, capital, acquisition of reserves, undeveloped land, and skilled personnel;
- increases in market interest rates that may increase our cost of capital;
- changes in applicable laws or regulations, court rulings, and enforcement and legal actions;
- changes in market valuations of similar companies;
- adverse market reaction to any indebtedness we may incur in the future;
- additions or departures of key management personnel;
- actions by our stockholders;
- commencement of or involvement in litigation;
- news reports relating to trends, concerns, technological or competitive developments, regulatory changes, and other related issues in our industry;
- speculation in the press or investment community regarding our business;
- political conditions in oil and natural gas producing regions of the world;
- general market and economic conditions; and
- domestic and international economic, legal, and regulatory factors unrelated to our performance.

In addition, U.S. securities markets have experienced significant price and volume fluctuations. These fluctuations often have been unrelated to the operating performance of companies in these markets. Market fluctuations and broad market, economic, and industry factors may negatively affect the price of our Class A Common Stock, regardless of our operating performance. Any volatility or a significant decrease in the market price of our Class A Common Stock could also negatively affect our ability to make acquisitions using Class A Common Stock. Further, if we were to be the object of securities class action litigation as a result of volatility in our Class A Common Stock price or for other reasons, it could result in substantial costs and diversion of our management's attention and resources, which could negatively affect our financial results.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

As of December 31, 2017, we are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"). Section 404 requires that we document and test our internal control over financial reporting and issue our management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm issue an attestation report on such internal control. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in our internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our Class A Common Stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Anti-takeover provisions could make a third-party acquisition difficult.

Our Third Amended and Restated Certificate of Incorporation provides for a classified board of directors, with each member serving a three-year term. Provisions in our Third Amended and Restated Certificate of Incorporation could make it more difficult for a third party to acquire us without the approval of our Board. In addition, the Delaware corporate statutes also contain certain provisions that could make an acquisition by a third party more difficult.

Our stockholders may act by unilateral written consent.

Under our Third Amended and Restated Certificate of Incorporation, any action required to be taken at any annual or special meeting of our stockholders, or any action which may be taken at any annual or special meeting of such stockholders, may be taken without a meeting, without prior notice and without a vote, if a consent in writing, setting forth the action so taken, is signed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted. Thus, consents of this type can be effected without the participation or input of minority stockholders.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties

Midland Basin

We have an operated position of 20,498 net acres in the core of the Midland Basin of west Texas across Reagan, Upton, and Midland counties with an average working interest of approximately 87%. As of December 31, 2017, we had approximately 13 gross vertical and 26 gross horizontal operated producing wells. Current internal estimates indicate approximately 526 potential gross, largely de-risked, operated drilling locations, the vast majority of which are in various benches of the Wolfcamp and the Spraberry formations. Of these 526 operated locations, 466 locations are expected to have an average working interest of 79%, whereas 60 locations are expected to be operated units where we would hold less than a 50% working interest. We are actively pursuing trades and acquisitions of additional acreage that would increase our working interest in these 60 locations. At this time, we expect that these 60 locations would have an average working interest of approximately 28%.

We also have a non-operated position of 6,167 net acres in the Midland Basin of west Texas, located in Howard, Glasscock, Martin and Midland counties, Texas. As of December 31, 2017, we had an interest in approximately 134 gross vertical and 26 gross horizontal non-operated producing wells with an average working interest of approximately 37%.

We have identified approximately 417 potential gross horizontal locations in various benches of the Wolfcamp and Spraberry formations with an estimated average working interest of approximately 28%. We have also identified approximately 117 potential gross vertical well locations in the Clearfork, Spraberry, Wolfcamp, Strawn and Fussleman formations with an estimated average working interest of approximately 41%.

Eagle Ford Trend

As of December 31, 2017, we held 33,557 gross (16,045 net) operated 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 and Upper Eagle Ford formations. We serve as the operator with a range of approximately 16% to 50% undivided ownership interest in substantially all of the acreage.

As of December 31, 2017, we operated 91 gross Eagle Ford wells and 12 gross Austin Chalk wells and had non-operated interests in five gross producing Eagle Ford wells and one gross producing Austin Chalk well. We have identified a total of approximately 165 potential gross Eagle Ford drilling locations in this acreage. In addition, because our acreage position is prospective for the Austin Chalk and Upper Eagle Ford 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.

We have a non-operated position in 25,097 gross (2,863 net) acres within La Salle County, Texas. The acreage 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 15% in 7,075 gross acres, all of which is held by production. As of December 31, 2017, 30 gross wells were producing, and we have identified approximately 40 potential additional drilling locations.

b) Martin Ranch – We have a 10% working interest in 18,022 gross acres. As of December 31, 2017, 31 gross wells were producing, and we have identified approximately 134 potential drilling locations in the acreage.

Additionally, we have a non-operated position in 2,055 gross (948 net) acres within Frio and Wilson counties of Texas.

Other

Our other 2017 operations primarily related to our recently divested Bakken properties, and other non-core oil and natural gas properties.

Oil and Natural Gas Reserves

As of December 31, 2017, primarily all of our oil and natural gas reserves were located in the state of Texas. We expect to further develop these properties through additional drilling and completion operations. 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)* in Part II, Item 8 of the Notes to Consolidated Financial Statements of this report.

As of December 31, 2017, our estimated proved reserves totaled 79,976 MBOE and had a PV-10 value of approximately $598.6 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $592.7 million, all of which relate to our properties in Texas. In addition to the completion of the Bold Transaction in May 2017, we incurred approximately $81.1 million in capital expenditures, primarily drilling and completion costs, during 2017. We expect to further develop our properties through additional drilling.

2017 Activity in Proved Reserves

From January 1, 2017 to December 31, 2017, our total estimated proved reserves increased 564% from 12,051 MBOE to 79,976 MBOE. Of that, estimated proved developed reserves increased 113% from 9,361 MBOE to 19,961 MBOE and estimated proved undeveloped reserves increased 2,131% from 2,690 MBOE to 60,015 MBOE. These increases are primarily attributable to the Bold Transaction that closed in May 2017.

Proved Reserves as of December 31, 2017

The below table sets forth a summary of our estimated crude oil, natural gas and natural gas liquids reserves as of December 31, 2017, 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, 2017. 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.

Our proved reserve categories as of December 31, 2017 are summarized in the table below:

	Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	Total (MBOE) (2)	% of Total Proved	Undiscounted Future Net Cash Flows ($ In thousands)	PV-10 ($ In thousands)	Standardized Measure of Discounted Future Net Cash Flows ($ In thousands)	Future Capital Expenditures ($ In thousands)
PDP	10,854	21,387	3,754	18,172	23%	$ 414,383	$ 253,156	$ 250,644	$ —
PDNP	1,095	1,949	369	1,789	2%	36,224	20,637	20,432	11,177
PUD	35,378	67,752	13,345	60,015	75%	1,023,000	324,848	321,624	665,916
Total proved (1)	47,327	91,088	17,468	79,976	100%	$ 1,473,607	$ 598,641	$ 592,700	$ 677,093

(1) Includes 26.8 MMBbl of oil, 51.6 Bcf of natural gas and 9.9 MMBbl of NGL reserves attributable to noncontrolling interests. Additionally, $339.4 million of PV-10 and $320.1 million of standardized measure of discounted future net cash flows were attributable to noncontrolling interests.

(2) 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).

PV-10 is a non-GAAP measure that differs from a measure under 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 determine. 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) (1)	$	598,641
Future income taxes, discounted at 10%		(5,941)
Standardized measure of discounted future net cash flows (2)	$	592,700

(1) Includes $339.4 million attributable to noncontrolling interests.

(2) Includes $320.1 million attributable to noncontrolling interests.

Drilled But Uncompleted Wells

In order to achieve efficiencies from a pricing and logistics standpoint, our customary sequence of drilling and completion operations is to drill a group of wells and defer completion operations until all drilling operations for the group are concluded and then commence completion activities.

As of December 31, 2017, we had 16.2 net wells (1,789 MBOE) included in PDNP which included 13 gross (4.8 net wells) (1,673 MBOE) that were drilled but uncompleted. The costs associated with the drilled but uncompleted wells totaled $9.5 million. Subsequent to December 31, 2017, we have completed 10 gross (3.3 net) wells (1,092 MBOE) and completion operations are ongoing with the remaining 1.5 net wells (502 MBOE). We anticipate completion of all the remaining drilled but uncompleted wells by April 2018.

Reserve Quantity Information

The following table illustrates our estimated net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated. The oil prices as of December 31, 2017, 2016, and 2015 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 $51.34 per barrel, $42.75 per barrel, and $50.28 per barrel, respectively. The natural gas prices as of December 31, 2017, 2016 and 2015 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $2.98 per MMBtu, $2.48 per MMBtu and $2.59 per MMBtu, respectively. The natural gas liquids prices used to value reserves as of December 31, 2017, 2016 and 2015 averaged $22.59 per barrel, $13.21 per barrel and $14.11 per barrel, 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 changes in the quantities of our proved oil, natural gas and natural gas liquids reserves for the years ended December 31, 2017, 2016 and 2015 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
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
Extensions and discoveries	19,558	29,644	6,264	30,763
Sales of minerals in place	(1,833)	(6,853)	(1)	(2,976)
Purchases of minerals in place	28,176	46,709	9,950	45,911
Production	(1,828)	(3,260)	(500)	(2,872)
Revision to previous estimates	(3,857)	4,447	215	(2,901)
Balance - December 31, 2017 (1)	47,327	91,088	17,468	79,976
Proved developed reserves:				
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
December 31, 2017 (2)	11,949	23,336	4,123	19,961
Proved undeveloped reserves:				
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
December 31, 2017 (3)	35,378	67,752	13,345	60,015

(1) Includes 26.8 MMBbl of oil, 51.6 Bcf of natural gas and 9.9 MMBbl of NGL reserves attributable to noncontrolling interests.

(2) Includes 6.8 MMBbl of oil, 13.2 Bcf of natural gas and 2.3 MMBbl of NGL reserves attributable to noncontrolling interests.

(3) Includes 20.0 MMBbl of oil, 38.4 Bcf of natural gas and 7.6 MMBbl of NGL reserves attributable to noncontrolling interests.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* In 2017, total extensions and discoveries of 30,763 MBOE was a result of successful drilling results and well performance primarily related to the Midland Basin. The closing of the Bold Transaction in May 2017 which included primarily operated acreage in the Midland Basin was a significant contributor to this.
- *Sales of minerals in place.* Sales of minerals in place totaled 2,976 MBOE during 2017 and were primarily related to the disposition of our Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2017, total purchases of minerals in place of 45,911 MBOE were primarily attributable to the Bold Transaction, whereby the Company acquired interests in 63 producing oil and natural gas wells, four proved

developed non-producing wells and undeveloped acreage in the Midland Basin, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

- *Revision to previous estimates.* In 2017, the downward revisions of prior reserves of 2,901 MBOE consisted of negative revisions to PUD reserves of 4,832 MBOE with improved proved developed reserves of 1,931 MBOE. PUD revisions are a result of (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. Positive revisions are primarily a result of increased oil and natural gas prices during 2017.

Notable changes in proved reserves for the year ended December 31, 2016 included the following:

- *Extension and discoveries.* In 2016, total extensions and discoveries of 423 MBOE were primarily attributable to the successful drilling on the operated Eagle Ford and non-operated Bakken properties.
- *Purchase of minerals in place.* In 2016, total purchases of minerals in place of 10,647 MBOE were primarily attributable to our acquisition of Lynden Corp in May 2016 (the "Lynden Arrangement"), whereby we acquired interests in non-operated Midland Basin properties.
- *Revision to previous estimates.* In 2016, the downward revision to previous estimates of 10,128 MBOE for total proved reserves occurred primarily as a result of decreased oil and natural gas prices.

Notable changes in proved reserves for the year ended December 31, 2015 included the following:

- *Extensions and discoveries.* In 2015, total extensions and discoveries of 685 MBOE were primarily attributable to the successful drilling on the operated Eagle Ford and non-operated Bakken properties.
- *Sales of minerals in place.* Sales of minerals in place totaled 1,344 MBOE during 2015 and were primarily related to the disposition of our Louisiana properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2015, total purchases of minerals in place of 1,962 MBOE were primarily attributable to interests acquired in the Eagle Ford Trend.
- *Revision to previous estimates.* In 2015, the downward revision to previous estimates of 9,484 MBOE for total proved reserves occurred primarily as a result of decreased oil and natural gas prices.

Proved Undeveloped Reserves

Proved undeveloped reserves increased from 2,690 MBOE to 60,015 MBOE or 2,131%, for the year ended December 31, 2017 compared to the year ended December 31, 2016. Proved undeveloped reserves represent 75% of our total proved reserves. Certain previously booked PUDs were reclassified as proved developed reserves due to successful drilling efforts. Revisions of prior estimates include certain PUDs that were reclassified to unproved categories due to development plan changes. In accordance with our 2017 year-end independent engineering reserve report, we plan to drill all of our individual PUD drilling locations within the next five years.

Changes in our PUD reserves for the years ended December 31, 2017, 2016 and 2015 were as follows (*in MBOE*):

Proved undeveloped reserves at December 31, 2014	12,392
Conversions to developed	(1,700)
Extensions and discoveries	685
Purchases of minerals in place	1,924
Revision to previous estimates	(9,340)
Proved undeveloped reserves at December 31, 2015	3,961
Conversions to developed	(169)
Extensions and discoveries	293
Purchases of minerals in place	873
Revision to previous estimates	(2,268)
Proved undeveloped reserves at December 31, 2016	2,690
Conversions to developed	(2,756)
Extensions and discoveries	27,977
Sales of minerals in place	(391)
Purchases of minerals in place	37,327
Revision to previous estimates	(4,832)
Proved undeveloped reserves at December 31, 2017 (1)	60,015

(1) Includes 34,029 MBOE attributable to noncontrolling interests.

2017 Changes in PUD reserves

Conversions to developed. In our year-end 2016 plan to develop our PUDs within five years, we estimated that $6.9 million of capital would be incurred in 2017 and that we would convert 732 MBOE. Because of the improvement in commodity prices and the change in our development plan for 2017, we actually incurred $8.5 million to convert 622 MBOE to developed. Our plan changed in that we developed more oil PUDs and elected not to participate in natural gas PUDs which included the above mentioned 443 MBOE associated with the Eagle Ford non-participation. The capital to develop our oil PUDs was higher on a per unit basis than the natural gas PUDs, however, the margins are higher for oil PUDs. The oil PUDs further benefited our longer-term operated development plans. Since the Bold Transaction closed in May 2017, the associated capital plan for the Bold properties was not considered in our year-end 2016 report. We did however incur $63.4 million to convert 2,134 MBOE of purchased PUD reserves to Developed. We intend to convert our proved undeveloped reserves into proved developed producing reserves in accordance with our estimates as of the date of our year-end 2017 reserve report.

Extensions and discoveries. Additionally, 27,977 MBOE were added as extensions and discoveries due to successful drilling results on our acreage positions because of the wells we drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to our acreage. All of these drilling results increased the confidence of the reservoir continuity and performance of the associated reservoirs which increased the number of PUDs primarily in the Midland Basin.

Sales of minerals in place. Sales of minerals in place totaled 391 MBOE during 2017 and were primarily related to the disposition of our Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Purchases of minerals in place. During 2017, 37,327 MBOE were added to PUD reserves upon the closing of the Bold Transaction.

Revision to previous estimates. Revisions of 4,832 MBOE were primarily due to (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon the closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. This non-participation has no impact on our ability to participate in future wells in this acreage position.

2016 Changes in PUD reserves

In early 2016, due primarily to depressed prices of oil and natural gas, we placed a lower emphasis on the conversion of our PUDs into proved developed producing reserves. In our plan to convert these reserves over a five-year period, we estimated that $3.1 million of capital expenditure would be incurred in 2016, and the bulk of capital expenditures would occur over the following four years. Our actual 2016 capital expenditures for conversion of proved undeveloped reserves were $3.2 million, in line with our estimates. We also had estimated that these capital expenditures would result in 258 MBOE of proved developed producing reserves. Our actual estimated conversions were 169 MBOE. The difference was due primarily to one less location being drilled than we had estimated and lower initial reserve estimates for wells in certain units where all wells in the units had not been developed. This resulted in lower reserve estimates until the remaining wells in the units are drilled.

As of December 31, 2016, our estimated proved undeveloped reserves were significantly lower than as of December 31, 2015, due to lower oil and natural gas prices used in making our 2016 estimates.

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

2015 Changes in PUD reserves

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

Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2017 (*$ in thousands*):

Years Ended December 31, (1)	Future Production (MBOE) (2)	Future Cash Inflows (3)	Future Production Costs	Future Development Costs	Future Net Cash Flows
2018	400	$ 15,911	$ 2,079	$ 51,949	$ (38,117)
2019	2,283	89,608	11,751	114,947	(37,090)
2020	5,264	209,703	27,346	243,816	(61,459)
2021	7,565	289,293	39,170	212,498	37,625
2022	6,209	223,884	33,806	42,706	147,372
Thereafter	38,294	1,377,897	403,228	—	974,669
Total	60,015	$ 2,206,296	$ 517,380	$ 665,916	$ 1,023,000

(1) Beginning in 2018 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects from the results of proved undeveloped drilling from previous years. These production volumes, inflows, expenses, development costs and cash flows are limited to the PUD reserves and do not include any production or cash flows from the Proved Developed category which will also help to fund our capital program.

(2) 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).

(3) Computation is based on SEC pricing of (i) $48.91 per Bbl (WTI posted oil prices) and (ii) $2.53 per MMBtu (Henry Hub spot natural gas price), adjusted for location and quality by property.

Historically, our drilling programs have been substantially funded from our cash flow and borrowings under our credit facility. Based on current commodity prices and our current expectations over the next five years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings under the EEH Credit Agreement. In addition, historically, we have been able to take advantage of the capital markets, as needed, when opportunities arose.

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, 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 the State of Texas (License No. 83462) 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.

Robert J. 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 31 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, 2017, 2016, and 2015, the average sales price per unit sold and the average production cost per unit are presented below:

	Years Ended December 31,		
	2017	**2016**	**2015**
Sales Volumes:			
Oil (MBbl)	1,828	878	904
Natural gas (MMcf)	3,260	2,171	2,143
Natural gas liquids (MBbl)	500	225	176
Barrels of oil equivalent (MBOE)*	2,872	1,465	1,437
Average prices realized:**			
Oil (per Bbl)	$ 48.43	$ 39.13	$ 44.09
Natural gas (per Mcf)	$ 2.69	$ 2.32	$ 2.55
Natural gas liquids (per Bbl)	$ 21.51	$ 12.74	$ 12.29
Barrels of oil equivalent (per BOE)	$ 37.63	$ 28.86	$ 33.04
Production cost per BOE	$ 6.84	$ 10.28	$ 10.73

* 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).

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting. Our derivatives for 2017, 2016 and 2015 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.

The following tables below summarize the net quantities of oil, natural gas and natural gas liquids produced and sold by us, the average sales price per unit sold and the average production cost per unit for each of our core areas for the years ended December 31, 2017, 2016, and 2015.

Midland Basin

No results for 2015 have been presented below as they represent the operating results of properties acquired in the Bold Transaction completed in May 2017 and in the Lynden Arrangement completed in May 2016.

	Years Ended December 31,	
	2017	2016
Sales Volumes:		
Oil (MBbl)	1,059	139
Natural gas (MMcf)	1,821	367
Natural gas liquids (MBbl)	351	69
Barrels of oil equivalent (MBOE)*	1,714	269
Average prices realized:**		
Oil (per Bbl)	$ 48.42	$ 45.13
Natural gas (per Mcf)	$ 2.49	$ 2.42
Natural gas liquids (per Bbl)	$ 23.01	$ 15.81
Barrels of oil equivalent (per BOE)	$ 37.29	$ 30.68
Production cost per BOE	$ 4.65	$ 10.06

* 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).

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

Eagle Ford Trend

	Years Ended December 31,		
	2017	2016	2015
Sales Volumes:			
Oil (MBbl)	535	525	672
Natural gas (MMcf)	772	947	1,172
Natural gas liquids (MBbl)	94	118	143
Barrels of oil equivalent (MBOE)*	758	801	1,011
Average prices realized:**			
Oil (per Bbl)	$ 49.86	$ 39.30	$ 45.29
Natural gas (per Mcf)	$ 3.09	$ 2.39	$ 2.61
Natural gas liquids (per Bbl)	$ 18.52	$ 12.91	$ 13.26
Barrels of oil equivalent (per BOE)	$ 40.65	$ 30.50	$ 35.01
Production cost per BOE	$ 8.80	$ 6.86	$ 8.84

* 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).

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

Gross and Net Productive Wells

The following table summarizes our gross and net productive oil and natural gas wells by area as of December 31, 2017. A net well represents our percentage of ownership of a gross well.

	Oil		Natural Gas		Total	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Midland Basin	193	94	2	1	195	95
Eagle Ford Trend	109	46	56	6	165	52
Other (1)	1	1	-	-	1	1

(1) Other primarily includes our non-core oil and natural gas properties, which were divested in February 2018.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage by state as of December 31, 2017. Net acreage represents our percentage ownership of gross acreage.

	Developed		Undeveloped (1)		Total	
State	Gross	Net	Gross	Net	Gross	Net
Texas	77,098	39,532	23,588	6,989	100,686	46,521
Other	960	770	6,979	3,141	7,939	3,911
Total	78,058	40,302	30,567	10,130	108,625	50,432

The following table summarizes, as of December 31, 2017, the portion of our gross and net acreage subject to expiration over the next three years if not successfully developed or renewed.

	Expiring Acreage							
	2018		2019		2020		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	761	761	160	160	170	170	1,091	1,091
Eagle Ford Trend	4,342	2,171	14,446	2,254	3,709	1,473	22,497	5,898
Other	6,979	3,141	—	—	—	—	6,979	3,141
Total	12,082	6,073	14,606	2,414	3,879	1,643	30,567	10,130

We have development agreements related to certain of our operated leases in the Midland Basin which require us to drill 42 gross wells (31 net wells) over the next five years. If we do not drill the required wells, we would be in default of the agreements. All of the aforementioned wells are included in management's development plan.

Exploratory Wells and Development Wells

Set forth below for the three years ended December 31, 2017 is information concerning the number of wells we drilled during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells
Year	Productive	Dry	Productive	Dry	Drilled
2017	—	—	11.0	—	11.0
2016	—	—	7.7	—	7.7
2015	—	—	7.2	—	7.2

Present Activities

As of March 1, 2018, we had 7 gross (5.3 net) operated wells and 4 gross (0.8 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, 2017, 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. 15. Commitments and Contingencies* in the Notes to Consolidated Financial Statements included in Item 8 of this report.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information for Common Stock

Shares of our Class A Common Stock are listed on the NYSE under the symbol "ESTE." The following table sets forth the reported high and low sales prices of our Class A Common Stock for the periods indicated:

	Class A Common Stock Price	
Period	**High**	**Low**
2017		
First Quarter	$ 15.50	$ 11.26
Second Quarter	$ 15.00	$ 9.07
Third Quarter	$ 11.68	$ 8.49
Fourth Quarter	$ 11.13	$ 7.85
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

Holders

As of March 1, 2018, there were approximately 2,000 holders of record of our Class A Common Stock and approximately 30 holders of record of our Class B Common Stock.

Dividends

We have never paid dividends on our Class A Common Stock or Class B Common Stock and do not intend to pay a dividend in the foreseeable future. Furthermore, the EEH Credit Agreement restricts the payment of cash dividends. The payment of future cash dividends on our Class A Common Stock, if any, will be reviewed periodically by our Board 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

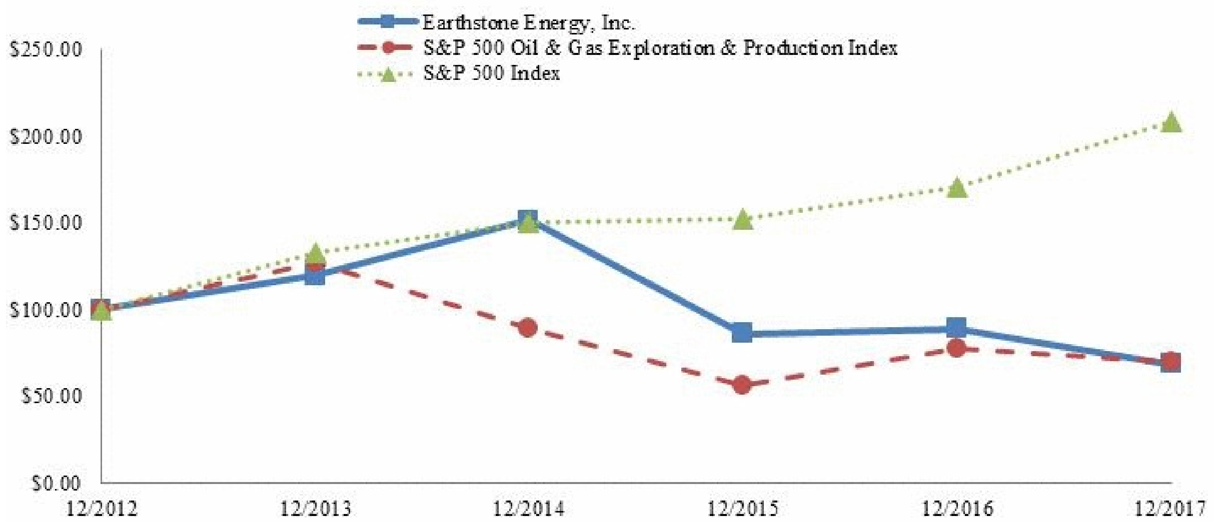
The following table sets forth information regarding our acquisition of shares of Class A Common Stock for the periods presented:

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plan or Programs
October 2017	—	—	—	—
November 2017	—	—	—	—
December 2017	31,614	$ 10.63	—	—

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

Performance Graph

The following graph reflects a comparison of the cumulative total stockholder return of our Class A Common Stock beginning December 31, 2013 through December 31, 2017, 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, 2012 in our Class A 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.



	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
Earthstone Energy, Inc.	$ 100.00	$ 119.43	$ 151.71	$ 85.93	$ 88.70	$ 68.62
S&P 500 Index	$ 100.00	$ 132.39	$ 150.51	$ 152.59	$ 170.84	$ 208.14
S&P 500 Oil & Gas Exploration & Production Index	$ 100.00	$ 127.09	$ 88.85	$ 56.23	$ 77.09	$ 69.33

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 our acquisition of three operating subsidiaries of OVR in exchange for shares of our common stock in December 2014 (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 was formed in December 2012 and 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 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,				
	2017	2016	2015	2014	2013
Summary of Operating Data:					
Sales volumes:					
Oil (MBbl)	1,828	878	904	403	163
Natural gas (MMcf)	3,260	2,171	2,143	2,132	2,635
Natural gas liquids (MBbl)	500	225	176	124	134
Barrel of oil equivalent (MBOE)*	2,872	1,465	1,437	882	737
Average realized prices:					
Oil (per Bbl)	$ 48.43	$ 39.13	$ 44.09	$ 86.29	$ 98.32
Natural gas (per Mcf)	$ 2.69	$ 2.32	$ 2.55	$ 4.39	$ 3.69
Natural gas liquids (per Bbl)	$ 21.51	$ 12.74	$ 12.29	$ 28.29	$ 28.88
Summary of Operations:					
Total revenues	$ 108,078	$ 42,269	$ 47,464	$ 47,611	$ 29,634
Lease operating expenses	$ 19,658	$ 15,067	$ 15,422	$ 10,130	$ 8,122
Severance taxes	$ 6,060	$ 2,198	$ 2,582	$ 2,002	$ 1,225
Impairment expense	$ 72,191	$ 24,283	$ 138,086	$ 19,359	$ 12,298
Depreciation, depletion and amortization	$ 36,915	$ 25,937	$ 31,228	$ 18,414	$ 17,111
Pretax loss	$ (61,106)	$ (54,013)	$ (143,097)	$ (6,729)	$ (19,875)
Income tax benefit (expense)	$ 16,373	$ (528)	$ 26,442	$ (22,105)	$ —
Net loss	$ (44,733)	$ (54,541)	$ (116,655)	$ (28,834)	$ (19,875)
Net loss attributable to Earthstone Energy, Inc.	$ (12,514)	$ (54,541)	$ (116,655)	$ (28,834)	$ (19,875)
Net loss per share attributable to Earthstone Energy, Inc.:**					
Basic and diluted	$ (0.53)	$ (2.92)	$ (8.43)	$ (3.11)	$ (2.18)
Summary of Cash Flows:					
Net cash provided by (used in) operating activities	$ 50,951	$ 1,712	$ (10,440)	$ 75,788	$ 15,283
Net cash used in investing activities	$ (86,303)	$ (59,868)	$ (66,602)	$ (107,437)	$ (117,116)
Net cash provided by (used in) financing activities	$ 48,107	$ 45,092	$ (141)	$ 106,673	$ 107,105
Summary Balance Sheet Data at Year End:					
Net oil and natural gas properties	$ 767,570	$ 269,402	$ 198,333	$ 295,877	$ 147,297
Total assets	$ 834,417	$ 316,512	$ 264,944	$ 451,388	$ 189,858
Long-term debt	$ 25,000	$ 12,693	$ 11,191	$ 11,191	$ 10,825
Total equity	$ 725,732	$ 241,457	$ 199,873	$ 316,528	$ 148,922

- * 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

This discussion and other items in this Annual Report on Form 10-K contain forward-looking statements and information that are based on management's beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words "believe," "anticipate," "estimate," "expect," "intend," "may," "will," "project," "forecast," "plan," and similar expressions are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to numerous risks, uncertainties and assumptions. See *Cautionary Statement Concerning Forward-Looking Statements* in this report. Certain of these risks are summarized in this report under *Item 1A. Risk Factors,* which you should read carefully in connection with our forward-looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

Overview

We are a growth-oriented independent oil and gas company engaged in the acquisition and development of oil and gas reserves through activities that include the acquisition, drilling and development of undeveloped leases, assets and corporate acquisitions and mergers and, to a lesser extent, exploration activities. Our operations are all in the upstream segment of the oil and natural gas industry and all of our properties are onshore in the United States. At present, our primary assets are located in the Midland Basin of west Texas and the Eagle Ford trend of south Texas.

Earthstone is the sole managing member of Earthstone Energy Holdings, LLC, a Delaware limited liability company (together with its wholly-owned consolidated subsidiaries, "EEH"), with a controlling interest in EEH. Earthstone, together with its wholly-owned subsidiary, Lynden Corp, and Lynden Corp's wholly-owned consolidated subsidiary, Lynden US and also a member of EEH, consolidates the financial results of EEH and records a noncontrolling interest in the Consolidated Financial Statements representing the economic interests of EEH's members other than Earthstone and Lynden US (collectively, the "Company" "our," "we," "us," or similar terms).

Areas of Operation

Our primary focus is concentrated in the Midland Basin of west Texas, a high oil and liquids rich resource which provides us with multiple horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates.

Midland Basin

We believe that the Midland Basin continues to have attractive economics and we expect to continue to focus our attention on growing our footprint through development drilling, acreage trades, asset acquisitions, and corporate merger and acquisition opportunities. We are intensely focused on expansion in the Midland Basin and production results continue to be as good or better than we projected.

We have been operating a one drilling rig program in the Midland Basin and plan to maintain a one rig program throughout 2018, with a view toward adding a second rig at some point in 2018 predicated upon commodity prices, availability of quality services, our drilling results and liquidity. In February 2018, we completed drilling our 11th Midland Basin well. We currently have a rig drilling the first well of a two-well pad in Reagan County. At present we have five wells waiting on completion and expect to have an inventory of seven wells when we initiate completion operations in April 2018.

We continue to be active in acreage trades and acquisitions in the Midland Basin which generally allow for longer laterals, increased operated inventory and greater operating efficiency.

Eagle Ford Trend

We recently completed an 11 well drilling program in southern Gonzales County, Texas. Completion operations on the 11 wells began in November 2017 and were concluded in January 2018. We currently expect our 2018 drilling program to be consistent with our 2017 program in this area. During each of the second and third quarters of 2017, we entered into Joint Development Agreements ("JDA") for these wells. In each of the two JDA's, the financial partner is obligated to pay a promoted (higher) share of the capital expenditures to earn 50% of our interest in these units and adjacent acreage. The two JDA's reduced our overall capital expenditures by approximately $17 million in 2017, allowing us to shift capital resources from the Eagle Ford to the Midland Basin while still maintaining operating control over our Eagle Ford program.

Recent Developments

Bold Contribution Agreement

On May 9, 2017, Earthstone completed the Bold Contribution Agreement. The primary purpose of the Bold Contribution Agreement was to provide for the business combination between Earthstone and Bold, which owned significant developed and undeveloped oil and natural gas properties in the Midland Basin of west Texas (the "Bold Transaction").

The Bold Transaction was structured in a manner commonly known as an "Up-C." Under this structure and the Bold Contribution Agreement, (i) Earthstone recapitalized its common stock into two classes – Class A Common Stock and Class B Common Stock, and all of Earthstone's existing outstanding Common Stock was recapitalized on a one-for-one basis for Class A Common Stock (the "Recapitalization"); (ii) Earthstone transferred all of its membership interests in Earthstone Operating, LLC, Sabine River Energy, LLC, EF Non-Op, LLC and Earthstone Legacy Properties, LLC (formerly Earthstone GP, LLC) and $36,071 in cash from the sale of Class B Common Stock to Bold Holdings (collectively, the "Earthstone Assets") to EEH, in exchange for 16,791,296 EEH Units; (iii) Lynden US transferred all of its membership interests in Lynden Op to EEH in exchange for 5,865,328 EEH Units; (iv) Bold Holdings transferred all of its membership interests in Bold to EEH in exchange for 36,070,828 EEH Units and purchased 36,070,828 shares of Class B Common Stock issued by Earthstone for $36,071; and (v) Earthstone granted an aggregate of 150,000 fully vested shares of Class A Common Stock under the 2014 Plan to certain employees of Bold. Each EEH Unit, together with one share of Class B Common Stock, are convertible into one share of Class A Common Stock.

Upon closing of the Bold Transaction on May 9, 2017, Bold Holdings owned approximately 61.4% of the outstanding shares of Class A Common Stock, on a fully diluted, as converted basis. The EEH Units and the shares of Class B Common Stock issued to Bold Holdings were not registered under the Securities Act, but were issued by EEH and Earthstone in reliance on the exemption provided under Section 4(a)(2) of the Securities Act.

Pursuant to the terms of the Bold Contribution Agreement, at the closing of the Bold Transaction, Earthstone, Bold Holdings, and the unitholders of Bold Holdings entered into the Registration Rights Agreement relating to the shares of Class A Common Stock issuable upon the exchange of the EEH Units and Class B Common Stock held by Bold Holdings or its unitholders. In accordance with the Registration Rights Agreement, Earthstone filed the Registration Statement with the SEC to permit the public resale of the shares of Class A Common Stock issued by Earthstone to Bold Holdings or its unitholders in connection with the exchange of Class B Common Stock and EEH Units in accordance with the terms of the EEH LLC Agreement. On October 18, 2017, the Registration Statement was declared effective by the SEC.

On May 9, 2017, in connection with the closing of the Bold Contribution Agreement, Earthstone, EnCap, OVR, and Bold Holdings entered into the Voting Agreement, pursuant to which EnCap, OVR, and Bold Holdings agreed not to vote any shares of Class A Common Stock or Class B Common Stock held by them in favor of any action, or take any action that would in any way alter the composition of the Board from its composition immediately following the closing of the Bold Contribution Agreement as long as the Voting Agreement is in effect.

Immediately following the closing of the Bold Contribution Agreement, the Board was increased to nine members from eight members, four of which are designated by EnCap, three of which are independent, and two of which are members of management, including Earthstone's Chief Executive Officer. At any time during the effectiveness of the Voting Agreement during which EnCap's collective ownership of Earthstone exceeds 50% of the total issued and outstanding voting stock, EnCap may remove and replace one director that was not originally designated by EnCap, and his or her successors. Any such removal and replacement will be conducted in accordance with the provisions of Earthstone's certificate of incorporation and bylaws then in effect. The Voting Agreement terminates on the earlier of (i) the fifth anniversary of the closing date of the Bold Contribution Agreement and (ii) the date upon which EnCap, OVR, and Bold Holdings collectively own, of record and beneficially, less than 20% of Earthstone's outstanding voting stock.

On May 9, 2017, the closing sale price of the Class A Common Stock was $13.58 per share. On May 10, 2017, the Class A Common Stock was uplisted from the NYSE American to the NYSE where it is listed under the symbol "ESTE."

Credit Agreement

On May 9, 2017, in connection with the closing of the Bold Transaction, the Company exited the ESTE Credit Agreement. At that time, all outstanding borrowings of $10.0 million under the ESTE Credit Agreement were repaid and $0.5 million of remaining unamortized deferred financing costs were expensed and included in Write-off of deferred financing costs in the Consolidated Statements of Operations.

On May 9, 2017, EEH entered into the EEH Credit Agreement.

The borrowing base under the EEH Credit Agreement is $185.0 million and is subject to redetermination on or about November 1st and May 1st of each year. The amounts borrowed under the EEH Credit Agreement bear annual interest rates at either (a) LIBOR plus 2.25% to 3.25% or (b) the prime lending rate of Bank of Texas plus 1.25% to 2.25%, depending on the amounts borrowed under the EEH Credit Agreement. Principal amounts outstanding under the EEH Credit Agreement are due and payable in full at maturity on May 9, 2022. All of the obligations under the EEH Credit Agreement, and the guarantees of those obligations, are secured by substantially all of EEH's assets. Additional payments due under the EEH Credit Agreement include paying a commitment fee of 0.50% per year to the Lenders in respect of the unutilized commitments thereunder, as well as certain other customary fees.

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

In addition, the EEH Credit Agreement requires EEH to maintain the following financial covenants: a current ratio of not less than 1.0 to 1.0 and a leverage ratio of not greater than 4.0 to 1.0. Leverage ratio means the ratio of (i) the aggregate debt of EEH and its consolidated subsidiaries as at the last day of the fiscal quarter (excluding any debt from obligations relating to non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives) to (ii) the product of EBITDAX for such fiscal quarter multiplied by four. The term "EBITDAX" means, for any period, the sum of consolidated net income for such period plus (a) the following expenses or charges to the extent deducted from consolidated net income in such period: (i) interest, (ii) taxes, (iii) depreciation, (iv) depletion, (v) amortization, (vi) non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives, (vii) exploration expenses, (viii) impairment expenses, and (ix) non-cash compensation expenses and minus (b) to the extent included in consolidated net income in such period, non-cash gains under FASB ASC 815 as a result of changes in the fair market value of derivatives.

The EEH Credit Agreement contains customary affirmative covenants and defines events of default to include failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default, and if Frank A. Lodzinski ceases to serve and function as Chief Executive Officer of EEH and the majority of the Lenders do not approve of Mr. Lodzinski's successor. Upon the occurrence and continuance of an event of default, the Lenders have the right to accelerate repayment of the loans and exercise their remedies with respect to the collateral. As of December 31, 2017, EEH was in compliance with these covenants under the EEH Credit Agreement.

Uplisting of Class A Common Stock

On May 8, 2017, the Board approved (i) the transfer of the listing of the Common Stock from the NYSE American to the NYSE, and (ii) the voluntary delisting of the Common Stock from the NYSE American. In connection with the closing of the Bold Transaction, all of the outstanding Common Stock was converted into Class A Common Stock, on a one-for-one basis. The Class A Common Stock began trading on the NYSE on May 10, 2017. The ticker symbol for the Class A Common Stock is "ESTE."

Closing of Denver Office

On July 31, 2017, we closed our Denver office and provided severance to our employees working there.

Class A Common Stock Offering

In October 2017, Earthstone completed a public offering of 4,500,000 shares of Class A Common Stock, at a public offering price of $9.25 per share, receiving net proceeds of $39.4 million, after deducting underwriters' fees and offering expenses of $2.4 million. The net proceeds were used to repay outstanding indebtedness under the EEH Credit Agreement.

Bakken Sale

In December 2017, we closed the Bakken Sale for a net cash consideration of approximately $26.4 million. The sale resulted in a net gain of approximately $3.0 million recorded in Gain on sale of oil and gas properties in the Consolidated Statements of Operations. The effective date of the sale was December 1, 2017. The net proceeds were used to repay $25.0 million of outstanding borrowings under the EEH Credit Agreement and the remaining $1.4 million was retained in cash for current operating funds.

Divestiture of Non-Core Assets

During 2017, we sold certain non-core properties for a total cash consideration of approximately $7.5 million, while eliminating approximately $4.0 million of future abandonment obligations. The sales resulted in a net gain of approximately $6.1 million recorded in Gain on sale of oil and gas properties in the Consolidated Statements of Operations.

Results of Operations

Year ended December 31, 2017, compared to the year ended December 31, 2016

	Years Ended December 31, 2017	Years Ended December 31, 2016	Change
Sales volumes:			
Oil (MBbl)	1,828	878	108%
Natural gas (MMcf)	3,260	2,171	50%
Natural gas liquids (MBbl)	500	225	123%
Barrels of oil equivalent (MBOE) (1)	2,872	1,465	96%
Average prices realized: (2)			
Oil (per Bbl)	$ 48.43	$ 39.13	24%
Natural gas (per Mcf)	$ 2.69	$ 2.32	16%
Natural gas liquids (per Bbl)	$ 21.51	$ 12.74	69%
(In thousands)			
Oil revenues	$ 88,536	$ 34,358	158%
Natural gas revenues	8,777	5,046	74%
Natural gas liquids revenues	10,765	2,865	276%
Total revenues	$ 108,078	$ 42,269	156%
Lease operating expense	$ 19,658	$ 15,067	30%
Severance taxes	$ 6,060	$ 2,198	176%
Rig idle and contract termination expense	$ —	$ 5,059	100%
Impairment expense	$ 72,191	$ 24,283	197%
Depreciation, depletion and amortization	$ 36,915	$ 25,937	42%
General and administrative expense	$ 20,466	$ 9,414	117%
Stock-based compensation	$ 6,601	$ 3,301	100%
Transaction costs	$ 4,732	$ 2,483	91%
Gain on sale of oil and gas properties	$ 9,105	$ 8	NM
Interest expense, net	$ (2,699)	$ (1,282)	111%
Write-off of deferred financing costs	$ (526)	$ —	NM
Loss on derivative contracts, net	$ (7,986)	$ (6,638)	20%
Income tax benefit (expense)	$ 16,373	$ (528)	NM

(1) 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).

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

NM – Not meaningful

Oil revenues

For the year ended December 31, 2017, oil revenues increased by approximately $54.2 million or 158% relative to the comparable period in 2016. Of the increase, approximately $8.2 million was attributable to an increase in our realized price and $46.0 million was attributable to increased volume. Our average realized price per Bbl increased from $39.13 for the year ended December 31, 2016 to $48.43 or 24% for the year ended December 31, 2017. We had a net increase in the volume of oil sold of 950 MBbls or 108%, primarily due to the Midland Basin properties we acquired in the Bold Transaction.

Natural gas revenues

For the year ended December 31, 2017, natural gas revenues increased by $3.7 million or 74% relative to the comparable period in 2016. Of the increase, approximately $0.8 million was attributable to an increase in our realized price and $2.9 million was attributable to increased volume. Our average realized price per Mcf increased from $2.32 for the year ended December 31, 2016 to $2.69 or 16% for the year ended December 31, 2017. The total volume of natural gas produced and sold increased 1,089 MMcf or 50% primarily due to the Midland Basin properties we acquired in the Bold Transaction.

Natural gas liquids revenues

For the year ended December 31, 2017, natural gas liquids revenues increased by $7.9 million or 276% relative to the comparable period in 2016. Of the increase, approximately $2.0 million was attributable to an increase in our realized price and $5.9 million was attributable to increased volume. The volume of natural gas liquids produced and sold increased by 276 MBbls or 123%, primarily due to the Midland Basin properties we acquired in the Bold Transaction.

Lease operating expense ("LOE")

LOE includes 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, re-engineering and workovers, 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.

LOE increased by $4.6 million or 30% for the year ended December 31, 2017 relative to the comparable period in 2016, primarily due to costs to operate the producing assets acquired in the Bold Transaction and added from drilling and completion operations that were not present in the prior year period.

Severance taxes

Severance taxes for the year ended December 31, 2017 increased by $3.9 million or 176% relative to the comparable period in 2016, primarily due to the increase in oil and natural gas prices. However, as a percentage of revenues from oil, natural gas, and natural gas liquids, severance taxes remained flat when compared to the prior year period.

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 July 2016, we entered into an agreement with a rig contractor to terminate our contract with the contractor. 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 to January 2016, when we suspended drilling and temporarily idled the drilling rig. In connection with the termination, we issued a three-year amortizing promissory note with a principal amount of $5.1 million, which was equivalent to the idle charges and contract termination fee.

Impairment

As a result of significant forward commodity price declines, as described below in *Liquidity and Capital Resources, Commodity Prices*, and the recording of certain acreage expirations, we recognized $72.2 million of non-cash asset impairments during the year ended December 31, 2017 that have negatively impacted our results of operations and equity. These impairments consisted of $63.1 million to our proved oil and natural gas properties and $9.1 million to our unproved oil and natural gas properties, primarily to our properties located in the Eagle Ford Trend of south Texas. See *Note 6. Oil and Natural Gas Properties* in the Notes to Consolidated Financial Statements for a discussion of how impairments are measured.

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

DD&A increased for the year ended December 31, 2017 by $11.0 million, or 42% relative to the comparable period in 2016, due to the addition of the assets acquired in the Bold Transaction and the Lynden Arrangement to the depletable base, as well as increased production volumes.

General and administrative expense ("G&A")

These expenses consist primarily of employee remuneration, professional and consulting fees and other overhead expenses. G&A increased by $11.1 million for the year ended December 31, 2017 relative to the comparable period in 2016, primarily due to both the retention of certain employees of Bold, as well as the payment and accrual of transition and severance totaling approximately $1.1 million to certain Bold and Denver office employees. Additionally, legal expenses increased due to litigation described in *Note 15. Commitments and Contingencies* in the Notes to Consolidated Financial Statements.

Stock-based compensation

Stock-based compensation includes the expense associated with grants under the 2014 Plan of restricted stock units ("RSUs") to employees and non-employee directors. Stock-based compensation was $6.6 million for the year ended December 31, 2017, as compared to $3.3 million in the prior year. However, the 2017 period is not comparable to the prior year period as the initial grant was made on May 20, 2016. The $3.3 million increase in stock-based compensation was primarily due to a $1.9 million increase during the current period due to the smaller amortization period beginning May 20, 2016 in the prior year and $1.4 million due to the 2017 grants.

Transaction costs

Transaction costs consist primarily of financial advisory, professional and consulting fees associated with the Bold Transaction.

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, 2017 was $2.7 million compared to $1.3 million for the comparable period in 2016. The $1.4 million increase in interest expense was primarily due to increased borrowings during the current period.

Gain on sale of oil and gas properties

During the year ended December 31, 2017, we sold all of our oil and natural gas leases, oil and natural gas wells and associated assets located in the Williston Basin in North Dakota. We also sold certain of our non-core oil and natural gas properties in Texas, Montana, Oklahoma and North Dakota. In connection with these sales, we recorded gains totaling $9.1 million. *See Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Loss on derivative contracts, net

For the year ended December 31, 2017, we recorded a net loss on derivative contracts of $8.0 million, consisting of net realized losses on settlements of $0.7 million and unrealized mark-to-market losses of $7.3 million. For the year 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.

Income tax benefit (expense)

Following the closing of the Bold Transaction, we continue to record an income tax provision consistent with our status as a corporation. 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 US, Earthstone, and Lynden Corp. 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 be offset by tax attributes of Earthstone. Following the Bold Transaction, Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the noncontrolling interest, as well as any standalone income or loss generated by each company. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

During the year ended December 31, 2017, we recorded a total tax benefit of $16.4 million which is primarily driven by the change in valuation allowance associated with the Bold Transaction. For Lynden US, we recorded an income tax benefit of $8.6 million, of which $4.8 million related to the reduction of that amount in Lynden US's deferred tax liability resulting from the federal corporate income tax rate reduction to 21% as described below. Additionally, we recorded an income tax benefit for Earthstone of $7.7 million which resulted from a change in assessment of the realization of its net deferred tax assets due to the deferred tax liability that was recorded with respect to its investment in EEH as part of the Bold Transaction as an adjustment to Additional paid-in capital within the Consolidated Balance Sheets. Additionally, Earthstone recorded income tax expense of $12.6 million related to the reduction of that amount in its deferred tax asset resulting from the federal corporate income tax rate reduction to 21% as described below, which was fully offset by the reduction in its valuation allowance for that amount because the future realization of such loss cannot be reasonably assured and is subject to a full valuation allowance.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the TCJA, resulting in significant modifications to existing law. Our consolidated financial statements for the year ended December 31, 2017, reflect certain effects of the TCJA, which includes a reduction in our corporate tax to 21%. Consistent with Staff Accounting Bulletin No. 118 issued by the SEC, which provides for a measurement period of one year from the enactment date to finalize the accounting for effects of the TCJA, the Company provisionally recorded income tax expense of $7.8 million related to the TCJA. In accordance with SEC guidance, provisional amounts may be refined as a result of additional guidance from, and interpretations by, U.S. regulatory and standard-setting bodies, and changes in assumptions. In the subsequent period, provisional amounts will be adjusted for the effects, if any, of interpretative guidance issued after December 31, 2017, by the U.S. Department of the Treasury. The effects of the TCJA may be subject to changes for items that were previously reported as provisional amounts, as well as any element of the TCJA for which a provisional estimate could not be made, and such changes could be material.

The Company has made provisional computations of the impact of the TCJA as provided for under SAB 118, including transition tax on the mandatory deemed repatriation of foreign earnings and executive compensation limitations under Internal Revenue Code Section 162(m), among others. The Internal Revenue Service is expected to issue additional guidance clarifying provisions of the Act. As additional guidance is issued one or more of the provisional amounts may change.

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

	Years Ended December 31, 2016	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)	1,465	1,437	2%
Average prices realized: (2)			
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%
Total revenues	$ 42,269	$ 47,464	-11%
Lease operating expense	$ 15,067	$ 15,422	-2%
Severance taxes	$ 2,198	$ 2,582	-15%
Rid idle and contract termination expense	$ 5,059	$ —	NM
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	$ —	NM
Transaction costs	$ 2,483	$ 589	322%
Gain on sale of oil and gas properties	$ 8	$ 1,617	-100%
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) 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).

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

NM – Not meaningful

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 Lynden 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 properties of 197 MBbls, our non-operated Eagle Ford properties 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 decreased by $0.4 million or 2% 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 July 2016, we entered into an agreement with a rig contractor to terminate our contract with the contractor. 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 to January 2016, when we suspended drilling and temporarily idled the drilling rig. In connection with the termination, we issued a three-year amortizing promissory note with a principal amount of $5.1 million, which was equivalent to the idle charges and contract termination fee.

Impairment

As a result of large commodity price declines and in spite of our operating achievements, we recognized $24.3 million of noncash asset impairments in 2016 that 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 oil and natural gas prices in 2016.

General and administrative expense ("G&A")

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

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 Bold Transaction and the Lynden Arrangement.

Interest expense, net

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 Corp. Our corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns. Taxable income of Earthstone, excluding the Lynden Corp. subsidiaries cannot be offset by tax attributes, including net operating losses of the Lynden Corp. subsidiaries, nor can taxable income of the Lynden Corp. subsidiaries be offset by tax attributes of Earthstone, excluding the Lynden Corp. subsidiaries. Excluding the Lynden Corp. 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.

Liquidity and Capital Resources

With the Bold Transaction, we acquired significant undeveloped acreage and future drilling locations. Drilling horizontal wells, generally consisting of 7,500 to 10,000-foot lateral lengths, in the Midland Basin is capital intensive. At December 31, 2017, we had approximately $23.0 million in cash and $160.0 million in unused borrowing capacity under the EEH Credit Agreement for a total of $183.0 million in liquidity. We currently estimate 2018 capital expenditures to be approximately $170.0 million, which assumes an approximate 20 well program running one rig for our operated acreage in the Midland Basin and an approximate 10 well program for our operated Eagle Ford acreage as well as some activity for our non-operated Midland Basin properties and land and infrastructure activities. We likely will outspend our cash flows provided by operating activities over at least the next twelve months from the date of this report based on current assumptions; however, we believe we will have sufficient liquidity with cash flows from operations and borrowings under the EEH Credit Agreement for the next 12 months to meet our cash requirements. We will continue to evaluate and prepare operationally for the possible deployment of a second rig in our operated Midland Basin acreage.

We expect to finance future acquisition and development activities through available working capital, cash flows from operating activities, borrowings under the EEH Credit Agreement, various means of corporate and project financing, assuming we can access debt and equity markets. 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 share of capital costs.

Cash Flows from Operating Activities

Cash flows provided by operating activities for the year ended December 31, 2017 were $51.0 million compared to $1.7 million for the year ended December 31, 2016. The increase in operating cash flows from the prior period was primarily due to changes in our working capital resulting from commodity price volatility and the producing assets acquired in the Bold Transaction and the Lynden Arrangement. We believe we have sufficient liquidity and capital resources to execute our business plan over the next 12 months and for the foreseeable future.

We had working capital, defined as Total current assets less Total current liabilities, as set forth in our Consolidated Balance Sheets, as a deficit of $21.8 million as of December 31, 2017 compared to a deficit of $11.5 million as of December 31, 2016. The working capital deficit, as defined above, is a result of the two-step drilling and completion process. Typically, we will drill numerous wells per pad and, once all the wells are drilled, they are completed and begin production. This process inherently involves timing differences between ultimate cash outflows and cash inflows.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2017 and 2016 were $86.3 million and $59.9 million, respectively. Cash flows used in investing activities for the year ended December 31, 2017 included $55.6 million required to complete the Bold Transaction and $65.3 million in capital expenditures primarily related to the drilling and completion of wells in the Midland Basin on acreage acquired in the Bold Transaction, offset by $34.7 million in proceeds from the divestiture of certain non-core assets. Cash flows used in investing activities for the year ended December 31, 2016 related primarily to the cash required to complete the Lynden Arrangement.

Cash Flows from Financing Activities

Cash flows provided by financing activities for the year ended December 31, 2017 were $48.1 million which consisted primarily of borrowings under the EEH Credit Agreement which were used to repay all outstanding borrowings under Bold's credit agreement assumed by EEH in the Bold Transaction and proceeds from the Class A Common Stock offering completed in October 2017 . Cash flows provided by financing activities for the year ended December 31, 2016 were $45.1 million which consisted primarily of proceeds from the common stock offering completed in June 2016.

Capital Expenditures

We have set our 2018 capital budget, which currently assumes a one-rig program for our operated acreage in the Midland Basin and a 10 well program for our operated Eagle Ford acreage. We will continue to evaluate and prepare operationally for the possible deployment of a second rig in our operated Midland Basin acreage in the latter half of 2018. Our anticipated capital expenditures for 2018 are currently estimated at $170 million.

Our accrual basis capital expenditures for the years ended December 31, 2017, 2016 and 2015 were as follows:

	Years Ended December 31,		
	2017	2016	2015
Drilling and completions	$ 76,253	$ 25,982	$ 46,388
Leasehold costs	3,067	2,595	10,474
Land	1,816	—	—
Total capital expenditures	$ 81,136	$ 28,577	$ 56,862

Public Offering

In October 2017, we completed a public offering of 4,500,000 shares of Class A Common Stock, at a public offering price of $9.25 per share, receiving net proceeds of $39.4 million, after deducting underwriters' fees and offering expenses of $2.2 million. The net proceeds from the offering were used to repay outstanding indebtedness under the EEH Credit Agreement.

Credit Agreement

In May 2017, in connection with the closing of the Bold Transaction, we became party to the EEH Credit Agreement. As of December 31, 2017, we had a $185.0 million borrowing base under the EEH Credit Agreement, of which $25.0 million was outstanding, bearing an annual interest rate of 3.7611%, resulting in an additional $160.0 million of borrowing base availability under the EEH Credit Agreement.

Impairments to Oil and Natural Gas Properties

During 2017, we recognized $72.2 million of non-cash asset impairments that negatively impacted our results of operations and equity. These impairments consisted of $63.1 million to our proved oil and natural gas properties and $9.1 million to our unproved oil and natural gas properties, primarily to our properties located in the Eagle Ford Trend of south Texas. See *Note 6. Oil and Natural Gas Properties* in the Notes to Consolidated Financial Statements for a discussion of how impairments are measured.

Hedging Activities

As of December 31, 2017, we had hedged a total of 1,483 MBbls of 2018 oil production at an average price of $51.38/Bbl and 548 MBbls of 2019 oil production at an average price of $52.32/Bbl. As of December 31, 2017, we had hedged a total of 810,000 MMBtu of 2018 natural gas production at an average price of $3.066/MMBtu.

In January 2018, we entered into additional fixed price oil and natural gas swap agreements, hedging an additional 365 MBbls of 2019 oil production at a price of $58.38/Bbl and 1,552,000 MMBtu of 2018 natural gas production at a price of $2.96/MMBtu.

Obligations and Commitments

We had the following contractual obligations and commitments as of December 31, 2017:

(In thousands)	2018	2019	2020	2021	2022	Thereafter
Debt (1)	$ 33	$ —	$ —	$ —	$ 25,000	$ —
Derivative liabilities	11,805	1,826	—	—	—	—
Asset retirement obligations	310	—	36	—	374	1,497
Gas contracts (2)	1,643	1,643	1,647	680	—	—
Office leases	854	723	—	—	—	—
Total	$ 14,645	$ 4,192	$ 1,683	$ 680	$ 25,374	$ 1,497

(1) 2018 amount represents interest payable under the EEH Credit Agreement as of December 31, 2017.

(2) 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.

Environmental Regulations

Our operations are subject to risks normally associated with the exploration for and the production of oil and natural gas, including blowouts, fires, and environmental risks such as oil spills or natural gas leaks that could expose us to liabilities associated with these risks.

In our acquisition of existing or previously drilled well bores, we 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. We maintain comprehensive insurance coverage that we believe 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 accrue to us. No claim has been made, nor are we aware of any liability which we may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations relating thereto.

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, 2017. 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

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

Our crude oil and natural gas derivative positions consist of swaps. Swaps are designed so that we receive or make payments based on a differential between fixed and variable prices for crude oil and natural gas. We have elected to not designate any of our derivative contracts for hedge accounting. Accordingly, we record 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 and are included in the Consolidated Balance Sheets as assets or liabilities.

Income Taxes and Uncertain Tax Positions

We are a U.S. company operating primarily in Texas, as of December 31 2017, as well as one foreign legal entity, Lynden Corp, which is a Canadian company. 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.

Following the closing of the Bold Transaction, we continue to record an income tax provision consistent with our status as a corporation. 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 US, Earthstone, and Lynden Corp. 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 be offset by tax attributes of Earthstone. Following the Bold Transaction, Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the noncontrolling interest, as well as any standalone income or loss generated by each company. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

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, 2017 and 2016, the Company has recorded a valuation allowance for its deferred tax assets in the Consolidated Balance Sheets.

We apply 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 we 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. Our tax positions related to our pass-through status and state income tax liability, including deductibility of expenses, have been reviewed by our management and they believe those positions would more likely than not be sustained upon examination. Accordingly, we have not recorded an income tax liability for uncertain tax positions at December 31, 2017, 2016 or 2015.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the TCJA, resulting in significant modifications to existing law. Our consolidated financial statements for the year ended December 31, 2017, reflect certain effects of the TCJA, which includes the federal corporate income tax rate reduction to 21%. Consistent with Staff Accounting Bulletin No. 118 issued by the SEC, which provides for a measurement period of one year from the enactment date to finalize the accounting for effects of the TCJA, the Company provisionally recorded income tax expense of $7.8 million related to the TCJA. In accordance with SEC guidance, provisional amounts may be refined as a result of additional guidance from, and interpretations by, U.S. regulatory and standard-setting bodies, and changes in assumptions. In the subsequent period, provisional amounts will be adjusted for the effects, if any, of interpretative guidance issued after December 31, 2017, by the U.S. Department of the Treasury. The effects of the TCJA may be subject to changes for items that were previously reported as provisional amounts, as well as any element of the TCJA for which a provisional estimate could not be made, and such changes could be material.

The Company has made provisional computations of the impact of the TCJA as provided for under SAB 118, including transition tax on the mandatory deemed repatriation of foreign earnings and executive compensation limitations under Internal Revenue Code Section 162(m), among others. The Internal Revenue Service is expected to issue additional guidance clarifying provisions of the Act. As additional guidance is issued one or more of the prov isional amounts may change.

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, *Intangibles – Goodwill and Other*. 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 Topic 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

Noncontrolling Interest

We account for noncontrolling interest in accordance with FASB ASC Topic 810, *Consolidation*, which requires the recording of a noncontrolling interest component of Net income (loss), as well as a noncontrolling interest component within equity. Noncontrolling interest represents third-party equity ownership of EEH and is presented as a component of equity in the Consolidated Balance Sheet as of December 31, 2017, as well as an adjustment to Net loss in the Consolidated Statement of Operations for the year ended December 31, 2017.

As of December 31, 2017, Earthstone and Lynden US held 43.3% of the outstanding membership interests in EEH while Bold Holdings, the noncontrolling party, held the remaining 56.7%. See further discussion in *Note 8. Noncontrolling Interest* in the Notes to Consolidated Financial Statements.

Recently Issued Accounting Standards

See *Note 2. Summary of Significant Accounting Policies* in the Notes to Consolidated Financial Statements under Item 8 of this report for a discussion of recently issued 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. Our hedging activities consist of derivative instruments entered into in order to hedge against changes in oil and natural gas prices through the use of fixed price swap agreements. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge.

In connection with the closing of the Bold Transaction on May 9 2017, all oil and natural gas derivative contracts were novated to EEH. We have entered into a series of derivative instruments to hedge a significant portion of our expected oil and natural gas production through December 31, 2019. Typically, these derivative instruments require payments to (receipts from) counterparties based on specific indices as required by the derivative agreements. Although not risk free, we believe these instruments reduce our exposure to oil and natural gas price fluctuations and, thereby, allow us to achieve a more predictable cash flow.

The following is a summary of our open oil and natural gas derivative contracts as of December 31, 2017:

Period	Commodity	Volume (Bbls / MMBtu)		Price ($/Bbl / $/MMBtu)
2018	Crude Oil Swap	1,483,250	$	51.38
2018	Crude Oil Basis Swap (1)	602,250	$	(0.15)
2019	Crude Oil Swap	547,500	$	52.32
2018	Natural Gas Swap	810,000	$	3.066

(1) The basis differential price is between Midland – WTI and the NYMEX – WTI

In January 2018, we entered into additional fixed price oil and natural gas swap agreements, hedging an additional 365,000 Bbls of 2019 oil production at a price of $58.38/Bbl and 1,552,000 MMBtu of 2018 natural gas production at a price of $2.96/MMBtu.

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 net liability position with a fair value of $13.4 million at December 31, 2017. Based on the published commodity futures price curves for the underlying commodity as of December 31, 2017, a 10% increase in per unit commodity prices would cause the total fair value of our commodity derivative financial instruments to decrease by approximately $12.3 million to an overall net liability position of $25.7 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 $11.5 million to an overall net liability position of $1.9 million. There would also be a similar increase or decrease in (Loss) gain on derivative contracts, net in the Consolidated Statements of Operations.

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 based on LIBOR and the prime rate 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, 2017, the outstanding borrowings under the EEH Credit Agreement were $25.0 million bearing interest at rates described in *Note 12. Long-Term Debt* in the Notes to Consolidated Financial Statements. Fluctuations in interest rates will cause our annual interest costs to fluctuate. At December 31, 2017, the interest rate on borrowings under the EEH Credit Agreement was 3.7611% per year. If borrowings at December 31, 2017 were to remain constant, a 10% change in interest rates would impact our future cash flows by approximately $0.1 million per year.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2017, 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 future periods.

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 Disclosure

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 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 reasonable 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 Principal 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, 2017. 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, at the reasonable assurance level, as of December 31, 2017.

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, 2017, 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, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Earthstone Energy, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Earthstone Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, 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) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2017, and our report dated March 15, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion

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 Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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.

Definition and limitations of internal control over financial reporting

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.

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2018

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

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

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

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

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

PART IV

Item 15. Exhibits, Financial Statements 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 among 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		
2.2(a)	First Amendment to the Contribution Agreement dated March 21, 2017, by and among 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	March 23, 2017		
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		
3.1(d)	Third Amended and Restated Certificate of Incorporation of Earthstone Energy, Inc. dated May 9, 2017.	8-A	001-35049	3.1	May 9, 2017		
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
4.3	Specimen Class A Common Stock Certificate of Earthstone Energy, Inc.	8-K	001-35049	4.1	May 15, 2017
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 Agreement 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
10.7(b)†	Second Amendment to the Earthstone Energy, Inc. 2014 Long-Term Incentive Plan dated May 9, 2017.	8-K	001-35049	10.6	May 15, 2017
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
10.16	First Amended and Restated Limited Liability Company Agreement of Earthstone Energy Holdings, LLC dated May 9, 2017.	8-K	001-35049	10.1	May 15, 2017

10.17	Credit Agreement dated May 9, 2017, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, Wells Fargo Bank, National Association as Syndication Agent and the Lenders party thereto.	8-K	001-35049	10.2	May 15, 2017	
10.17(a)	First Amendment to Credit Agreement dated October 11, 2017, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, and Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, and the Lenders party thereto.					X
10.17(b)	Second Amendment to Credit Agreement dated December 1, 2017, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, and Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, and the Lenders party thereto.	8-K	001-35049	10.1	December 4, 2017.	
10.18	Registration Rights Agreement dated May 9, 2017 between Earthstone Energy, Inc. and Bold Energy Holdings, LLC.	8-K	001-35049	10.3	May 15, 2017	
10.19	Voting Agreement dated May 9, 2017 by and among Earthstone Energy, Inc., EnCap Investments L.P., Oak Valley Resources, LLC and Bold Energy Holdings, LLC.	8-K	001-35049	10.4	May 15, 2017	
10.20	Purchase and Sale Agreement dated November 16, 2017, by and between Earthstone Legacy Properties, LLC and Statoil Oil & Gas LP.					X
10.21†	Performance Unit Award Agreement (Executive Management).	8-K	001-35049	10.1	March 2, 2018	
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 Executive Vice President – Accounting and Administration 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.

Item 16. Form 10-K Summary

None.

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.

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

Date: March 15, 2018

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, 2018
/s/ Tony Oviedo Tony Oviedo	Executive Vice President, Accounting and Administration (Principal Financial Officer and Principal Accounting Officer)	March 15, 2018
/s/ Jay F. Joliat Jay F. Joliat	Director	March 15, 2018
/s/ Phil D. Kramer Phil D. Kramer	Director	March 15, 2018
/s/ Ray Singleton Ray Singleton	Director	March 15, 2018
/s/ Wynne M. Snoots, Jr. Wynne M. Snoots, Jr.	Director	March 15, 2018
/s/ Douglas E. Swanson, Jr. Douglas E. Swanson, Jr.	Director	March 15, 2018
/s/ Brad A. Thielemann Brad A. Thielemann	Director	March 15, 2018
/s/ Zachary G. Urban Zachary G. Urban	Director	March 15, 2018
/s/ Robert L. Zorich Robert L. Zorich	Director	March 15, 2018

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.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Earthstone Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, equity, and cash flows for each of the two years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017, 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) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, 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, 2018 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2016.

Houston, Texas
March 15, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Earthstone Energy, Inc.

We have audited the accompanying consolidated statements of operations, equity, and cash flows of Earthstone Energy, Inc. and subsidiaries (formerly Oak Valley Resources, LLC) for the year 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 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 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 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 results of operations and cash flows of Earthstone Energy, Inc. and subsidiaries (formerly Oak Valley Resources, LLC) for the year 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, 2017	December 31, 2016
Current assets:		
Cash	$ 22,955	$ 10,200
Accounts receivable:		
Oil, natural gas, and natural gas liquids revenues	14,978	13,998
Joint interest billings and other, net of allowance of $138 and $163 at December 31, 2017 and 2016, respectively	7,778	2,698
Derivative asset	184	—
Prepaid expenses and other current assets	1,178	446
Total current assets	47,073	27,342
Oil and gas properties, successful efforts method:		
Proved properties	605,039	363,072
Unproved properties	275,025	51,723
Land	5,534	—
Total oil and gas properties	885,598	414,795
Accumulated depreciation, depletion and amortization	(118,028)	(145,393)
Net oil and gas properties	767,570	269,402
Other noncurrent assets:		
Goodwill	17,620	17,620
Office and other equipment, net of accumulated depreciation of $2,093 and $1,600 at December 31, 2017 and 2016, respectively	947	1,479
Other noncurrent assets	1,207	669
TOTAL ASSETS	$ 834,417	$ 316,512
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 33,472	$ 11,927
Revenues and royalties payable	10,288	10,769
Accrued expenses	8,707	5,392
Derivative liability	11,805	4,595
Advances	4,587	4,542
Current portion of long-term debt	—	1,604
Total current liabilities	68,859	38,829
Noncurrent liabilities:		
Long-term debt	25,000	12,693
Asset retirement obligation	2,354	6,013
Derivative liability	1,826	1,575
Deferred tax liability	10,515	15,776
Other noncurrent liabilities	131	169
Total noncurrent liabilities	39,826	36,226
Commitments and Contingencies (Note 15)		
Equity:		
Preferred stock, $0.001 par value, 20,000,000 shares authorized; none issued or outstanding	—	—
Common stock, $0.001 par value, no shares authorized; none issued or outstanding at December 31, 2017 and 100,000,000 shares authorized; 22,289,177 issued and 22,273,820 outstanding at December 31, 2016	—	23
Class A Common stock, $0.001 par value, 200,000,000 shares authorized; 27,584,638 issued and outstanding at December 31, 2017; none issued or outstanding at December 31, 2016	28	—
Class B Common stock, $0.001 par value, 50,000,000 shares authorized; 36,052,169 issued and outstanding at December 31, 2017; none issued or outstanding at December 31, 2016	36	—
Additional paid-in capital	503,932	454,202
Accumulated deficit	(224,822)	(212,308)
Treasury stock, no shares at December 31, 2017 and 15,357 shares at December 31, 2016	—	(460)
Total Earthstone Energy, Inc. equity	279,174	241,457
Noncontrolling interest	446,558	—
Total equity	725,732	241,457
TOTAL LIABILITIES AND EQUITY	$ 834,417	$ 316,512

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, 2017	2016	2015
REVENUES			
Oil	$ 88,536	$ 34,358	$ 39,849
Natural gas	8,777	5,046	5,457
Natural gas liquids	10,765	2,865	2,158
Total revenues	108,078	42,269	47,464
OPERATING COSTS AND EXPENSES			
Lease operating expense	19,658	15,067	15,422
Severance taxes	6,060	2,198	2,582
Rig idle and termination expense	—	5,059	—
Impairment expense	72,191	24,283	138,086
Depreciation, depletion and amortization	36,915	25,937	31,228
General and administrative expense	20,466	9,414	9,711
Stock-based compensation	6,601	3,301	—
Transaction costs	4,732	2,483	589
Accretion of asset retirement obligation	434	551	550
Exploration expense	1	5	142
Total operating costs and expenses	167,058	88,298	198,310
Gain on sale of oil and gas properties	9,105	8	1,617
Loss from operations	**(49,875)**	**(46,021)**	**(149,229)**
OTHER INCOME (EXPENSE)			
Interest expense, net	(2,699)	(1,282)	(722)
Write-off of deferred financing costs	(526)	—	—
(Loss) gain on derivative contracts, net	(7,986)	(6,638)	6,431
Other (expense) income, net	(20)	(72)	423
Total other income (expense)	(11,231)	(7,992)	6,132
Loss before income taxes	(61,106)	(54,013)	(143,097)
Income tax benefit (expense)	16,373	(528)	26,442
Net loss	(44,733)	(54,541)	(116,655)
Less: Net loss attributable to noncontrolling interest	(32,219)	—	—
Net loss attributable to Earthstone Energy, Inc.	$ (12,514)	$ (54,541)	$ (116,655)
Net loss per common share attributable to Earthstone Energy, Inc.:			
Basic and diluted	$ (0.53)	$ (2.92)	$ (8.43)
Weighted average common shares outstanding:			
Basic and diluted	23,589,973	18,651,582	13,835,128

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

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

	Issued Shares											
	Common Stock	Class A Common Stock	Class B Common Stock	Common Stock	Class A Common Stock	Class B Common Stock	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Earthstone Energy, Inc. Stockholders' Equity	Noncontrolling Interest	Total Equity
At December 31, 2014	13,835,128	—	—	$ 14	$ —	$ —	$ 358,086	$ (41,112)	$ (460)	$ 316,528	$ —	$ 316,528
Net loss	—	—	—	—	—	—	—	(116,655)	—	(116,655)	—	(116,655)
At December 31, 2015	13,835,128	—	—	14	—	—	358,086	(157,767)	(460)	199,873	—	199,873
Stock-based compensation expense	—	—	—	—	—	—	3,301	—	—	3,301	—	3,301
Common stock issued, net of offering costs of $2.7 million	4,753,770	—	—	5	—	—	47,120	—	—	47,125	—	47,125
Shares issued in Lynden Arrangement	3,700,279	—	—	4	—	—	45,695	—	—	45,699	—	45,699
Net loss	—	—	—	—	—	—	—	(54,541)	—	(54,541)	—	(54,541)
At December 31, 2016	22,289,177	—	—	23	—	—	454,202	(212,308)	(460)	241,457	—	241,457
Stock-based compensation expense	—	—	—	—	—	—	6,601	—	—	6,601	—	6,601
Vesting of restricted stock units prior to completion of Bold Contribution Agreement	382,804	—	—	—	—	—	(1)	—	—	(1)		(1)
Common stock exchanged in connection with Bold Contribution Agreement	(22,656,624)	22,656,624	—	(23)	23	—	—	—	—	—	—	—
Treasury shares converted to Class A Common Stock	(15,357)	15,357	—	—	—	—	—	—	—	—	—	—
Closing of Bold Contribution Agreement	—	150,000	—	—	—	—	12,872	—		12,872	479,007	491,879
Class B Common Stock sold in connection with Bold Contribution Agreement	—	—	36,070,828	—	—	36	—	—	—	36	—	36
Deferred tax consequences of Bold Contribution Agreement	—	—	—	—	—	—	(8,270)	—	—	(8,270)	—	(8,270)
Vesting of restricted stock units following completion of Bold Contribution Agreement	—	259,355	—	—	—	—	—	—	—	—	—	—
Class A Common Stock retained by the Company in exchange for payment of recipient mandatory tax withholdings	—	61,055	—	—	—	—	(675)	—	—	(675)	—	(675)
Cancellation of treasury shares	—	(76,412)	—	—	—	—	(460)	—	460	—	—	—
Class A Common Stock issued, net of offering costs of $2.2 million	—	4,500,000	—	—	5	—	39,433	—	—	39,438	—	39,438
Class B Common Stock converted to Class A Common Stock	—	18,659	(18,659)	—	—	—	230	—	—	230	(230)	—
Net loss	—	—	—	—	—	—	—	(12,514)	—	(12,514)	(32,219)	(44,733)
At December 31, 2017	—	27,584,638	36,052,169	$ —	$ 28	$ 36	$ 503,932	$ (224,822)	$ —	$ 279,174	$ 446,558	$ 725,732

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,		
	2017	2016	2015
Cash flows from operating activities:			
Net loss	$ (44,733)	$ (54,541)	$ (116,655)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Impairment of proved and unproved oil and gas properties	72,191	6,751	136,539
Depreciation, depletion and amortization	36,915	25,937	31,228
Accretion of asset retirement obligations	434	551	550
Impairment of goodwill	—	17,532	1,547
Gain on sale of oil and gas properties	(9,105)	(8)	(1,617)
Settlement of asset retirement obligations	(9)	(15)	(108)
Rig idle and termination expense	—	5,059	—
Total loss (gain) on derivative contracts, net	7,986	6,638	(6,431)
Operating portion of net cash (paid) received in settlement of derivative contracts	(708)	3,225	6,306
Stock-based compensation	6,601	3,301	—
Deferred income taxes	(16,388)	528	(26,533)
Write-off of deferred financing costs	526	—	—
Amortization of deferred financing costs	257	298	264
Changes in assets and liabilities:			
Decrease in accounts receivable	444	3,807	9,246
(Increase) decrease in prepaid expenses and other current assets	(335)	511	779
Decrease in accounts payable and accrued expenses	(282)	(9,151)	(30,887)
(Decrease) increase in revenues and royalties payable	(2,888)	2,194	(8,739)
Increase (decrease) in advances	45	(10,905)	(5,929)
Net cash provided by (used in) operating activities	50,951	1,712	(10,440)
Cash flows from investing activities:			
Lynden Arrangement, net of cash acquired	—	(31,334)	—
Acquisition of oil and gas properties	(55,609)	—	(8,706)
Additions to oil and gas properties	(65,262)	(28,417)	(61,060)
Additions to office and other equipment	(167)	(117)	(378)
Proceeds from sale of oil and gas properties	34,735	—	3,441
Proceeds from sale of land	—	—	101
Net cash used in investing activities	(86,303)	(59,868)	(66,602)
Cash flows from financing activities:			
Proceeds from borrowings	85,000	36,597	—
Repayments of borrowings	(74,298)	(38,549)	—
Cash paid related to the exchange and cancelation of Common Stock	(675)	—	—
Deferred financing costs	(1,358)	(81)	(141)
Issuance of Class A Common Stock and Common Stock, net of offering costs of $2.2 million and $2.7 million, respectively	39,438	47,125	—
Net cash provided by (used in) financing activities	48,107	45,092	(141)
Net increase (decrease) in cash and cash equivalents	12,755	(13,064)	(77,183)
Cash at beginning of period	10,200	23,264	100,447
Cash at end of period	$ 22,955	$ 10,200	$ 23,264
Supplemental disclosure of cash flow information			
Cash paid for:			
Interest	$ 2,495	$ 961	$ 415
Non-cash investing and financing activities:			
Class B Common Stock issued in Bold Contribution Agreement	$ 489,842	$ —	$ —
Class A Common Stock issued in Bold Contribution Agreement	$ 2,037	$ —	$ —
Common stock issued in Lynden Arrangement	$ —	$ 45,699	$ —
Accrued capital expenditures	$ 19,883	$ 2,374	$ 7,665
Asset retirement obligations	$ (42)	$ 152	$ 150
Promissory Note	$ —	$ 5,059	$ —
Acquisition of oil and gas properties	$ —	$ —	$ 1,991

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

Note 1. – Organization and Basis of Presentation

Earthstone Energy, Inc., a Delaware corporation ("Earthstone" and together with its consolidated subsidiaries, the "Company"), 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. The Company's operations are all in the up-stream segment of the oil and natural gas industry and all its properties are onshore in the United States.

Earthstone is the sole managing member of Earthstone Energy Holdings, LLC, a Delaware limited liability company (together with its wholly-owned consolidated subsidiaries, "EEH"), with a controlling interest in EEH. Earthstone, together with its wholly-owned subsidiary, Lynden Energy Corp., a corporation organized under the laws of British Columbia ("Lynden Corp"), and Lynden Corp's wholly-owned consolidated subsidiary, Lynden USA Inc., a Utah corporation ("Lynden US") and also a member of EEH, consolidates the financial results of EEH and records a noncontrolling interest in the Consolidated Financial Statements representing the economic interests of EEH's members other than Earthstone and Lynden US.

Certain prior period amounts have been reclassified to conform to current period presentation within the Consolidated Financial Statements. Prior period Re-engineering and workovers in the Consolidated Statements of Operations have been reclassified from its own line item and included in Lease operating expenses, within Operating Costs and Expenses, to conform to current period presentation. This reclassification had no effect on Loss from operations or any other subtotal in the Consolidated Statements of Operations.

Bold Contribution Agreement

On May 9, 2017, Earthstone completed a contribution agreement dated as of November 7, 2016 and as amended on March 21, 2017 (the "Bold Contribution Agreement"), by and among Earthstone, EEH, Lynden US, Lynden USA Operating, LLC, a Texas limited liability company ("Lynden Op"), Bold Energy Holdings, LLC, a Texas limited liability company ("Bold Holdings"), and Bold Energy III LLC, a Texas limited liability company ("Bold"). The purpose of the Bold Contribution Agreement was to provide for, among other things described below, the business combination between Earthstone and Bold, which owned significant developed and undeveloped oil and natural gas properties in the Midland Basin of Texas (the "Bold Transaction").

The Bold Transaction was structured in a manner commonly known as an "Up-C." Under this structure and the Bold Contribution Agreement, (i) Earthstone recapitalized its common stock into two classes – Class A common stock, $0.001 par value per share (the "Class A Common Stock"), and Class B common stock, $0.001 par value per share (the "Class B Common Stock"), and all of Earthstone's existing outstanding common stock, $0.001 par value per share (the "Common Stock"), was recapitalized on a one-for-one basis for Class A Common Stock (the "Recapitalization"); (ii) Earthstone transferred all of its membership interests in Earthstone Operating, LLC, Sabine River Energy, LLC, EF Non-Op, LLC and Earthstone Legacy Properties, LLC (formerly Earthstone GP, LLC) and $36,071 in cash from the sale of Class B Common Stock to Bold Holdings (collectively, the "Earthstone Assets") to EEH, in exchange for 16,791,296 membership units of EEH (the "EEH Units"); (iii) Lynden US transferred all of its membership interests in Lynden Op to EEH in exchange for 5,865,328 EEH Units; (iv) Bold Holdings transferred all of its membership interests in Bold to EEH in exchange for 36,070,828 EEH Units and purchased 36,070,828 shares of Class B Common Stock issued by Earthstone for $36,071; and (v) Earthstone granted an aggregate of 150,000 fully vested shares of Class A Common Stock under Earthstone's 2014 Long-Term Incentive Plan, as amended (the "2014 Plan"), to certain employees of Bold. Each EEH Unit, together with one share of Class B Common Stock, are convertible into one share of Class A Common Stock.

Upon closing of the Bold Transaction on May 9, 2017, Bold Holdings owned approximately 61.4% of the outstanding shares of Class A Common Stock, on a fully diluted, as converted basis. The EEH Units and the shares of Class B Common Stock issued to Bold Holdings were not registered under the Securities Act of 1933, as amended (the "Securities Act"), but were issued by EEH and Earthstone in reliance on the exemption provided under Section 4(a)(2) of the Securities Act.

On May 9, 2017, the closing sale price of the Class A Common Stock was $13.58 per share. On May 10, 2017, the Class A Common Stock was uplisted from the NYSE American, LLC (formerly the NYSE MKT) (the "NYSE American") to the New York Stock Exchange (the "NYSE") where it is listed under the symbol "ESTE."

On May 9, 2017, in connection with the closing of the Bold Transaction, Earthstone, EnCap Investments L.P. ("EnCap"), Oak Valley Resources, LLC ("OVR"), and Bold Holdings entered into a voting agreement (the "Voting Agreement"), pursuant to which EnCap, OVR, and Bold Holdings agreed not to vote any shares of Class A Common Stock or Class B Common Stock held by them in favor of any action, or take any action that would in any way alter the composition of the board of directors of Earthstone (the "Board") from its composition immediately following the closing of the Bold Transaction as long as the Voting Agreement is in effect. The Voting Agreement terminates on the earlier of (i) the fifth anniversary of the closing date of the Bold Contribution Agreement and (ii) the date upon which EnCap, OVR and Bold Holdings collectively own, of record and beneficially, less than 20% of Earthstone's outstanding voting stock.

Pursuant to the terms of the Bold Contribution Agreement, at the closing of the Bold Transaction, Earthstone, Bold Holdings, and the unitholders of Bold Holdings entered into a registration rights agreement (the "Registration Rights Agreement") relating to the shares of Class A Common Stock issuable upon the exchange of the EEH Units and Class B Common Stock held by Bold Holdings or its unitholders. In accordance with the Registration Rights Agreement, Earthstone filed a registration statement (the "Registration Statement") with the Securities and Exchange Commission (the "SEC") to permit the public resale of the shares of Class A Common Stock issued by Earthstone to Bold Holdings or its unitholders in connection with the exchange of Class B Common Stock and EEH Units in accordance with the terms of the First Amended and Restated Limited Liability Company Agreement of EEH (the "EEH LLC Agreement"). On October 18, 2017, the Registration Statement was declared effective by the SEC.

The Bold Transaction was recorded in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 805, Business Combinations, and is consolidated in these financial statements in accordance with FASB ASC Topic 810, Consolidation, which requires the recording of a noncontrolling interest component of net income (loss), as well as a noncontrolling interest component within equity, including changes to additional paid-in capital to reflect the noncontrolling interest within equity in the Consolidated Balance Sheet as of December 31, 2017 at the noncontrolling interest's respective membership interest in EEH.

Note 2. – Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts and balances of the Company 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, asset 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 $0.1 million at and $0.2 million at December 31, 2017 and 2016, respectively.

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 mark-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 Natural 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. The Company uses the successful efforts method of accounting for oil and natural gas properties as prescribed 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. There were no impairments to Goodwill recorded in the year ended December 31, 2017. During the years ended December 31, 2016 and 2015, impairments to Goodwill of $17.5 million and $1.5 million, respectively, were recorded. For further discussion, see *Note 7. Goodwill*.

Noncontrolling Interest

Noncontrolling Interest represents third-party equity ownership of EEH and is presented as a component of equity in the Consolidated Balance Sheet as of December 31, 2017, as well as an adjustment to Net loss in the Consolidated Statement of Operations for the year ended December 31, 2017. As of December 31, 2017, Earthstone and Lynden US owned a 43.3% membership interest in EEH while Bold Holdings, the noncontrolling third party, owned the remaining 56.7%. See further discussion in *Note 8. Noncontrolling Interest*.

Segment Reporting

Operating segments are defined under FASB ASC Topic 280, Segment Reporting, as components of an enterprise that (i) engage in activities from which it may earn revenues and incur expenses (ii) for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on our organization and management, we have only one reportable operating segment, which is oil and natural gas exploration and production. We consider drilling rig services ancillary to our oil and natural gas exploration and producing activities and manage these services to support such activities.

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 13. 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, 2017, 2016, or 2015.

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 2017, three purchasers accounted for 18%, 14% and 14%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. In 2016, two purchasers accounted for 41% and 19%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. In 2015, one purchaser accounted for 62% 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 2017, 2016, and 2015. Additionally, at December 31, 2017, three purchasers accounted for 20%, 13% and 12%, respectively, of the Company's oil, natural gas and natural gas liquids receivables. At December 31, 2016, two purchasers accounted for 28% and 12%, respectively, 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, 2017 and 2016.

The Company holds working interests in oil and natural 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. In 2017, 2016 and 2015, one operator distributed 10%, 19% and 12%, respectively, 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 2017, 2016, and 2015.

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, 2017 and 2016, the Company had no derivative contracts that were in a material asset position.

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

The Company is a U.S. company operating primarily in Texas, as of December 31, 2017, as well as one foreign legal entity, Lynden Corp, which is a Canadian company. Consequently, the Company's tax provision is based upon the tax laws and rates in effect in the applicable jurisdiction in which its 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, the Company is 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. The Company's effective tax rate for financial statement purposes will continue to fluctuate from year to year as its operations are conducted in different taxing jurisdictions.

Following the closing of the Bold Transaction, the Company continues to record an income tax provision consistent with its status as a corporation. The Company's corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns and one Canadian income tax return resulting from Earthstone's acquisition of Lynden Corp in May 2016 (the "Lynden Arrangement") that includes Lynden US, Earthstone, and Lynden Corp. 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 be offset by tax attributes of Earthstone. Following the Bold Transaction, Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the noncontrolling interest, as well as any standalone income or loss generated by each company. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

The Company's deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported in the 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, 2017 and 2016, the Company has recorded a valuation allowance for its deferred tax assets in the Consolidated Balance Sheets.

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 and 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, 2017, 2016 or 2015.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the Tax Cuts and Jobs Act (the "TCJA"), resulting in significant modifications to existing law. Our consolidated financial statements for the year ended December 31, 2017, reflect certain effects of the TCJA, which includes the federal corporate income tax rate reduction to 21%. Consistent with Staff Accounting Bulletin No. 118 issued by the SEC, which provides for a measurement period of one year from the enactment date to finalize the accounting for effects of the TCJA, the Company provisionally recorded income tax expense of $7.8 million related to the TCJA. In accordance with SEC guidance, provisional amounts may be refined as a result of additional guidance from, and interpretations by, U.S. regulatory and standard-setting bodies, and changes in assumptions. In the subsequent period, provisional amounts will be adjusted for the effects, if any, of interpretative guidance issued after December 31, 2017, by the U.S. Department of the Treasury. The effects of the TCJA may be subject to changes for items that were previously reported as provisional amounts, as well as any element of the TCJA for which a provisional estimate could not be made, and such changes could be material.

The Company has made provisional computations of the impact of the TCJA as provided for under SAB 118, including transition tax on the mandatory deemed repatriation of foreign earnings and executive compensation limitations under Internal Revenue Code Section 162(m), among others. The Internal Revenue Service is expected to issue additional guidance clarifying provisions of the Act. As additional guidance is issued one or more of the provisional amounts may change.

Recently Issued Accounting Standards

Accounting for the Tax Cuts and Jobs Act – In December 2017, the SEC Staff issued Staff Accounting Bulletin No. 118, *Income Tax Accounting Implications of the TCJA* ("SAB 118"), to supplement the accounting requirements of FASB ASC Topic 740, *Income Taxes* (ASC Topic 740), as it relates to assessing and recognizing the impacts of the TCJA in the period of enactment. SAB 118 allows an entity to recognize provisional amounts in its financial statements in circumstances in which the entity's assessment is incomplete, but for which a reasonable estimate can be made. Provisional amounts recognized are subject to adjustment for up to one year from the enactment date.

In the fourth quarter of 2017, the Company remeasured its deferred taxes at 21%, in accordance with the TCJA and GAAP.

For further details, see *Note 16. Income Taxes* to the Consolidated Financial Statements.

Revenue Recognition - In May 2014, the FASB issued updated guidance for recognizing revenue from contracts with customers, which seeks to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. This new revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The two permitted transition methods under the new standard are the full retrospective method, in which case the standard would be applied to each prior reporting period presented, or the modified retrospective method, in which case the cumulative effect of applying the standard would be recognized at the date of initial application. The new standard is now effective prospectively for reporting periods beginning on or after December 15, 2017. The Company has completed its evaluation of the new standard and will adopt the new standard, as required, beginning with the first quarter of 2018, and does not expect the adoption to have a material impact on its Consolidated Financial Statements. The Company has elected to use the modified retrospective method for adoption and has updated its related internal control documentation, processes and controls to conform to the new standard.

Leases – In February 2016, the FASB issued updated guidance on accounting for leases. The update requires that a lessee recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election by class of underlying asset not to recognize lease assets and lease liabilities. Similar to current guidance, the update continues to differentiate between finance leases and operating leases; however, this distinction now primarily relates to differences in the manner of expense recognition over time and in the classification of lease payments in the statement of cash flows. The standards update is effective for interim and annual periods beginning after December 15, 2018 with early adoption permitted. 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 expects to adopt this standards update, as required, beginning with the first quarter of 2019. The Company is in the process of evaluating the impact, if any, of the adoption of this guidance on its Consolidated Financial Statements.

Statement of Cash Flows – In August 2016, the FASB issued updated guidance that clarifies how certain cash receipts and cash payments are presented in the statement of cash flows. This update provides guidance on eight specific cash flow issues. The standards update is effective for interim and annual periods beginning after December 15, 2017, and should be applied retrospectively to all periods presented. The Company will adopt this update, as required, beginning with the first quarter of 2018, and does not expect the adoption to have a material impact on its Consolidated Statements of Cash Flows.

Business Combinations – In January 2017, the FASB issued updated guidance that clarifies the definition of a business, which amends the guidance used in evaluating whether a set of acquired assets and activities represents a business. The guidance requires an entity to evaluate if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets; if so, the set of transferred assets and activities is not considered a business. As a result, acquisition fees and expenses will be capitalized to the cost basis of the property acquired, and the tangible and intangible components acquired will be recorded based on their relative fair values as of the acquisition date. The standard is effective for all public business entities for annual periods beginning after December 15, 2017. The Company will adopt this update, as required, beginning with the first quarter of 2018, and does not expect the adoption to have a material impact on its Consolidated Financial Statements.

Intangibles - Goodwill and Other – In January 2017, the FASB issued updated guidance simplifying the test for goodwill impairment. The update eliminates Step 2 of the goodwill impairment test. Instead, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The update is effective for annual and interim periods beginning after December 15, 2019 and early adoption is permitted for interim or annual goodwill impairment tests performed after January 1, 2017. The Company is in the process of evaluating the impact, if any, on its Consolidated Financial Statements.

Compensation – Stock Compensation – In May 2017, the FASB issued updated guidance that provides clarity about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. The update is effective for annual periods beginning after December 15, 2017. The Company will adopt this update, as required, beginning with the first quarter of 2018, and does not expect the adoption to have a material impact on its Consolidated Financial Statements.

Note 3. Acquisitions and Divestitures

The Company accounts for its acquisitions that qualify as business combinations, under the acquisition method of accounting 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. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as additional information is obtained about the facts and circumstances that existed as of the acquisition dates.

Bold Transaction

On May 9, 2017, Earthstone completed the Bold Transaction described in *Note 1. Organization and Basis of Presentation*.

An allocation of the purchase price was prepared using, among other things, a reserve report prepared by qualified reserve engineers and priced as of the acquisition date. The following allocation is still preliminary with respect to final tax amounts and certain accruals and includes the use of estimates based on information that was available to management at the time these Consolidated Financial Statements were prepared.

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

Consideration:		
Shares of Class A Common Stock issued pursuant to the Bold Contribution Agreement to certain employees of Bold		150,000
EEH Units issued to Bold Holdings		36,070,828
Total equity interest issued in the Bold Transaction		36,220,828
Closing per share price of Class A Common Stock as of May 9, 2017	$	13.58
Total consideration transferred (1) (2)	$	491,879
Fair value of assets acquired:		
Cash and cash equivalents	$	2,355
Other current assets		10,078
Oil and gas properties (3)		557,704
Amount attributable to assets acquired	$	570,137
Fair value of liabilities assumed:		
Long-term debt (4)	$	58,000
Current liabilities		17,042
Deferred tax liability		2,857
Noncurrent asset retirement obligations		359
Amount attributable to liabilities assumed	$	78,258

(1) Consideration included 150,000 shares of Class A Common Stock recorded above based upon its fair value which was determined using the closing price of $13.58 per share on May 9, 2017.

(2) Consideration was 36,070,828 EEH Units. Additionally, Bold Holdings purchased 36,070,828 shares of Class B Common Stock for $36,071. Each EEH Unit, together with one share of Class B Common Stock, is convertible into one share of Class A Common Stock. The fair value of the consideration was determined using the closing price of the Company's Class A Common Stock of $13.58 per share on May 9, 2017.

(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, projections 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 3. Fair Value Measurements*, below.

(4) Concurrent with the closing of the Bold Transaction, EEH repaid Bold's outstanding borrowings of $58.0 million under its credit agreement.

The following unaudited supplemental pro forma condensed results of operations present consolidated information as though the Bold Transaction and the Bakken Sale (discussed below) had been completed as of January 1, 2016. The unaudited supplemental pro forma financial information was derived from the historical consolidated and combined statements of operations for Bold and Earthstone and adjusted to include: (i) depletion expense applied to the adjusted basis of the properties acquired and (ii) to eliminate non-recurring transaction costs directly related to the Bold Transaction that do not have a continuing impact on the Company's operating results. 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,	
	2017	2016
	(Unaudited)	
Revenue	$ 126,839	$ 54,436
Loss before taxes	$ (44,461)	$ (40,564)
Net loss	$ (35,617)	$ (41,092)
Less: Net loss attributable to noncontrolling interest	$ (22,005)	$ (27,012)
Net loss attributable to Earthstone Energy, Inc.	$ (13,612)	$ (14,080)
Pro forma net loss per common share attributable to Earthstone Energy, Inc.:		
Basic and Diluted	$ (0.57)	$ (0.75)

The Company has included in its Consolidated Statements of Operations, revenues of $50.2 million and direct operating expenses of $23.8 million for the period from May 9, 2017 to December 31, 2017 related to the properties acquired in the Bold Transaction.

Divestitures

On December 20, 2017, the Company sold all of its oil and natural gas leases, oil and natural gas wells and associated assets located in the Williston Basin in North Dakota (the "Bakken Sale") for a net cash consideration of approximately $26.4 million after normal and customary purchase price adjustments of $0.9 million to account for net cash flows from the effective date to the closing date. The sale resulted in a net gain of approximately $3.0 million recorded in Gain on sale of oil and gas properties in the Consolidated Statements of Operations. The effective date of the sale was December 1, 2017.

For the year ended December 31, 2017, the Company sold certain non-core properties for a total cash consideration of approximately $7.5 million, while eliminating approximately $4.0 million of future abandonment obligations. The sales resulted in a net gain of approximately $6.1 million recorded in Gain on sale of oil and gas properties in the Consolidated Statements of Operations.

In April 2015, the Company sold its Louisiana properties located primarily in DeSoto and Caddo Parishes, for cash consideration of approximately $3.4 million. The sale resulted in a net gain of $1.6 million recorded in Gain on sale of oil and gas properties in the Consolidated Statements of Operations. 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 Topic 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 Topic 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, 2017.

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, 2017	Level 1	Level 2	Level 3	Total
Financial assets				
Derivative asset- current	$ —	$ 184	$ —	$ 184
Total financial assets	$ —	$ 184	$ —	$ 184
Financial liabilities				
Derivative liability - current	$ —	$ 11,805	$ —	$ 11,805
Derivative liability - noncurrent	—	1,826	—	1,826
Total financial liabilities	$ —	$ 13,631	$ —	$ 13,631
December 31, 2016				
Financial liabilities				
Derivative liability - current	$ —	$ 4,595	$ —	$ 4,595
Derivative liability - noncurrent	—	1,575	—	1,575
Total financial liabilities	$ —	$ 6,170	$ —	$ 6,170

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.

Proved Oil and Natural Gas Properties

Proved oil and natural gas properties are measured at fair value on a nonrecurring basis in order to review for impairment. The impairment charge reduces the carrying values 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 natural 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 fair value of goodwill may be less than its carrying amount. 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 natural 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 13 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

In connection with the closing of the Bold Transaction on May 9, 2017, all oil and natural gas derivative contracts were novated to EEH. The Company's hedging activities consist of derivative instruments entered into in order to hedge against changes in oil and natural gas prices through the use of fixed price swaps and basis swaps agreements. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Consistent with its hedging policy, the Company has entered into a series of derivative instruments to hedge a significant portion of its expected oil and natural gas production through December 31, 2019. Typically, these derivative instruments require payments to (receipts from) counterparties based on specific indices as required by the derivative agreements. Although not risk free, the Company believes these instruments reduce its exposure to oil and natural gas price fluctuations and, thereby, allow the Company to achieve a more predictable cash flow.

The Company's derivative instruments are cash flow hedge transactions in which it is hedging the variability of cash flow related to a forecasted transaction. The Company does not enter into derivative instruments for trading or other speculative purposes. These transactions are recorded in the Consolidated Financial Statements in accordance with FASB ASC Topic 815. The Company has accounted for these transactions using the mark-to-market accounting method. Generally, the Company incurs accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in the Consolidated Balance Sheets and Consolidated Statements of Operations.

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 following table sets forth the Company's outstanding derivative contracts at December 31, 2017. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)	
2018	Crude Oil Swap	1,483,250	$	51.38
2018	Crude Oil Basis Swap (1)	602,250	$	(0.15)
2019	Crude Oil Swap	547,500	$	52.32
2018	Natural Gas Swap	810,000	$	3.066

(1) The basis differential price is between Midland – West Texas Intermediate ("WTI") and the NYMEX – WTI

In January 2018, the Company entered into additional fixed price oil and natural gas swap agreements, hedging an additional 365,000 Bbls of 2019 oil production at a price of $58.38/Bbl and 1,552,000 MMBtu of 2018 natural gas production at a price of $2.96/MMBtu.

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, 2017			December 31, 2016		
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 - current	$ 184	$ —	$ 184	$ —	$ —	$ —
Commodity contracts	Derivative liability - current	$ 11,805	$ —	$ 11,805	$ 4,595	$ —	$ 4,595
Commodity contracts	Derivative liability - noncurrent	$ 1,826	$ —	$ 1,826	$ 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	2017	2016	2015
Total (loss) gain on commodity contracts	(Loss) gain on derivative contracts, net	$ (7,278)	$ (9,863)	$ 125
Cash settlements on commodity contracts	(Loss) gain on derivative contracts, net	(708)	3,225	6,306
(Loss) gain on commodity contracts, net		$ (7,986)	$ (6,638)	$ 6,431

Note 6. Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its oil and natural gas properties. Under this method, costs to acquire oil and natural 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 natural 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 natural 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 natural gas producing property and related equipment was $36.4 million, $25.4 million, and $30.7 million, for the years ended December 31, 2017, 2016, and 2015, respectively.

Proved Properties

Proved oil and natural gas properties are measured at fair value on a nonrecurring basis in order to review for impairment. The impairment charge reduces the carrying values 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 natural 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.

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 natural 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 presence 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, 2017, 2016 and 2015 (*in thousands*):

	Years Ended December 31,		
	2017	2016	2015
Proved property	$ 63,131	$ 2,873	$ 93,984
Unproved property	9,060	3,878	42,555
Total	$ 72,191	$ 6,751	$ 136,539

Accumulated impairments to proved and unproved oil and natural gas properties as of December 31, 2017 and 2016, were $148.2 million and $162.7 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 did not have any non-cash impairment charges to its goodwill for the year ended December 31, 2017. 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

Accumulated impairments to Goodwill as of December 31, 2017 and 2016, were $19.1 million.

Note 8. Noncontrolling Interest

As a result of the Bold Transaction, Earthstone became the sole managing member of, and has a controlling interest in, EEH. As the sole managing member of EEH, Earthstone operates and controls all of the business and affairs of EEH and its subsidiaries. Immediately following the Bold Transaction, Earthstone and Lynden US owned a 38.6% membership interest in EEH while Bold Holdings owned the remaining 61.4%.

The Bold Transaction was recorded in accordance with FASB ASC Topic 805, Business Combinations, and is consolidated in these financial statements in accordance with FASB ASC Topic 810, Consolidation, which requires the recording of a noncontrolling interest component of net income (loss), as well as a noncontrolling interest component within equity, including changes to Additional paid-in capital to reflect the noncontrolling interest within equity in the Consolidated Balance Sheet as of December 31, 2017 at the noncontrolling interest's respective membership interest in EEH. A reconciliation of the equity attributable to the noncontrolling interest as of May 9, 2017 is as follows (*in thousands*):

Total considerations transferred (1)	$ 491,879
Change to additional paid-in capital to reflect the noncontrolling interest within equity at their membership interest	(12,872)
Portion of equity attributable to noncontrolling interest (2)	$ 479,007

(1) See *Note 3. Acquisitions and Divestitures*.
(2) Represents 61.4% of total equity attributable to EEH as of May 9, 2017.

Earthstone consolidates the financial results of EEH and its subsidiaries, and records a noncontrolling interest for the economic interest in Earthstone held by the members of EEH other than Earthstone and Lynden US. Net loss attributable to noncontrolling interest in the Consolidated Statements of Operations for the year ended December 31, 2017 represents the portion of net income or loss attributable to the economic interest in the Company held by the members of EEH other than Earthstone and Lynden US. Noncontrolling interest in the Consolidated Balance Sheet as of December 31, 2017 represents the portion of net assets of the Company attributable to the members of EEH other than Earthstone and Lynden US.

The following table presents the changes in noncontrolling interest for the year ended December 31, 2017:

	EEH Units Held By Earthstone and Lynden US	%	EEH Units Held By Others	%	Total EEH Units Outstanding
As of December 31, 2016	—	—	—	—	—
May 9, 2017 - Bold Transaction	22,656,624	38.6%	36,070,828	61.4%	58,727,452
EEH Units issued in connection with Class A Common Stock issued in connection with the Bold Transaction	150,000		—		150,000
EEH Units issued in connection with the vesting of restricted stock units and issuance of Class A Common Stock	259,355		—		259,355
EEH Units issued in connection with Class A Common Stock offering	4,500,000		—		4,500,000
EEH Units and Class B Common Stock converted to Class A Common Stock	18,659		(18,659)		-
As of December 31, 2017	27,584,638	43.3%	36,052,169	56.7%	63,636,807

The following table summarizes the activity for the equity attributable to the noncontrolling interest for the year ended December 31, 2017 (*in thousands*):

		2017
As of December 31, 2016	$	—
Noncontrolling interest recorded within equity in connection with the closing of the Bold Transaction		479,007
EEH Units and Class B Common Stock converted to Class A Common Stock		(230)
Net loss attributable to noncontrolling interest		(32,219)
As of December 31, 2017	$	446,558

Note 9. 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 (Common Stock through May 8, 2017 and Class A Common Stock from May 9, 2017 through December 31, 2017). 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, as defined above, 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, as defined above, would have an anti-dilutive effect.

A reconciliation of Net loss per common share is as follows:

	Years Ended December 31,		
(In thousands, except per share amounts)	2017	2016	2015
Net loss attributable to Earthstone Energy, Inc.	$ (12,514)	$ (54,541)	$ (116,655)
Net loss per common share attributable to Earthstone Energy, Inc.:			
Basic	$ (0.53)	$ (2.92)	$ (8.43)
Diluted	$ (0.53)	$ (2.92)	$ (8.43)
Weighted average common shares outstanding			
Basic	23,589,973	18,651,582	13,835,128
Add potentially dilutive securities:			
Unvested restricted stock units	—	—	—
Diluted weighted average common shares outstanding	23,589,973	18,651,582	13,835,128

Class B Common Stock has been excluded, as its conversion would eliminate noncontrolling interest and Net loss attributable to noncontrolling interest of $32.2 million would be added back to Net loss attributable to Earthstone Energy, Inc., having no dilutive effect on Net loss per common share attributable to Earthstone Energy, Inc. For the years ended December 31, 2017 and 2016, the Company excluded 105,422 and 52,844 shares, respectively, 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 these periods. For the year ended December 31, 2015, there were no restricted stock units issued or outstanding under the 2014 Plan.

Note 10. Common Stock

On May 9, 2017, and in connection with the completion of the Bold Transaction, Earthstone recapitalized its Common Stock into two classes, as described in *Note 1. Organization and Basis of Presentation*, Class A Common Stock and Class B Common Stock. At that time, all of Earthstone's existing outstanding Common Stock was automatically converted on a one-for-one basis into Class A Common Stock.

Class A Common Stock

At December 31, 2017, there were 27,584,638 shares of Class A Common Stock issued and outstanding. On July 1, 2017, Earthstone retired and returned the 15,357 shares of treasury stock to authorized but unissued shares of Class A Common Stock. During the period January 1, 2017 through May 8, 2017, the Company issued 382,804 shares of Common Stock as a result of the vesting and settlement of restricted stock units under the 2014 Plan. During the period May 9, 2017 through December 31, 2017, the Company issued 320,410 shares of Class A Common Stock as a result of the vesting and settlement of restricted stock units under the 2014 Plan, of which 61,055 shares of Class A Common Stock were withheld by the Company in exchange for payment of income tax withholdings. Additionally, on May 9, 2017, under the Bold Contribution Agreement, Earthstone issued 150,000 shares of Class A Common Stock valued at approximately $2.0 million on that date. For additional information, see *Note 3. Acquisitions and Divestitures*.

Class A Common Stock Offering

In October 2017, Earthstone completed a public offering of 4,500,000 shares of Class A Common Stock, at an issue price of $9.25 per share. Earthstone received net proceeds from this offering of $39.4 million, after deducting underwriters' fees and offering expenses of $2.2 million. The net proceeds from the offering were used to repay outstanding indebtedness under the EEH Credit Agreement, as described in *Note 12. Long-Term Debt*.

Class B Common Stock

At December 31, 2017, there were 36,052,169 shares of Class B Common Stock issued and outstanding. On May 9, 2017, in connection with Earthstone's completion of the Bold Transaction, Earthstone issued 36,070,828 shares of Class B Common Stock in exchange for $36 thousand. Each share of Class B Common Stock, together with one EEH Unit, is convertible into one share of Class A Common Stock. Earthstone did not have any Class B Common Stock issued at December 31, 2016. For additional information, see *Note 3. Acquisitions and Divestitures*. Additionally, subsequent to the completion of the Bold Transaction, 18,659 shares of Class B Common Stock were exchanged, along with 18,659 EEH Units, for 18,659 shares of Class A Common Stock.

Common Stock

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

- On May 18, 2016, the Company acquired Lynden Corp 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 Corp.
- In June 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.

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

Note 11. Stock Based Compensation

The 2014 Plan allows, among other things, for the grant of restricted stock units ("RSUs"). On May 9, 2017, and in connection with the completion of the Bold Contribution Agreement, and upon approval by the stockholders of Earthstone, the 2014 Plan was amended to increase the number of shares of Class A Common Stock authorized to be issued under the 2014 Plan by 4.3 million shares, to a total of 5.8 million shares. Each RSU represents the contingent right to receive one share of Class A Common Stock. The holders of outstanding RSUs do not receive dividends or have voting rights prior to vesting and settlement. Prior to May 9, 2017, the Company determined the fair value of granted RSUs based on the market price of the Common Stock on the date of the grant. Beginning on May 9, 2017, the Company began determining the fair value of granted RSUs based on the market price of the Class A Common Stock on the date of the grant. Compensation expense for granted RSUs is recognized on a straight-line basis over the vesting and is net of forfeitures, as incurred.

The table below summarizes unvested RSU activity for the year ended December 31, 2017:

	Shares	Weighted-Average Grant Date Fair Value
Unvested RSUs at December 31, 2016	781,500	$ 12.53
Granted	949,000	$ 9.80
Forfeited	(58,041)	$ 12.98
Vested	(703,214)	$ 12.44
Unvested RSUs at December 31, 2017	969,245	$ 9.89

During the year ended December 2017, Earthstone granted 910,000 RSUs to employees and 39,000 RSUs to certain members of the Board with vesting periods varying from 12 months to 36 months. The total grant date fair value of the RSUs granted during the years 2017 and 2016 were $9.8 million and $9.3 million, respectively, with a weighted average grant fair value per share of $9.80 and $12.53, respectively. There were no RSUs granted during 2015. The total vesting date fair value of the RSUs that vested during 2017 was $8.3 million. There were no RSUs that vested during the years 2016 and 2015. As of December 31, 2017, there was approximately $8.4 million of total unrecognized stock-based compensation expense related to unvested RSUs, which will be amortized over the remaining vesting periods. The weighted average remaining vesting period of the unrecognized compensation expense is 0.91 years.

Stock-based compensation expense for the years ended December 31, 2017 and 2016 was $6.6 million and $3.3 million, respectively. There was no stock-based compensation expense for the year ended December 31, 2015. Stock-based compensation expense is recorded in the Consolidated Statements of Operations with a corresponding increase in Additional paid-in capital within the Consolidated Balance Sheet.

Note 12. Long-Term Debt

Credit Agreement

On May 9, 2017, in connection with the closing of the Bold Transaction, the Company exited its credit agreement dated December 19, 2014, by and among Earthstone, OVR 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 (as amended, modified or restated from time to time, the "ESTE Credit Agreement"). At that time, all outstanding borrowings of $10.0 million under the ESTE Credit Agreement were repaid and $0.5 million of remaining unamortized deferred financing costs were expensed and included in Write-off of deferred financing costs in the Consolidated Statements of Operations.

On May 9, 2017, EEH (the "Borrower"), Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden Op, Bold, Bold Operating, LLC (the "Guarantors"), BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, Wells Fargo Bank, National Association as Syndication Agent and the lenders party thereto (the "Lenders"), entered into a credit agreement (the "EEH Credit Agreement").

The borrowing base under the EEH Credit Agreement is currently $185.0 million, and is subject to redetermination on or about November 1st and May 1st of each year. The amounts borrowed under the EEH Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus 2.25% to 3.25% or (b) the prime lending rate of Bank of Texas plus 1.25% to 2.25%, depending on the amounts borrowed under the EEH Credit Agreement. Principal amounts outstanding under the EEH Credit Agreement are due and payable in full at maturity on May 9, 2022. All of the obligations under the EEH Credit Agreement, and the guarantees of those obligations, are secured by substantially all of EEH's assets. Additional payments due under the EEH Credit Agreement include paying a commitment fee of 0.50% per year to the Lenders in respect of the unutilized commitments thereunder, as well as certain other customary fees.

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

In addition, the EEH Credit Agreement requires EEH to maintain the following financial covenants: a current ratio of not less than 1.0 to 1.0 and a leverage ratio of not greater than 4.0 to 1.0. Leverage ratio means the ratio of (i) the aggregate debt of EEH and its consolidated subsidiaries as at the last day of the fiscal quarter (excluding any debt from obligations relating to non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives) to (ii) the product of EBITDAX for such fiscal quarter multiplied by four. The term "EBITDAX" means, for any period, the sum of consolidated net income for such period plus (a) the following expenses or charges to the extent deducted from consolidated net income in such period: (i) interest, (ii) taxes, (iii) depreciation, (iv) depletion, (v) amortization, (vi) non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives, (vii) exploration expenses, (viii) impairment expenses, and (ix) non-cash compensation expenses and minus (b) to the extent included in consolidated net income in such period, non-cash gains under FASB ASC 815 as a result of changes in the fair market value of derivatives.

The EEH Credit Agreement contains customary affirmative covenants and defines events of default to include failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default, and if Frank A. Lodzinski ceases to serve and function as Chief Executive Officer of EEH and the majority of the Lenders do not approve of Mr. Lodzinski's successor. Upon the occurrence and continuance of an event of default, the Lenders have the right to accelerate repayment of the loans and exercise their remedies with respect to the collateral. As of December 31, 2017, EEH was in compliance with all covenants under the EEH Credit Agreement.

As of December 31, 2017, the Company had a $185.0 million borrowing base under the EEH Credit Agreement, of which $25.0 million was outstanding, bearing an annual interest rate of 3.7611%, resulting in an additional $160.0 million of borrowing base availability under the EEH Credit Agreement.

Promissory Note

In July 2016, Earthstone issued a $5.1 million unsecured promissory note (the "Note") to a drilling rig contractor in settlement of rig idle charges and the termination amount of the contract. These expenses which were incurred from late January 2016 through December 31, 2016 and were recorded in Rig idle and termination expense in the Consolidated Statements of Operations for the year ended December 31, 2016. The Note was assigned to EEH in connection with the closing of the Bold Transaction. In December 2017, the remaining balance of the Note was paid in full.

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

	December 31,	
	2017	2016
Credit Agreement	$ 25,000	$ 10,000
Promissory note	—	4,297
Total debt	25,000	14,297
Less: Current portion of long-term debt	—	(1,604)
Long-term debt	$ 25,000	$ 12,693

For the year ended December 31, 2017, the Company had borrowings of $85.0 million and $74.3 million in repayments of borrowings. The borrowings included $58.0 million related to the repayments of all outstanding borrowings under Bold's credit agreement which were assumed by EEH in connection with the closing of the Bold Transaction. The repayments primarily included $35.0 million of the proceeds received from the Class A Common Stock offering in October 2017 and $25.0 million of the proceeds received from the Bakken Sale in December 2017. As stated above, in December 2017, the remaining balance of the Note was paid in full.

For the years ended December 31, 2017, 2016 and 2015, interest on all outstanding debt averaged 4.26%, 4.03% and 1.68% per annum, respectively, of which excluded commitment fees of $0.3 million for each period ended and amortization of deferred financing costs of $0.3 million for each period ended, respectively.

The Company capitalized $1.4 million, $0.1 million and $0.1 million, respectively, of costs associated with the credit agreements for the years ended December 31, 2017, 2016 and 2015. These capitalized costs are included in Other noncurrent assets in the Consolidated Balance Sheets. The Company's policy is to capitalize the financing costs associated with its debt and amortize those costs on a straight-line basis over the term of the associated debt.

Note 13. Asset Retirement Obligations

The Company has asset retirement obligations associated with the future plugging and abandonment of oil and natural 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, 2017 and 2016 *(in thousands)*:

	2017	2016
Beginning asset retirement obligations	$ 6,013	$ 5,075
Liabilities acquired (1)	359	250
Liabilities incurred	77	165
Property dispositions (1)	(4,401)	—
Liabilities settled	(9)	(15)
Accretion expense	434	551
Revision of estimates	(119)	(13)
Ending asset retirement obligations	$ 2,354	$ 6,013

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

Note 14. 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 Energy, LLC ("Flatonia"), which owns approximately 10.7% of the outstanding Class A Common Stock as of December 31, 2017, is a party to a joint operating agreement (the "Operating Agreement") with the Company. The Operating Agreement covers certain jointly owned oil and natural gas properties located in the Eagle Ford Trend of south Texas. In connection with the Operating Agreement, the Company made payments to Flatonia of $26.5 million, $26.6 million and $33.9 million, and received payments from Flatonia of $5.4 million, $21.7 million and $66.7 million, respectively, for the years ended December 31, 2017, 2016 and 2015. At December 31, 2017 and 2016, amounts receivable due from Flatonia in connection with the Operating Agreement were $1.3 million and $1.5 million, respectively. Amounts payable due to Flatonia in connection with the Operating Agreement were $3.1 million at December 31, 2016. There were no payables outstanding and due to Flatonia as of December 31, 2017.

Our majority shareholder consists of various investment funds managed by a venture capital firm who may manage other investments in entities with which we interact in the normal course of business.

Note 15. Commitments and Contingencies

Contractual Commitments

Future minimum contractual commitments as of December 31, 2017 under non-cancelable agreements having remaining terms in excess of one year are as follows:

	2018	2019	2020	2021	2022	Thereafter
Gas contract	$ 1,643	$ 1,643	$ 1,647	$ 680	$ —	$ —
Office leases	854	723	—	—	—	—
Total	$ 2,497	$ 2,366	$ 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, Midland, Texas and Denver, Colorado. Rent expense was approximately $0.9 million, $0.8 million, and $0.8 million for the years ended December 31, 2017, 2016, and 2015, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2017 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, Earthstone 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 Earthstone, 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 claimed the operator 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. In December 2017, we resolved the dispute with no material impact on the Company.

Olenik v. Lodzinksi et al.: On June 2, 2017, Nicholas Olenik filed a purported shareholder class and derivative action in the Delaware Court of Chancery against Earthstone's Chief Executive Officer, along with other members of the Board, EnCap, Bold, Bold Holdings and OVR. The complaint alleges that Earthstone's directors breached their fiduciary duties in connection with the Bold Contribution Agreement. The Plaintiff asserts that the directors negotiated the Bold Transaction to benefit EnCap and its affiliates, failed to obtain adequate consideration for the Earthstone shareholders who were not affiliated with EnCap or Earthstone management, did not follow an adequate process in negotiating and approving the Bold Transaction and made materially misleading or incomplete proxy disclosures in connection with the Bold Transaction. The suit seeks unspecified damages and purports to assert claims derivatively on behalf of Earthstone and as a class action on behalf of all persons who held Common Stock up to March 13, 2017, excluding defendants and their affiliates. Earthstone and each of the other defendants believe the claims are entirely without merit and they intend to mount a vigorous defense. The outcome of this suit is uncertain, and while Earthstone is confident in its position, any potential monetary recovery or loss to Earthstone cannot be estimated at this time.

On August 18, 2017, litigation captioned *Trinity Royal Partners, LP v. Bold Energy III LLC, et al.* was filed with the 142nd Judicial District of the District Court in Midland County, Texas, asserting breach of contract and indemnity claims for alleged damages from loss of property relating to two oil and natural gas wells in which Bold was the operator. Trinity Royalty Partners, LP ("Trinity") alleges that Bold is required to indemnify Trinity under the terms of an Assignment and a Participation and Joint Development Agreement between Bold and Trinity. Damages are alleged to include costs incurred in attempting to repair and restore an oil and natural gas well and for the loss of future reserves attributable to both wells. Trinity is seeking approximately $7.2 million in damages and attorneys' fees. Earthstone and Bold believe the suit is without any merit and Bold intends to mount a vigorous defense. The outcome of this suit is uncertain, and while the Company is confident in its position, any potential monetary recovery or loss to the Company cannot be estimated at this time.

Note 16. Income Taxes

The following table shows the components of the Company's income tax provision for the years ended December 31, 2017, 2016 and 2015 (*in thousands*):

	Years Ended December 31,		
	2017	2016	2015
Current:			
Federal	$ —	$ —	$ —
State	(15)	—	(91)
Total current	(15)	—	(91)
Deferred:			
Federal	16,186	(515)	26,214
State	202	(13)	319
Total deferred	16,388	(528)	26,533
Total income tax benefit (provision)	$ 16,373	$ (528)	$ 26,442

Effective Tax Rate

Following the closing of the Bold Transaction, the Company continues to record an income tax provision consistent with its status as a corporation. The Company's 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 US, Earthstone, and Lynden Corp. 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 be offset by tax attributes of Earthstone. Following the Bold Transaction, Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the noncontrolling interest, as well as any standalone income or loss generated by each company. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

A reconciliation of the effective tax rate to the statutory rate for the years ended December 31, 2017 and 2016 is as follows (*in thousands, except percentages*):

	Years Ended December 31,					
	2017			2016		
	U.S.	Canada	Total	U.S.	Canada	Total
Net loss before income taxes	$ (61,082)	$ (24)	$ (61,106)	$ (54,032)	$ 19	$ (54,013)
Statutory rate	34%	26%		34%	26%	
Tax benefit computed at statutory rate	(20,768)	(8)	(20,776)	(18,370)	5	(18,365)
Noncontrolling interest	12,118	—	12,118	—	—	—
Non-deductible impairment of goodwill	—	—	—	5,961	—	5,961
Non-deductible transaction costs	—	—	—	878	—	878
Non-deductible general and administrative expenses	168	—	168	5	—	5
Return to accrual	(486)	—	(486)	15	—	15
State income taxes, net of Federal benefit	(191)	—	(191)	(128)	—	(128)
Valuation allowance	(15,483)	6	(15,477)	12,167	(5)	12,162
Federal rate change	7,824	—	7,824	—	—	—
State rate change	445	—	445	—	—	—
Rate differential on Canadian activity	—	2	2	—	—	—
Total income tax (benefit) expense	$ (16,373)	$ —	$ (16,373)	$ 528	$ —	$ 528
Effective tax rate	26.8%	0.0%	26.8%	-1.0%	0.0%	-1.0%

During the year ended December 31, 2017, the Company recorded a total income tax benefit of $16.4 million which was primarily driven by the change in valuation allowance associated with the Bold Transaction. For Lynden US, the Company recorded an income tax benefit of $8.6 million, of which $4.8 million related to the reduction of that amount in its deferred tax liability resulting from the federal corporate income tax rate reduction to 21% as described below. Additionally, the Company recorded an income tax benefit for Earthstone of $7.7 million which resulted from a change in assessment of the realization of its net deferred tax assets due to the deferred tax liability that was recorded with respect to its investment in EEH as part of the Bold Transaction as an adjustment to Additional paid-in capital within the Consolidated Balance Sheet. Additionally, Earthstone recorded income tax expense of $12.6 million related to the reduction of that amount in its deferred tax asset resulting from the federal corporate income tax rate reduction to 21% as described below, which was fully offset by the reduction in its valuation allowance for that amount because the future realization of such loss cannot be reasonably assured and is subject to a full valuation allowance.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the TCJA, resulting in significant modifications to existing law. Our consolidated financial statements for the year ended December 31, 2017, reflect certain effects of the TCJA, which includes the federal corporate income tax rate reduction to 21%. Consistent with Staff Accounting Bulletin No. 118 issued by the SEC, which provides for a measurement period of one year from the enactment date to finalize the accounting for effects of the TCJA, the Company provisionally recorded income tax expense of $7.8 million related to the TCJA. In accordance with SEC guidance, provisional amounts may be refined as a result of additional guidance from, and interpretations by, U.S. regulatory and standard-setting bodies, and changes in assumptions. In the subsequent period, provisional amounts will be adjusted for the effects, if any, of interpretative guidance issued after December 31, 2017, by the U.S. Department of the Treasury. The effects of the TCJA may be subject to changes for items that were previously reported as provisional amounts, as well as any element of the TCJA for which a provisional estimate could not be made, and such changes could be material.

The Company has made provisional computations of the impact of the TCJA as provided for under SAB 118, including transition tax on the mandatory deemed repatriation of foreign earnings and executive compensation limitations under Internal Revenue Code Section 162(m), among others. The Internal Revenue Service is expected to issue additional guidance clarifying provisions of the Act. As additional guidance is issued one or more of the provisional amounts may change.

The Company's effective tax rate for the year ended December 31, 2016, was approximately (1.0)% which was less than the U.S. Federal statutory tax rate primarily due to both the recording of a $12.2 million valuation allowance as the realizability of the Company's deferred tax assets is not more likely-than-not, and $6.0 million reduction of income tax benefit resulting from non-deductible impairment of goodwill.

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

	Year Ended December 31, 2015
Net loss before income taxes	$ (143,097)
Tax benefit computed at Federal statutory rate	(48,653)
Non-deductible general and administrative expenses	534
Return to accrual	(1,398)
State income taxes, net of Federal benefit	(743)
Valuation allowance	23,818
Total income tax (benefit) expense	$ (26,442)
Effective tax rate	18.5%

The Company's 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 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 natural 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, 2017 and 2016 are as follows (*in thousands*):

	December 31, 2017	December 31, 2016
Deferred noncurrent income tax assets (liabilities):		
Office and other equipment	$ —	$ (48)
Oil & gas properties	2,998	7,428
Asset retirement obligation	—	2,042
Basis difference in subsidiary obligation	(2,268)	(4,226)
Intangible assets	—	36
Unrealized derivative loss	—	2,145
Stock-based compensation	—	1,148
Investment in Partnerships	(111)	—
Federal net operating loss carryforward	12,986	15,109
Other	—	186
Net deferred noncurrent tax assets	13,605	23,820
Valuation allowance	(24,120)	(39,596)
Net deferred tax liability	$ (10,515)	$ (15,776)

As of December 31, 2017, the Company had a valuation allowance recorded against its deferred tax assets of $24.1 million which is in excess of its net deferred noncurrent tax assets of $13.6 million, as presented above. The Company's corporate organizational structure requires the filing of two separate consolidated U.S. Federal corporate income tax returns, one separate U.S. Federal partnership income tax return 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, 2017, the deferred tax assets and liabilities related to the two U.S. Federal corporate income tax returns and one Canadian income tax return are a $20.5 million deferred tax asset, an $8.5 million deferred tax liability and a $3.6 million deferred tax asset, respectively, before considering the valuation allowance of $24.1 million.

As of December 31, 2016, the Company had 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, 2017, the Company had estimated U.S. net operating loss carryforwards of $49.1 million, the first expiring in 2034 and the last in 2037, 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 ("Sec 382") of the Internal Revenue Code of 1986, as amended (the "Code"). 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, 2017, the Company had 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, 2017, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities.

Note 17. Profit Sharing Plan

The Company sponsors a 401(k) defined contribution plan (the "401(k) Plan") for substantially all of its employees, which was initiated in April 2017. Eligible employees may make contributions to the 401(k) Plan by electing to contribute up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to six percent of the eligible employee's annual compensation contributed. The Company's matching contributions vest immediately. The Company's contributions to the 401(k) Plan for the year ended December 31, 2017 were $0.3 million.

Note 18. Supplemental Selected Quarterly Financial Data (Unaudited)

(In thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Oil and gas revenues	$ 15,343	$ 25,777	$ 31,282	$ 35,676
(Loss) income from operations	(3,433)	(67,093)	8,546	12,105
Net income (loss) attributable to Earthstone Energy, Inc.	729	(17,123)	1,556	2,324
Net income (loss) per common share attributable to Earthstone Energy, Inc.:				
Basic and diluted	$ 0.03	$ (0.75)	$ 0.07	$ 0.09
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 attributable to Earthstone Energy, Inc.	(6,421)	(11,172)	(3,900)	(33,048)
Net loss per common share attributable to Earthstone Energy, Inc.:				
Basic and diluted	$ (0.46)	$ (0.69)	$ (0.17)	$ (1.48)

Second quarter 2017 loss from operations includes a non-cash impairment charge of $66.6 million related to the Company's oil and natural gas properties, as discussed in *Note 6. Oil and Natural Gas Properties.*

Fourth quarter 2016 loss from operations includes a non-cash impairment charge of $6.8 million related to the Company's 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 related to its goodwill, as discussed in *Note 7. Goodwill*. Second quarter 2016 loss from operations includes $5.1 million of expenses related to the termination of a drilling rig, as discussed in *Note 12. Long-Term Debt*.

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 natural 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 natural gas activities for 2017, 2016 and 2015 were entirely within the United States of America. Costs incurred in oil and natural gas producing activities were as follows (*in thousands*):

	Years Ended December 31,		
	2017 (1)	2016	2015
Acquisition cost:			
Proved	$ 315,376	$ 48,116	$ 4,508
Unproved	245,589	26,600	10,646
Exploration costs:			
Exploratory drilling	—	—	—
Geological and geophysical	1	5	142
Development costs	77,876	28,577	56,862
Total additions	$ 638,842	$ 103,298	$ 72,158

(1) Acquisition costs incurred during 2017 consisted primarily of the assets acquired in the Bold Transaction described in *Note 3. Acquisitions and Divestitures* of the Notes to Consolidated Financial Statements.

During the year ended December 31, 2017, additions to oil and natural gas properties of $0.1 million were recorded for estimated costs of future abandonment related to new wells drilled or acquired. During the years ended December 31, 2016 and 2015, additions to oil and natural 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, 2017, 2016 and 2015, the Company had no capitalized exploratory well costs, nor costs related to share-based compensation, general corporate overhead or similar activities.

Capitalized Costs

Capitalized costs, impairment, and depreciation, depletion and amortization relating to the Company's oil and natural gas properties producing activities, all of which are conducted within the continental United States as of December 31, 2017 and 2016, are summarized below (*in thousands*):

	December 31,	
	2017	2016
Oil and gas properties, successful efforts method:		
Proved properties	$ 714,180	$ 476,832
Accumulated impairment to proved properties	(103,608)	(113,760)
Proved properties, net of accumulated impairments	610,572	363,072
Unproved properties	319,569	100,612
Accumulated impairment to Unproved properties	(44,543)	(48,889)
Unproved properties, net of accumulated impairments	275,026	51,723
Total oil and gas properties, net of accumulated impairments	885,598	414,795
Accumulated depreciation, depletion and amortization	(118,028)	(145,393)
Net oil and gas properties	$ 767,570	$ 269,402

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, 2017, 2016 and 2015 have been prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

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, 2017, 2016, and 2015 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate ("WTI") spot prices which equates to $51.34 per barrel, $42.75 per barrel, and $50.28 per barrel, respectively. The natural gas prices as of December 31, 2017, 2016 and 2015 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $2.98 per MMBtu, $2.48 per MMBtu and $2.59 per MMBtu, respectively. Natural gas liquids are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics. The natural gas liquids prices used to value reserves as of December 31, 2017, 2016 and 2015 averaged $22.59 per barrel, $13.21 per barrel and $14.11 per barrel, 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 proved oil, natural gas and NGLs reserves for the years ended December 31, 2017, 2016 and 2015 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
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
Extensions and discoveries	19,558	29,644	6,264	30,763
Sales of minerals in place	(1,833)	(6,853)	(1)	(2,976)
Purchases of minerals in place	28,176	46,709	9,950	45,911
Production	(1,828)	(3,260)	(500)	(2,872)
Revision to previous estimates	(3,857)	4,447	215	(2,901)
Balance - December 31, 2017 (1)	47,327	91,088	17,468	79,976
Proved developed reserves:				
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
December 31, 2017 (2)	11,949	23,336	4,123	19,961
Proved undeveloped reserves:				
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
December 31, 2017 (3)	35,378	67,752	13,345	60,015

(1) Includes 26.8 MMBbl of oil, 51.6 Bcf of natural gas and 9.9 MMBbl of NGL reserves attributable to noncontrolling interests.
(2) Includes 6.8 MMBbl of oil, 13.2 Bcf of natural gas and 2.3 MMBbl of NGL reserves attributable to noncontrolling interests.
(3) Includes 20.0 MMBbl of oil, 38.4 Bcf of natural gas and 7.6 MMBbl of NGL reserves attributable to noncontrolling interests.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* In 2017, total extensions and discoveries of 30,763 MBOE was a result of successful drilling results and well performance primarily related to the Midland Basin. The closing of the Bold Transaction in May 2017 which included primarily operated acreage in the Midland Basin was a significant contributor to this.
- *Sales of minerals in place.* Sales of minerals in place totaled 2,976 MBOE during 2017 and were primarily related to the disposition of the Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2017, total purchases of minerals in place of 45,911 MBOE were primarily attributable to the Bold Transaction, whereby the Company acquired interests in 63 producing oil and natural gas wells, four proved

developed non-producing wells and undeveloped acreage in the Midland Basin, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

- *Revision to previous estimates.* In 2017, the downward revisions of prior reserves of 2,901 MBOE consisted of negative revisions to PUD reserves of 4,832 MBOE with improved proved developed reserves of 1,931 MBOE. PUD revisions are a result of (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. Positive revisions are primarily a result of increased oil and natural gas prices during 2017.

Notable changes in proved reserves for the year ended December 31, 2016 included the following:

- *Extension and discoveries.* In 2016, total extensions and discoveries of 423 MBOE were primarily attributable to the successful drilling on the operated Eagle Ford and non-operated Bakken properties.
- *Purchase of minerals in place.* In 2016, total purchases of minerals in place of 10,647 MBOE were primarily attributable to the Lynden Arrangement, whereby the Company acquired interests in non-operated Midland Basin properties.
- *Revision to previous estimates.* In 2016, the downward revision to previous estimates of 10,128 MBOE for total proved reserves occurred primarily as a result of decreased oil and natural gas prices.

Notable changes in proved reserves for the year ended December 31, 2015 included the following:

- *Extensions and discoveries.* In 2015, total extensions and discoveries of 685 MBOE were primarily attributable to the successful drilling on the operated Eagle Ford and non-operated Bakken properties.
- *Sales of minerals in place.* Sales of minerals in place totaled 1,344 MBOE during 2015 and were primarily related to the disposition of the Company's Louisiana properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2015, total purchases of minerals in place of 1,962 MBOE were primarily attributable to interests acquired in the Eagle Ford Trend.
- *Revision to previous estimates.* In 2015, the downward revision to previous estimates of 9,484 MBOE for total proved reserves occurred primarily as a result of decreased oil and natural gas prices.

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. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and analogous producing wells for each area or field. PUD locations were limited to areas of uniformly high-quality reservoir properties, between existing commercial producers where the reservoir can, with reasonable certainty, be judged to be continuous with existing producers and contain economically producible oil and natural gas on the basis of available geoscience and engineering data.

Changes in PUD reserves for the years ended December 31, 2017, 2016 and 2015 were as follows (*in MBOE*):

Proved undeveloped reserves at December 31, 2014	12,392
Conversions to developed	(1,700)
Extensions and discoveries	685
Purchases of minerals in place	1,924
Revision to previous estimates	(9,340)
Proved undeveloped reserves at December 31, 2015	3,961
Conversions to developed	(169)
Extensions and discoveries	293
Purchases of minerals in place	873
Revision to previous estimates	(2,268)
Proved undeveloped reserves at December 31, 2016	2,690
Conversions to developed	(2,756)
Extensions and discoveries	27,977
Sales of minerals in place	(391)
Purchases of minerals in place	37,327
Revision to previous estimates	(4,832)
Proved undeveloped reserves at December 31, 2017 (1)	60,015

(1) Includes 34,029 MBOE attributable to noncontrolling interests.

2017 Changes in PUD reserves

Conversions to developed. In the Company's year-end 2016 plan to develop its PUDs within five years, the Company estimated that $6.9 million of capital would be expended in 2017 and that it would convert 732 MBOE. Because of the improvement in commodity prices and the change in its development plan for 2017, the Company actually spent $8.5 million to convert 622 MBOE to developed. The Company's plan changed in that it developed more oil PUDs and elected not to participate in natural gas PUDs which included the above mentioned 443 MBOE associated with the Eagle Ford non-participation. The capital to develop the Company's oil PUDs was higher on a per unit basis than the natural gas PUDs however the margins are higher for oil PUDs. The oil PUDs further benefited the Company's longer-term operated development plans. Since the Bold Transaction closed in May 2017, the associated capital plan for the properties acquired in the Bold Transaction during 2017 was not considered in the Company's year-end 2016 report. The Company did however incur $63.4 million to convert 2,134 MBOE of purchased PUD reserves to Developed. The Company intends to convert its proved undeveloped reserves into proved developed producing reserves in accordance with its estimates as of the date of the Company's year-end 2017 reserve report.

Extensions and discoveries. Additionally, 27,977 MBOE were added as extensions and discoveries due to successful drilling results on the Company's acreage positions because of the wells it drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to the Company's acreage. All of these drilling results increased the confidence of the reservoir continuity and performance of the associated reservoirs which increased the number of PUDs primarily in the Midland Basin.

Sales of minerals in place. Sales of minerals in place totaled 391 MBOE during 2017 and were primarily related to the disposition of the Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements

Purchases of minerals in place. During 2017, 37,327 MBOE were added to PUD reserves upon the closing of the Bold Transaction.

Revision to previous estimates. Revisions of 4,832 MBOE were primarily due to (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon the closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. This non-participation has no impact on the Company's ability to participate in future wells in this acreage position.

2016 Changes in PUD reserves

In early 2016, due primarily to depressed prices of oil and natural gas, the Company placed a lower emphasis on the conversion of its PUDs into proved developed producing reserves. In the Company's plan to convert these reserves over a five-year period, the Company estimated that $3.1 million of capital expenditure would be incurred in 2016, and the bulk of capital expenditures would occur over the following four years. The Company's actual 2016 capital expenditures for conversion of proved undeveloped reserves were $3.2 million, in line with its estimates. The Company also had estimated that these capital expenditures would result in 258 MBOE of proved developed producing reserves. The Company's actual estimated conversions were 169 MBOE. The difference was due primarily to one less location being drilled than the Company had estimated and lower initial reserve estimates for wells in certain units where all wells in the units had not been developed. This resulted in lower reserve estimates until the remaining wells in the units are drilled.

As of December 31, 2016, the Company's estimated proved undeveloped reserves were significantly lower than as of December 31, 2015, due to lower oil and natural gas prices used in making its 2016 estimates.

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

2015 Changes in PUD reserves

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

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 Topic 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 petroleum engineering firm. 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, 2017, 2016 and 2015, 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. Future production costs include per-well overhead expenses allowed under joint operating agreements, abandonment costs (net of salvage value), and a non-cancelable fixed cost agreement to reserve pipeline capacity of 10,000 MMBtu per day for gathering and processing. 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 a 10% discount factor.

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

	December 31,		
	2017	2016	2015
Future cash inflows	$ 2,948,989	$ 346,948	$ 481,131
Future production costs	(757,716)	(172,062)	(192,349)
Future development costs	(677,093)	(29,814)	(91,725)
Future income tax expense	(33,644)	—	—
Future net cash flows	1,480,536	145,072	197,057
10% annual discount for estimated timing of cash flows	(887,836)	(59,189)	(92,661)
Standardized measure of discounted future net cash flows (1)	$ 592,700	$ 85,883	$ 104,396

(1) At December 31, 2017, the standardized measure of discounted future net cash flows includes $336.1 million attributable to noncontrolling interests.

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, 2017 (*in thousands*):

	December 31,		
	2017	2016	2015
Beginning of year	$ 85,883	$ 104,396	$ 255,856
Sales of oil and gas produced, net of production costs	(81,926)	(24,998)	(29,152)
Sales of minerals in place	(15,553)	—	(2,470)
Net changes in prices and production costs	155,629	(102,143)	(288,064)
Extensions, discoveries, and improved recoveries	201,801	241	6,514
Changes in income taxes, net	(5,941)	—	88,944
Previously estimated development costs incurred during the period	76,447	27,770	26,977
Net changes in future development costs	(168,940)	102,267	6,697
Purchases of minerals in place	244,785	16,921	7,695
Revisions of previous quantity estimates	68,705	(45,239)	(16,671)
Accretion of discount	28,985	11,506	25,586
Changes in timing of estimated cash flows and other	2,825	(4,838)	22,484
End of year (1)	$ 592,700	$ 85,883	$ 104,396

(1) At December 31, 2017, the standardized measure of discounted future net cash flows includes $336.1 million attributable to noncontrolling interests.

EXHIBIT 10.17(a)

FIRST AMENDMENT TO CREDIT AGREEMENT

This FIRST AMENDMENT TO CREDIT AGREEMENT (this "***Amendment***") entered into on October 11, 2017, is among **EARTHSTONE ENERGY HOLDINGS, LLC**, a Delaware limited liability company ("***Borrower***"), **EARTHSTONE OPERATING, LLC**, a Texas limited liability company ("***EO***"), **EF NON-OP, LLC**, a Texas limited liability company ("***EF***"), **SABINE RIVER ENERGY, LLC**, a Texas limited liability company ("***Sabine***"), **EARTHSTONE LEGACY PROPERTIES, LLC**, a Texas limited liability company ("***ELP***"), **LYNDEN USA OPERATING, LLC**, a Texas limited liability company ("***LUO***"), **BOLD ENERGY III LLC**, a Texas limited liability company ("***BE***") and **BOLD OPERATING, LLC**, a Texas limited liability company ("***BO***"), as guarantors (EO, EF, Sabine, ELP, LUO, BE and BO, each a "***Guarantor***" and collectively, the "***Guarantors***"); each Lender (defined below) who is a signatory hereto and **BOKF, NA dba BANK OF TEXAS**, a national banking association, as administrative agent ("***Agent***") for the Lenders. The party or parties are sometimes individually referred to herein as a "***Party***" or collectively referred to as "***Parties***."

R E C I T A L S

WHEREAS, Borrower, Agent and the lenders from time to time party thereto (each a "***Lender***" and collectively, the "***Lenders***") are parties to that certain Credit Agreement dated as of May 9, 2017 (as may be amended, modified or restated from time to time, the "***Credit Agreement***"), whereby the Lenders agreed to make available to Borrower a credit facility upon the terms and conditions set forth therein; and

WHEREAS, Borrower has requested that Agent and the Lenders amend certain provisions of the Credit Agreement as provided herein; and

WHEREAS, subject to the terms hereof, the Agent and the Lenders are willing to agree to the amendment of certain provisions of the Credit Agreement as set forth herein.

NOW, THEREFORE, for and in consideration of the mutual covenants and agreements contained herein, and other good and valuable consideration, the Parties to this Amendment hereby agree as follows:

SECTION 1. **Defined Terms**. Except as may otherwise be provided herein, all capitalized terms which are defined in the Credit Agreement shall have the same meaning herein as therein, all of such terms and their definitions being incorporated herein by reference.

SECTION 2. **Amendment to Credit Agreement**. Subject to the conditions precedent set forth in ***Section 3*** hereof:

(a) ***Section 1.02*** of the Credit Agreement is hereby amended by inserting the following as new definitions:

"***DCS Expiration***" means the later of (x) November 9, 2022 and (y) the date set forth in clause (i) of "Revolving Credit Termination Date" at the time such Disqualified Capital Securities are issued.

"***Disqualified Capital Securities***" means any capital stock of such Person that, by its terms (or by the terms of any security or instrument into which it is convertible or for which it is exchangeable or exercisable), or upon the happening of any event, (i) matures (excluding any maturity as the result of an optional redemption by Borrower) or is mandatorily redeemable for any consideration (other than capital stock which would not constitute Disqualified Capital Securities), pursuant to a sinking fund obligation or otherwise, (ii) is redeemable for any consideration (other than capital stock which would not constitute Disqualified Capital Securities) at the option of the holder thereof, in whole or in part, prior to the DCS Expiration, (iii) is convertible into or exchangeable or exercisable (unless at the sole option of Borrower) for Debt (unless such conversion, exchange or exercise is at the option of the holder thereof and only exercisable after the DCS Expiration), (iv) contains any mandatory repurchase or payment obligation for any consideration (other than capital stock which would not constitute Disqualified Capital Securities), except for payments permitted under ***Section 9.04*** or (v) contains any repurchase or payment obligation for any consideration (other than capital stock which would not constitute Disqualified Capital Securities) at the option of the holder thereof, in whole or in part, prior to the DCS Expiration, except for payments permitted under ***Section 9.04***.

"***Preferred Equity***" means any preferred Capital Securities that rank senior to Borrower's common Capital Securities with respect to payment of distributions and/or distribution of assets upon liquidation, dissolution or winding-up of Borrower, but specifically excluding any such Capital Securities that constitute Disqualified Capital Securities.

"***Subordinated Debt***" means any term Debt of Borrower for borrowed money, other than revolving Debt, and any Disqualified Capital Securities of Borrower (and any refinancing or replacement of such term Debt or Disqualified Capital Securities), in any event, issued after October 11, 2017 which meets all of the following requirements:

(a) the agreements and instruments governing such term Debt or Disqualified Capital Securities shall not contain (i) any affirmative or negative covenant (including financial covenants) that is materially more restrictive than those set forth in this Agreement; provided that the inclusion of any covenant that is customary with respect to such type of term Debt or Disqualified Capital Securities and that is not found in this Agreement shall not be deemed to be more restrictive for purposes of this clause (a)(i), (ii) any restriction on the ability of Borrower or any of its Subsidiaries to amend, modify, restate or otherwise supplement this Agreement or the other Loan Documents except, in the case of term Debt, as provided pursuant to an intercreditor agreement or other agreement, the terms of which are reasonably satisfactory to the Agent and the Required Lenders (an "***Intercreditor Agreement***"), (iii) any restrictions on the ability of any Subsidiary of Borrower to guarantee the Obligations (as such Obligations may be amended, supplemented, modified, or amended and restated), provided that, in the case of term Debt, a requirement that any such Subsidiary also guarantee such term Debt shall not be deemed to be a violation of this clause (iii), (iv) any restrictions on the ability of Borrower or any Subsidiary of Borrower to pledge assets as collateral security for the Obligations (as such Obligations may be amended, supplemented, modified, or amended and restated but not increased) other than, with respect to such term Debt that is secured, any such restrictions otherwise being satisfactory to the Agent and the Majority Lenders; provided that, in any event, (x) a requirement that such term Debt be secured in compliance with clause (b) below shall not be deemed to be a violation of this clause (iv) and (y) a requirement that such term Debt be secured by the same assets that serve as collateral security for the Obligations shall not be deemed to be a violation of this clause (iv), (v) any cap or restrictions on the ability of Borrower or any Subsidiary of Borrower to incur Debt under this Agreement or any other Loan Document, except as provided in an Intercreditor Agreement ; (vi) in the case of term Debt, a scheduled maturity date that is the later of (x) November 9, 2022 and (y) the date 180 days after the date set forth in clause (i) of "Revolving Credit Termination Date" at the time such Debt is incurred, (vii) in the case of Disqualified Capital Securities, (x) a maturity (excluding any maturity as the result of an optional redemption by Borrower) or a requirement that it be mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or be redeemable at the option of the holder thereof, in whole or in part, on or prior to the DCS Expiration Date, or (y) any mandatory repurchase or payment obligation or other repurchase or payment obligation (in each case except for payments permitted under ***Section 9.04***) on or prior to the DCS Expiration Date, (viii) in the case of Disqualified Capital Securities, any requirement that it be secured or (ix) any amortization or other scheduled principal payments or, except as permitted by the Intercreditor Agreement, any mandatory principal payments, other than at the scheduled maturity thereof (other than customary offers to purchase upon a change of control and customary acceleration rights after an event of default);

(b) if such term Debt is secured, the Liens securing such Debt covers the same assets which serve as collateral for the Obligations pursuant to the Loan Documents and are subordinated to the Liens securing the Obligations pursuant to an Intercreditor Agreement;

(c) on the date of incurrence of such term Debt or Disqualified Capital Securities, immediately before and after giving effect to such incurrence and any concurrent repayment of Debt with the proceeds thereof, Borrower is in compliance, on a pro forma basis, with ***Section 9.12*** of this Agreement; and

(d) no Default or Event of Default exists on the date of incurrence of such term Debt or Disqualified Capital Securities or will occur immediately after, and as a result of, the issuance of such term Debt or Disqualified Capital Securities.

(b) The definition of "***Change of Control***" in ***Section 1.02*** of the Credit Agreement is hereby amended and restated in its entirety as follows:

"***Change of Control***" means (a) Frank A. Lodzinski shall cease or fail for any reason to serve and function as the Chief Executive Officer of Borrower and he shall not be succeeded in such position by an individual reasonably acceptable to the Majority Lenders or (b) any "change in control" (as set forth in any document governing any Subordinated Debt) occurs that obligates Borrower or any other Loan Party to repurchase, redeem or repay all or any part of the Subordinated Debt provided for therein.

(c) Clause (xi) of the definition of "***Debt***" in ***Section 1.02*** of the Credit Agreement is hereby amended and restated in its entirety as follows:

"(xi) Disqualified Capital Securities (for purposes hereof, the amount of any Disqualified Capital Securities shall be its liquidation value and, without duplication, the amount of all obligations of such Person with respect to the redemption, repayment or other repurchase in respect of Disqualified Capital Securities);"

(d) ***Section 2.07(b)*** of the Credit Agreement is hereby amended by adding the following as a new clause (vii):

"(vii) <u>Subordinated Debt</u>. Upon each reduction of the Borrowing Base under ***Section 2.08(h)*** resulting from the issuance of Subordinated Debt, if a Borrowing Base Deficiency then exists or results therefrom, then the Borrower shall, concurrently with the receipt thereof, prepay the Loans with the net proceeds received from such issuance of Subordinated Debt in an amount necessary to eliminate such Borrowing Base Deficiency. If, because of LC Exposure, a Borrowing Base Deficiency remains after prepaying all of the Loans, Borrower shall pay to Agent on behalf of the Lenders an amount equal to such remaining Borrowing Base Deficiency to be held as cash collateral as provided in ***Section 2.10(b)***. Notwithstanding anything in this Agreement to the contrary, if at the time of any issuance of Subordinated Debt a Borrowing Base Deficiency exists, then Borrower shall, concurrently with the receipt thereof, prepay the Loans with the net proceeds received from such issuance of Subordinated Debt to the extent necessary to eliminate the portion of the Borrowing Base Deficiency resulting from such issuance of Subordinated Debt and such preexisting Borrowing Base Deficiency; and Borrower shall remain obligated, pursuant to the terms of this Agreement, to eliminate any Borrowing Base Deficiency remaining after prepaying the Loans with the net proceeds from such issuance of Subordinated Debt."

(e) ***Section 2.08*** of the Credit Agreement is hereby amended by (i) renumbering existing clause (h) as clause (i) and (ii) adding the following as a new clause (h):

"(h) Redetermination Concurrent with Subordinated Debt Issuance. Effective immediately upon the issuance of any Subordinated Debt by Borrower on or after May 1, 2018, the Borrowing Base shall automatically reduce on the effective date of such issuance by an amount equal to twenty-five percent (25%) of (A) the amount of such Subordinated Debt issued *minus* (B) to the extent such Subordinated Debt constitutes a refinancing of existing Subordinated Debt, the amount of existing Subordinated Debt being refinanced thereby."

(f) ***Section 8.01(d)*** of the Credit Agreement is hereby amended by adding the following to the end thereof:

"Promptly after Borrower knows that any "default" or any "event of default" has occurred under any document or agreement for Subordinated Debt, a notice of such occurrence, describing the same in reasonable detail and the action Borrower proposes to take with respect thereto."

(g) ***Section 8.01(j)*** of the Credit Agreement is hereby amended by adding the following after the words "similar agreement":

"(including any agreement relating to Subordinated Debt)"

(h) ***Article VIII*** of the Credit Agreement is hereby amended by adding the following as a new ***Section 8.15***:

"**Section 8.15 Designation of Senior Debt.** Borrower shall, and shall cause each Subsidiary of Borrower to, designate all Obligations as "designated senior indebtedness" under any Subordinated Debt documents or agreements."

(i) ***Section 9.01*** of the Credit Agreement is hereby amended by (i) renumbering existing clause (h) as clause (i) and (ii) adding the following as a new clause (h):

"(h) Subordinated Debt of Borrower and the guaranties given by Subsidiaries of Borrower with respect thereto; provided that, such Subordinated Debt does not exceed $100,000,000 in the aggregate."

(j) ***Section 9.02*** of the Credit Agreement is hereby amended by adding the following as a new clause (g):

"(g) Liens securing Subordinated Debt that is term Debt so long as (i) the creation, incurrence, assumption or existence of such Liens is permitted under an Intercreditor Agreement pertaining to such Subordinated Debt and (ii) such Subordinated Debt is permitted under ***Section 9.01(h)*** above."

(k) ***Section 9.04*** of the Credit Agreement is hereby amended by adding the following as new clauses (d) and (e):

"(d) cash distributions payable by Borrower to the holders of Borrower's Disqualified Capital Securities, provided (i) no such Restricted Payment shall exceed the cash amount required to be paid pursuant to the documents and agreements governing such Disqualified Capital Securities (for the avoidance of doubt, this clause (i) does not require Borrower to elect a payment in kind option for payment of distributions when such option is available), (ii) both before and after giving effect to the making of such Restricted Payment, no Default exists, (iii) both before and after giving effect to the making of such Restricted Payment, the pro forma Leverage Ratio shall be less than 3.00 to 1.00, and (iv) both before and after giving effect to the making of such Restricted Payment, the Borrowing Base Utilization is less than eighty-five percent (85%).

(e) cash distributions payable by Borrower to the holders of Borrower's Preferred Equity provided (i) no such Restricted Payment shall exceed the cash amount required to be paid pursuant to the documents and agreements governing such Preferred Equity (for the avoidance of doubt, this clause (i) does not require Borrower to elect a payment in kind option for payment of distributions when such option is available), (ii) both before and after giving effect to the making of such Restricted Payment, no Default exists, (iii) both before and after giving effect to the making of such Restricted Payment, the pro forma Leverage Ratio shall be less than 3.00 to 1.00, and (iv) both before and after giving effect to the making of such Restricted Payment, the Borrowing Base Utilization is less than eighty-five percent (85%)**.**"

(l) The parenthetical in ***Section 9.17*** of the Credit Agreement is hereby amended and restated in its entirety as follows:

"(other than (x) the Loan Documents and (y) documents and agreements relating to Subordinated Debt, to the extent permitted by the Intercreditor Agreement pertaining to such Subordinated Debt)"

(m) ***Article IX*** of the Credit Agreement is hereby amended by adding the following as new ***Sections 9.21*** and ***9.22***:

"**Section 9.21 Subordinated Debt.** Borrower shall not, nor shall it permit any of its Subsidiaries to, make any payments on account of principal (whether by redemption, purchase, retirement, defeasance, set-off or otherwise), interest, premiums and fees in respect of any Subordinated Debt prior to the scheduled maturity or due date thereof in any manner, or make any such payment in violation of any Intercreditor Agreement applicable thereto; provided that, the conversion, exchange, exercise or redemption of such Subordinated Debt for, or using the proceeds of, other Subordinated Debt that is permitted by this Agreement or Capital Securities (other than Capital Securities that constitute Disqualified Capital Securities) of Borrower that is (i) in accordance with the terms of such Subordinated Debt and (ii) permitted under the Intercreditor Agreement, if any, pertaining to such Subordinated Debt shall not be a violation of this ***Section 9.21***.

Section 9.22 **Additional Liens.** Borrower shall not, nor shall it permit any of its Subsidiaries to, grant a Lien on any Property to secure any Subordinated Debt without first (a) giving fifteen days' prior written notice to Agent thereof and (b) granting to Agent to secure the Obligations an Lien in the same Property pursuant to Security Instruments in form and substance satisfactory to Agent. In connection therewith, Borrower shall, or shall cause its Subsidiaries to, execute and deliver such other additional closing documents, certificates and legal opinions as may reasonably be requested by the Agent."

(n) ***Section 10.01*** of the Credit Agreement is hereby amended by (i) deleting the period at the end of clause (m) and replacing it with "; or" and (ii) adding the following as new clauses (n) and (o):

"(n) an "event of default" under any document or agreement relating to Subordinated Debt shall have occurred; or

(o) any of the provisions of any Intercreditor Agreement shall, for any reason, cease to be valid and binding or otherwise cease to be in full force and effect and valid, binding and enforceable in accordance with its terms against any Loan Party or any holder of Subordinated Debt, or shall be repudiated in writing by any such Person."

(o) **Amendments for section cross-reference updates**.

i. The Credit Agreement is amended by replacing the reference to "***Section 2.08(h)***" in the definition of "Redetermination Date" with "***Section 2.08(i)***".

ii. The Credit Agreement is amended by replacing the reference to "***Section 2.08(f)*** or ***Section 2.08(g)***" in ***Section 2.07(b)(ii)*** with "***Section 2.08(f)***, ***Section 2.08(g)*** or ***Section 2.08(h)***".

iii. The Credit Agreement is amended by replacing the reference to "***Sections 2.08(d)***, ***(e)*** and ***(f)***" in ***Section 2.08(a)*** with "***Sections 2.08(d)***, ***(e)***, ***(f)***, ***(g)*** and ***(h)***".

iv. The Credit Agreement is amended by replacing the reference to "***Sections 2.08(d)***, ***(e)***, ***(f)*** or ***(g)***" in ***Section 2.08(a)*** with "***Sections 2.08(d)***, ***(e)***, ***(f)***, ***(g)*** or ***(h)***".

SECTION 3. **Conditions of Effectiveness**. The obligations of Agent and the Lenders to amend the Credit Agreement as provided herein are subject to the fulfillment of the following conditions precedent:

(a) Agent shall have received counterparts of this Amendment, which shall have been executed by the Lenders, Borrower and the Guarantors.

(b) Borrower shall have made payment of all fees and expenses due and owing under the Credit Agreement including such fees and expenses specified in ***Section 6***.

(c) All representations and warranties set forth in each of the Loan Documents shall be true and correct.

(d) No Material Adverse Effect shall have occurred.

(e) No Default or Event of Default shall have occurred.

SECTION 4. Representations and Warranties. Borrower and each Guarantor represents and warrants to Agent and the Lenders, with full knowledge that Agent and the Lenders are relying on the following representations and warranties in executing this Amendment, as follows:

(a) It has the power and authority to execute, deliver and perform this Amendment, and all organizational action on the part of itself, as applicable, requisite for the due execution, delivery and performance of this Amendment has been duly and effectively taken.

(b) This Amendment and each other document executed and delivered in connection herewith constitute its legal, valid and binding obligation, to the extent it is a party thereto, enforceable against it in accordance with their respective terms, except as enforceability may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of creditors' rights generally or by equitable principles relating to enforceability.

(c) This Amendment does not and will not violate any provisions of (i) its Charter Documents; (ii) any contract, agreement, or instrument to which it is a party; or (iii) any requirement of any governmental authority to which it is subject. Its execution of this Amendment will not result in the creation or imposition of any lien upon its properties other than those permitted by the Credit Agreement and this Amendment.

(d) Its execution, delivery and performance of this Amendment does not require the consent or approval of any other Person, including, without limitation, any regulatory authority or governmental body of the United States of America or any state thereof or any political subdivision of the United States of America or any state thereof.

(e) As of the date of this Amendment, it is solvent and has taken no action such as may invoke applicable bankruptcy, insolvency, or similar laws affecting the enforcement of creditors' rights generally or by equitable principles relating to enforceability.

(f) No Default or Event of Default exists, and all of the representations and warranties made by it contained in the Credit Agreement are true and correct in all material respects on and as of this date other than those which have been disclosed to Lenders in writing (except to the extent such representations and warranties expressly refer to an earlier or other date, in which case they shall be true and correct as of such earlier or other date).

Except to the extent expressly set forth herein to the contrary, nothing in this ***Section 4*** is intended to amend any of the representations or warranties contained in the Agreement.

SECTION 5. Reference to and Effect on the Credit Agreement.

(a) Upon and after the execution of this Amendment by each of the parties hereto, each reference in the Credit Agreement to "*this Agreement*", "*hereunder*", "*hereof*" or words of like import referring to the Credit Agreement, and each reference in the other Loan Documents to "*the Credit Agreement*", "*thereunder*", "*thereof*" or words of like import referring to the Credit Agreement, shall mean and be a reference to the Credit Agreement as modified hereby. This Amendment shall constitute a Loan Document.

(b) Except as specifically amended by this Amendment, the Credit Agreement shall remain in full force and effect and is hereby ratified and confirmed.

SECTION 6. **Fees, Cost, and Expenses**. Borrower agrees to pay all reasonable legal fees and expenses to be incurred in connection with the preparation, reproduction, execution and delivery of this Amendment and the other instruments and documents to be delivered in connection with the transactions associated herewith, including reasonable attorneys' fees and out-of-pocket expenses of Agent, and agrees to save Agent harmless from and against any and all liabilities with respect to or resulting from any delay in paying or omission to pay such fees.

SECTION 7. **Extent of Amendment**. Except as otherwise expressly provided herein, neither the Credit Agreement nor the other Loan Documents are amended, modified or affected by this Amendment. Borrower and each Guarantor hereby ratifies and confirms that (i) except as expressly amended hereby, all of the terms, conditions, covenants, representations, warranties and all other provisions of the Credit Agreement, as applicable, remain in full force and effect, (ii) each of the other Loan Documents to which it is a party are and remain in full force and effect in accordance with their respective terms, and (iii) the Collateral granted by it is unimpaired by this Amendment.

Nothing contained in this Amendment nor any past indulgence by Agent and/or the Lenders, nor any other action or inaction on behalf of Agent and/or the Lenders (i) shall constitute or be deemed to constitute a waiver of any unknown or future Defaults or Events of Default which may now or in the future exist under the Credit Agreement or the other Loan Documents, or (ii) shall constitute or be deemed to constitute an election of remedies by Agent and/or the Lenders or a waiver of any of the rights or remedies of Agent and/or the Lenders provided in the Credit Agreement or the other Loan Documents or otherwise afforded at law or in equity.

SECTION 8. **Grant and Affirmation of Security Interest**. Borrower and each Guarantor hereby confirms and agrees that (i) any and all liens, security interests and other security or Collateral granted by it and now or hereafter held by Lenders as security for payment and performance of the Obligations are hereby renewed and carried forth to secure payment and performance of all of the Obligations, and (ii) the Loan Documents, as such may be amended in accordance herewith, are and remain legal, valid and binding obligations, enforceable in accordance with their respective terms, except as enforceability may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of creditors' rights generally or by equitable principles relating to enforceability.

SECTION 9. **Claims; Release**. As additional consideration to the execution, delivery, and performance of this Amendment by the parties hereto and to induce Agent and the Lenders to enter into this Amendment, Borrower and each Guarantor hereby represents and warrants that it does not know of any defenses, counterclaims or rights of setoff to the payment of any Obligations of Borrower or any Guarantor to Agent and/or the Lenders. In consideration of the amendments contained herein, Borrower and each Guarantor hereby waives and releases each of the Lenders and Agent from any and all claims and defenses, known or unknown, with respect to the Credit Agreement and the other Loan Documents and the transactions contemplated thereby.

SECTION 10. **Execution and Counterparts**. This Amendment may be executed in any number of counterparts and by different Parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of this Amendment by facsimile or other electronic transmission (such as Portable Document Format) and other Loan Documents shall be equally as effective as delivery of a manually executed counterpart of this Amendment and such other Loan Documents.

SECTION 11. **Governing Law**. This Amendment shall be governed by and construed in accordance with the laws of the State of Texas.

SECTION 12. **<u>Headings</u>**. Section headings in this Amendment are included herein for convenience and reference only and shall not constitute a part of this Amendment for any other purpose.

SECTION 13. **<u>NO ORAL AGREEMENTS</u>**. The rights and obligations of each of the parties to the loan documents shall be determined solely from written agreements, documents, and instruments, and any prior oral agreements between such parties are superseded by and merged into such writings. This Amendment and the other written loan documents executed by Borrower, Guarantor, Agent and/or the Lenders (*together with* any fee letters as they relate to the payment of fees after the closing date) represent the final agreement between such parties, and may not be contradicted by evidence of prior, contemporaneous, or subsequent oral agreements by such parties. There are no unwritten oral agreements between such parties.

[signature pages to follow]

IN WITNESS WHEREOF, the Parties hereto have caused this Amendment to be duly executed and delivered by their proper and duly authorized officers as of the Effective Date.

BORROWER:

EARTHSTONE ENERGY HOLDINGS, LLC
a Delaware limited liability company

By: /s/ Mark Lumpkin, Jr.
Name: Mark Lumpkin, Jr.
Title: Executive Vice President and Chief Financial Officer

GUARANTORS:

EARTHSTONE OPERATING, LLC,
a Texas limited liability company
EF NON-OP, LLC,
a Texas limited liability company
SABINE RIVER ENERGY, LLC,
a Texas limited liability company
EARTHSTONE LEGACY PROPERTIES, LLC,
a Texas limited liability company
LYNDEN USA OPERATING, LLC,
a Texas limited liability company
BOLD ENERGY III LLC,
a Texas limited liability company
BOLD OPERATING, LLC,
a Texas limited liability company

Each by: /s/ Mark Lumpkin, Jr.
Name: Mark Lumpkin, Jr.
Title: Executive Vice President and Chief Financial Officer

<u>LENDER AND AGENT:</u>

BOKF, NA dba BANK OF TEXAS,
as Agent and Lender

By: /s/ Martin W. Wilson
Martin W. Wilson
Senior Vice President

Signature Page to First Amendment to Credit Agreement (Earthstone Energy Holdings, LLC)

LENDER:

Wells Fargo Bank, N.A.
as Lender

By:	/s/ Edward Pak
Name:	Edward Pak
Title:	Director

Signature Page to First Amendment to Credit Agreement (Earthstone Energy Holdings, LLC)

LENDER:

Royal Bank of Canada,
as Lender

By: /s/ Emilee Scott
Name: Emilee Scott
Title: Authorized Signatory

Signature Page to First Amendment to Credit Agreement (Earthstone Energy Holdings, LLC)

LENDER:

SUNTRUST BANK,
as Lender

By: /s/ Yann Pirio
Name: Yann Pirio
Title: Managing Director

Signature Page to First Amendment to Credit Agreement (Earthstone Energy Holdings, LLC)

LENDER:

KeyBank National Association,
as Lender

By: /s/ George E. McKean
Name: George E. McKean
Title: Senior Vice President

LENDER:

IBERIABANK,
as Lender

By: /s/ Stacy Goldstein
Name: Stacy Goldstein
Title: Senior Vice President

Signature Page to First Amendment to Credit Agreement (Earthstone Energy Holdings, LLC)

Exhibit 10.20

PURCHASE AND SALE AGREEMENT

THIS PURCHASE AND SALE AGREEMENT (hereinafter referred to as this "Agreement"), dated November 16, 2017 (hereinafter referred to as the "Execution Date"), is made by and between **EARTHSTONE LEGACY PROPERTIES, LLC,** a Texas limited liability company (hereinafter referred to as "Seller"), and **STATOIL OIL & GAS LP** , a Delaware limited partnership (hereinafter referred to as "Buyer"). Seller and Buyer are herein collectively referred to as "Parties" and separately as "Party".

This Agreement shall be effective as of the Execution Date, but the conveyances of the Properties contemplated herein shall be effective as of 12:01 AM prevailing central time on December 1, 2017 (hereinafter referred to as the "Effective Time").

1.1 **Agreement.** At Closing, Seller shall sell, assign, transfer and convey and Buyer shall purchase and accept, in each case as of the Effective Time, for the consideration hereinafter set forth, and subject to the terms and provisions herein contained, all of Seller's right, title and interest, together with all of Seller's duties and obligations, in, to and under the following described properties, rights and interests (such right, title and interest, singularly referred to as the "Property" or collectively referred to as the "Properties"):

a. the oil, gas and/or mineral leases and other properties described in Exhibit A, including any ratifications, extensions and amendments thereto (hereinafter referred to as the "Leases"), and the lands covered thereby, including all fee mineral interests, royalty interests, overriding royalty interests, non-participating royalty interests, executive rights, production payments, net profits interests, reversionary interests, operating interests and any other leasehold or mineral interests of any kind or nature, and any lands pooled, unitized or communitized therewith (hereinafter referred to as the "Lands");

b. the oil, gas and condensate wells (whether producing, shut-in or temporarily abandoned), water source, water injection or other injection or disposal wells and systems located on, within the geographic boundaries of or otherwise affected by the Leases, the Lands or the Units (as defined herein), including those described in Exhibit B (hereinafter referred to as the "Wells");

c. all other rights (of whatever kind or character, whether legal or equitable, and whether vested or contingent) in the oil, gas and other minerals in and under or that may be produced from the Lands, Leases, Units and Wells, even though Seller's interest in the oil, gas and other minerals may be incorrectly described in, or omitted from, Exhibit A or Exhibit B;

d. all presently existing and valid oil, gas and/or mineral unitization, pooling, and/or communitization agreements, declarations and/or orders relating to Seller's interest in any of the Properties described in Articles 1.1(a), (b) and (c), and in the Properties covered and the units created thereby (including all units formed under orders, rules, regulations, or other official acts of any federal, state, or other authority having jurisdiction, voluntary unitization agreements, designations and/or declarations) (hereinafter referred to as the "Units");

e. all contracts or agreements, including all sales, purchase, exchange, gathering, transportation, processing and oil and gas marketing contracts, operating agreements, unit agreements, balancing agreements, farmout agreements, farmin agreements, participation agreements and exploration agreements, insofar and only to the extent that such agreements and contracts cover or relate to: (i) any of the Properties described in Articles 1.1(a), (b), (c), (f), or (g) or (ii) the exploration, development, operation, or maintenance thereof or the treatment, storage, transportation or marketing of production therefrom, including, those contracts or agreements described on Exhibit C (hereinafter collectively referred to as the "Contracts");

f. all materials, supplies, machinery, equipment, facilities, supervisory control and data acquisition systems, improvements and other personal property and fixtures located on the Lands or the Units (including but not by way of limitation, all Wells, wellheads, wellhead equipment, processing equipment, pumping units, flowlines, pipelines, gas lines, power lines, tubing, platforms, separators, treaters, rods, tanks, buildings, towers, SCADA equipment, radios, meters, computers, spare parts, junk, injection facilities, saltwater disposal facilities, compressors, compression facilities, gathering systems, and other equipment) that are used or held for use primarily in connection with any of the Properties described in Articles 1.1(a), (b), (c), (d) or (g) (hereinafter collectively referred to as the "Equipment");

g. all easements, rights-of-way, surface leases, fee surface interests, and other surface rights, all permits and licenses, and all other appurtenances being primarily used or held for use in connection with, or otherwise related to, the exploration, development, operation or maintenance of any of the Properties described in Articles 1.1(a), (b), (c) or (d), or the treatment, storage, transportation or marketing of production therefrom (or allocated thereto), including, without limitation, these set forth on Exhibit D;

h. the oil, gas, and other hydrocarbons (including crude oil, natural gas, casinghead gas, drip gasoline, natural gasoline, natural gas liquids, condensate, and other hydrocarbons, whether gaseous or liquid) (hereinafter collectively referred to as the "Hydrocarbons") produced from or attributable to the Wells, Lands or Units from and after the Effective Time; and

i. any and all original (or copies, if originals are not available) lease files, right-of-way files, division order files, well files, abstracts, title opinions, title files, contract/agreement files, marketing files, revenue files, accounting files, payment files and any and all other files, information, and records, including, without limitation, all seismic data to the extent that it is transferable, and geological records, data, surveys, and interpretations, insofar as they relate to any of the Properties described herein (hereinafter collectively referred to as the "Records").

1.2 **Excluded Assets**. All properties, rights and interests of Seller or its affiliates other than the Properties are retained by Seller or such affiliates, as applicable, and are referred to herein collectively as the "Excluded Assets".

2. **Purchase Price.** The purchase price for the Properties shall be the amount of Twenty-Seven Million Dollars and No/100 ($27,000,000.00), subject to the adjustments as provided herein (hereinafter referred to as the "Purchase Price") and the portion of the unadjusted Purchase Price allocated to each Well as reflected on Schedule 2.2, is herein referred to as the "Allocated Value"). Buyer has paid by wire transfer in immediately available funds, ten percent (10%) of the Purchase Price to Seller, to Seller's bank account, as a performance deposit (hereinafter referred to as the "Deposit") and the remainder of the Purchase Price shall be payable by Buyer to Seller at Closing by wire transfer in immediately available funds to Seller's bank account (the details of which shall be part of the Preliminary Settlement Statement (as defined herein)).

3. **Closing.** The closing (hereinafter referred to as the "Closing") of the sale of the Properties contemplated by this Agreement shall take place electronically on December 20, 2017 at 10:00 a.m., provided that all of the conditions to Closing set forth in Article 10 have been satisfied or waived (other than such conditions as may be, by their terms, only satisfied at the Closing or on the Closing Date). The date on which the Closing actually occurs may be referred to herein as the "Closing Date".

4. **Representations and Warranties.** Each Party (hereinafter referred to as the "Representing Party"), as to such Representing Party, represents and warrants to the other Party as of the Execution Date and the Closing Date (unless a specific date is set forth below, in which case such specific date shall apply to such representation and warranty), as follows:

a. Valid and Binding. Where Seller is the Representing Party, such Party is duly qualified and has full right and authority to own the Properties. Where Buyer is the Representing Party, as of the Closing, such Party shall be duly qualified and has full right and authority to own the Properties. This Agreement, the Assignment (as defined herein) (when delivered) and any other document executed by the Representing Party in connection herewith, will constitute the enforceable, valid, and binding obligations of the Representing Party, enforceable against the Representing Party in accordance with its terms.

b. Organization and Existence. The Representing Party is duly organized, validly existing and in good standing under the laws of the state of its formation.

c. Power, Authority and Non-Contravention. The Representing Party has the legal power and right to enter into and perform this Agreement and the transactions contemplated hereby. The consummation of the transactions contemplated by this Agreement does not violate or conflict with:

(i) any provision of the limited liability company agreement, operating agreement, or other governing documents of the Representing Party;

(ii) any agreement or instrument to which the Representing Party is a party or by which the Representing Party is otherwise bound; or

(iii) any judgment, order, license, permit, ruling or decree applicable to the Representing Party or where the Representing Party is as a party in interest or any law, rule, permit or regulation applicable to the Representing Party.

d. No Broker's Fees. The Representing Party has incurred no obligation contingent or otherwise, for any broker's, finder's or consultant's fees for which the other Party will be liable.

e. No Pending Claims. There is no suit, action, claim, investigation or inquiry by any person or entity or by any administrative agency or governmental authority and no legal, administrative or arbitration proceeding pending or, to the Representing Party's knowledge, threatened, against the Representing Party or any of its affiliates that has, or will, affect the Representing Party's ability to consummate the transactions contemplated herein. In addition, Seller represents and warrants to Buyer that there is no suit, action, or claim pending or, to Seller's knowledge, threatened, arising out of or related to the Properties or Seller's ownership of all or any portion thereof, including without limitation any claim or action alleging any breach, termination, or cancellation of any or all of the Properties.

f. No Bankruptcy Proceedings. There are no bankruptcy, reorganization or receivership proceedings pending, being contemplated by or, to the Representing Party's knowledge, threatened against the Representing Party.

g. Compliance with Anti-Bribery Laws. The Representing Party has not made, offered, authorized, requested, received or accepted or will not make, offer, authorize, request, receive or accept, in each case, with respect to the matters that are the subject of this Agreement, any payment, gift, promise or other advantage, whether directly or indirectly, through any Person, to or for the use or benefit of any Person, where such payment, gift, promise or advantage would violate (a) applicable anti-corruption Laws of the United States, (b) the US Foreign Corrupt Practices Act, or (c) the principles described in (i) the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions, signed in Paris on December 17, 1997 and effective on February 15, 1999 and (ii) such Convention's Commentaries.

5. Additional Representations and Warranties of Seller. Seller represents and warrants to Buyer as of the Execution Date and the Closing Date (unless a specific date is set forth below, in which case such specific date shall apply to such representation and warranty), as follows:

a. Consents and Preferential Purchase Rights. Except as set forth on Schedule 5(a), there are no restrictions on assignment (including requirements for consents from third parties to any assignment), preferential purchase rights, rights of first refusal or similar arrangements ("Consents and Preferential Rights") applicable to any or all of the Properties that, in each case, that are required to be obtained in connection with the transfer of any or all of the Properties by Buyer as contemplated hereby or the consummation of the other transactions contemplated by this Agreement. Any and all Consents and Preferential Rights described on Schedule 5(a) will be handled as outlined under Article 8(e) and (f) of this Agreement.

b. Taxes. All ad valorem, real property, severance and other similar taxes due and payable by Seller with respect of any or all of the Properties or production therefrom prior to the Effective Time have been paid, except ad valorem taxes for the accounting year in which the Closing occurs that are not yet due and payable. All tax returns relating to or prepared in connection with any such taxes that are required to be filed by Seller have been timely filed and all such tax returns are true, correct and complete in all material respects, and all such taxes that are or have become due have been timely paid in full, and Seller is not delinquent in the payment of any such taxes. Seller's interest in the Properties are not, or prior to Closing will not be, subject to tax partnership reporting for federal income tax purposes.

c. Contracts. Schedule 5(b) sets forth all Contracts of the following type (hereinafter collectively referred to as the "Material Contracts"): (i) any Hydrocarbon purchase and sale, transportation, gathering, treating, compressing, processing, dedication, storage, operating or similar Contract, (ii) any Contract that is a joint operating agreement, farmin agreement, farmout agreement, term assignment, participation agreement, area-of-mutual-interest agreement, communitization agreement, lease purchase agreement, prospect generation agreement or other similar agreement, to the extent, and then only to the extent, that such agreements contain any outstanding obligations required to be performed by, or that are otherwise binding on, Seller that will be binding on Buyer after Closing, (iii) any Contract that (A) cannot be terminated by Seller (or by Buyer after Closing) without penalty upon 30 days' or less notice or (B) involves an annual obligation or income more than Ten Thousand Dollars and No/100 ($10,000.00), (iv) any Contract that is an indenture, mortgage, loan, credit agreement, sale-leaseback, guaranty of any obligation, bond, letter of credit or similar financial Contract, and (v) any Contract that constitutes a partnership agreement, joint venture agreement or similar Contract. All of the Contracts are in full force and effect. Seller is not in material breach or default (and no situation exists that, with the passing of time or giving of notice would create a material breach or default) under any Contract, and, to Seller's knowledge, no material breach or default by any third party (or situation that, with the passing of time or giving of notice would create a material breach or default) exists or is threatened. True, complete and correct copies of all Contracts have been provided to Buyer on or prior to the Execution Date.

d. P&A. Except as set forth on Schedule 5(c), there exists no Well that (i) Seller is currently obligated by applicable law or contract to plug and abandon or (ii) has been plugged and abandoned in a manner that does not comply in all material respects with applicable laws and rules, regulations, permits, judgments, orders and decrees of any court or the applicable federal and state regulatory authorities.

e. Compliance with Laws. There has been no material violation of any law or regulation (excluding any Environmental Law (defined below) or regulation, which is expressly covered by Article 5(f) relating to the ownership of the Properties by Seller) or, to Seller's knowledge, the operation of the Properties by any other person.

f. Environmental.

(i) With respect to the Properties, Seller has not entered into, and, to Seller's knowledge, no predecessor to Seller has entered into, or is subject to, any material agreements, consents, orders, decrees, judgments, license or permit conditions, or other directives of governmental entities in existence as of the Execution Date that is based on any Environmental Laws or that require any remediation or change in the present conditions of the Properties.

(ii) Seller has not received written notice and has no knowledge of (a) any release, disposal, event, condition, activity or incident related to any hazardous substances that may impact any portion of the Properties; (b) any violations of, or liability under Environmental Laws with respect to the presence of any hazardous materials at, on, under, or emanating to or from any of the Properties; or (c) any actual or potential liability for the investigation or remediation of any disposal or release of hazardous materials at, on, under or emanating to or from any of the Properties.

(iii) True, complete and correct copies of all investigations, audits or other reports addressing environmental matters, if any, related to Seller's ownership of any portion of the Properties that are in Seller's possession or control have been provided to Buyer.

g. Current Commitments. Except as set forth in Schedule 5(d), as of the Execution Date, there are no outstanding authorities for expenditures or other written capital proposals proposed by Seller to any person or proposed by any person to Seller, to conduct operations (hereinafter referred to as the "AFEs") relating to the Properties that are in excess of Ten Thousand Dollars & No/100 ($10,000.00) (net to Seller's interest) and for which all of the activities anticipated in such AFEs have not been completed by the Execution Date.

h. Imbalances. Schedule 5(e) sets forth all imbalances associated with any of the Wells as of the Effective Time (hereinafter referred to as the "Imbalances").

i. Take-or-Pay. Seller is not obligated by virtue of any take-or-pay payment, advance payment or other similar payment, to deliver Hydrocarbons attributable to the Properties, or proceeds from the sale thereof, attributable to the Properties at some future time without receiving payment therefor at or after the time of delivery that would be binding on Buyer after Closing.

j. Non-Consent. Excluding the wells listed on Schedule 5(f), as of the Execution Date, no operations are being conducted or have been conducted on the Properties with respect to which Seller has elected to be a non-consenting party under the applicable operating agreement and with respect to which all of Seller's rights have not yet reverted to it.

k. Litigation. There are no proceedings pending or threatened in writing against Seller that affect the Properties or against the Properties, or that seeks to enjoin or otherwise prohibit any of the transactions contemplated in this Agreement.

l. Condemnation. Seller has not received any written notice of any pending or threatened condemnation of any portion of the Properties.

m. Liens. Other than Permitted Encumbrances (defined below), the Properties are not burdened by any outstanding liens, mortgages, security interests, pledges, charges or encumbrances, or other arrangements substantially equivalent thereto.

n. Fair Value. Seller hereby represents and warrants, and the Parties agree that: (i) the consideration given and to be exchanged by the Parties and to be received by Seller as provided in this Agreement shall constitute a contemporaneous or substantially contemporaneous exchange of equivalent value for the Properties transferred by Seller to Buyer, (ii) Seller and Buyer entered into this Agreement in good faith, (iii) no Party requires any further information, facts, research, evidence, or third party analysis or opinion in connection with the Parties' decision to execute this Agreement and (iv) no Party shall have the right to benefit in any manner, either directly or indirectly, from the assertion by any person or entity that the receipt by any Party to this Agreement of consideration to be exchanged pursuant to this Agreement, shall constitute or shall have constituted less than reasonably equivalent value for the consideration given pursuant to this Agreement, or a preferential payment with respect to any debts or obligations resolved pursuant to this Agreement.

6. Additional Representations and Warranties of Buyer. Buyer represents and warrants to Seller as of the Execution Date and as of the Closing Date (unless a specific date is set forth below, in which case such specific date shall apply to such representation and warranty), as follows:

a. Independent Evaluation. Buyer (i) is sophisticated in the evaluation, purchase, ownership of oil and gas properties and related facilities, (ii) is capable of evaluating, and hereby acknowledges that it has so evaluated, the merits and risks of the Properties, Buyer's acquisition, ownership, and its obligations hereunder, and (iii) is able to bear the economic risks associated with the Properties, Buyer's acquisition, ownership and its obligations hereunder. In making its decision to enter into this Agreement and to consummate the transactions contemplated hereby, (x) Buyer has relied or shall rely solely on the representations, warranties and covenants of Seller under this Agreement and the special warranty of title in the Assignment, its own independent investigation and evaluation of the Properties and the advice of its own legal, tax, economic, environmental, engineering, geological and geophysical advisors and the express provisions of this Agreement, and (y) subject to Seller's representations and warranties in Articles 4 and 5 and the special warranty of title in the Assignment, and subject to Seller's indemnification obligations in Article 12, Buyer has satisfied or shall satisfy itself through its own due diligence as to the environmental and physical condition of and contractual arrangements and other matters affecting the Properties.

b. Accredited Investor. Buyer is an "accredited investor," as such term is defined in Regulation D of the Securities Act of 1933, as amended, and will acquire the Properties for its own account and not with a view to a sale, distribution, or other disposition thereof in violation of the Securities Act of 1933, as amended, and the rules and regulations thereunder, any applicable state blue sky laws or any other applicable securities laws.

7. Disclaimer of Warranties. Other than the express representations and warranties of Seller contained in Articles 4 and 5 and the special warranty of Defensible Title in the Assignment (as hereinafter defined), Seller hereby expressly disclaims any and all other representations and warranties, express, implied, statutory or otherwise. Buyer agrees that the Properties are being sold by Seller "where is" and "as is," with all faults. Specifically as a part of the foregoing, but not in limitation thereof, Buyer acknowledges that Seller has not made and Seller expressly disclaims any representation or warranty, whether express, implied, under common law, by statute or otherwise, as to the title or condition of the Properties.

a. NORM and Hazardous Materials. Buyer acknowledges that the Properties have been used for exploration, development and production of Hydrocarbons and that there may be Hydrocarbons, produced water, wastes, Hazardous Materials or other materials located on or under the Properties or associated with the Properties. Buyer further acknowledges that the equipment and sites included in the Properties, and the materials and equipment located on the Properties, or included in the Properties may contain wastes, hazardous materials and/or NORM. Buyer acknowledges that NORM may affix or attach itself to the inside of Wells, materials and equipment as scale or in other forms. Buyer acknowledges that hazardous materials, NORM containing material, and/or wastes may have come in contact with the soil or other environmental media. Furthermore, Buyer acknowledges that special procedures may be required for the remediation, removal, transportation, disposal or other management or handling of soil, water, wastes, hazardous materials, and NORM from the Properties.

8. Title Matters.

a. Title Defects. As used herein, the term "Title Defect" shall mean (x) any lien, encumbrance, defect or failure of Seller's ownership of any or all of the Properties or lack of information provided by Seller evidencing Seller's ownership of any or all of the Wells, as shown on Exhibit B, that causes Seller not to have Defensible Title, or (y) other than any disclosures on Schedule 5(f), any suspended interest or non-consent/deemed non-consent election by Seller in a Well which causes Seller to not receive any revenue from such Well. No individual Title Defect shall be asserted by Buyer unless the amount of such individual Title Defect is in excess of Fifteen Thousand Dollars & No/100 ($15,000.00). As used herein, the term "Defensible Title" shall mean title to the Properties (on a property-by-property basis) that, subject to Permitted Encumbrances:

(i) entitles Seller to receive not less than the net revenue interest for each of the Wells, as set forth in Exhibit B;

(ii) obligates Seller to bear not more than the working interest for each of the Wells, as set forth in Exhibit B; and

(iii) will be free and clear of all mortgages, liens, defects and other encumbrances at the time of Closing.

As used herein, "Permitted Encumbrances" shall mean (i) royalty interests, overriding royalty interests, working interests and other payments on production to the extent they do not, individually or in the aggregate, reduce Seller's net revenue interest in any of the Properties from that specified in Exhibit B, as applicable; (ii) liens for taxes for which payment is not due; (iii) liens of mechanics, materialmen, warehousemen, landlords, vendors, and carriers and any similar liens arising by operation of law that, in each instance, arise in the ordinary course for sums not yet due; (iv) the terms of the Contracts, provided that such Contracts are listed on Schedule 5(c) and true, complete and correct copies thereof have been delivered to Buyer on or prior to the Execution Date; (v) easements, rights of way, servitudes, permits, and surface leases to the extent, individually or in the aggregate, such rights could not reasonably be expected to impair the ownership, operation, development, production or use of the Property or any portion thereof; (vi) plat restrictions, zoning laws, restrictive covenants and conditions, and building and other land use laws; (vii) mortgages, security interests, pledges and similar encumbrances burdening the Properties for which Seller obtains a full release prior to or contemporaneously with the Closing; and (viii) consents and approvals from governmental authorities for the assignment of the Properties to Buyer that are customarily and reasonably obtained after the assignment of properties similar to the Properties.

b. Notice of Title Defects. If Buyer determines that any or all of the Properties are subject to any Title Defect, then Buyer may deliver to Seller written notice of such Title Defects on or before December 13, 2017. Seller shall have the right, but not the obligation, to attempt to cure any asserted Title Defects prior to Closing. For any Title Defect not cured prior to Closing, Seller may either convey the Property subject to the Title Defect, either with or without indemnification, to Buyer at Closing, or remove the Property subject to the Title Defect from the Properties conveyed at Closing.

c. Title Defect Amount. If any Title Defect is not cured or removed prior to Closing and Buyer does not waive such Title Defect, then the Purchase Price payable at Closing by Buyer shall be reduced pursuant to Article 11(a)(iv) by an amount equal to the following (hereinafter referred to as the "Title Defect Amount"):

(i) if Buyer and Seller agree on the amount, then that amount shall be the Title Defect Amount;

(ii) if the Title Defect represents a decrease in (A) the actual net revenue interest for any Well, below (B) the net revenue interest set forth in Exhibit B for such Well, then the Title Defect Amount shall be the product of (y) the Allocated Value of such Well *multiplied by* (z) a fraction, the numerator of which is the net revenue interest shown on Exhibit B minus the actual net revenue interest for such Well and the denominator of which is the net revenue interest for such Well set forth in Exhibit B;

(iii) if the Title Defect represents Seller owning a working interest in a Well or Property which is larger than the Working Interest shown on Exhibit B, but only to the extent there is not a proportionate increase in the net revenue interest for such Well or Property, then the Title Defect Amount shall be the product of (y) the Allocated Value of such Well or Property *multiplied by* (z) a fraction, the numerator of which is the working interest increase and the denominator of which is the working interest shown for such Well or Property on Exhibit B.

(iv) if the Title Defect represents a suspended interest or non-consent/deemed non-consent election by Seller in a Well, other than those disclosed on Schedule 5(f), which causes Seller to not receive any revenue from such Well, the Title Defect Amount shall be the Allocated Value for such Well.

(v) if the Title Defect results from a lack of information provided by Seller to prove Seller's ownership of any or all of the Wells, as shown on Exhibit B, then (a) if Buyer is able to calculate a working interest and/or net revenue interest from the limited title documentation provided by Seller for such Well, the Title Defect amount shall be the Allocated Value for such Well *multiplied by* the difference between the working interest and/or net revenue interest shown on Exhibit B for such Well and the working interest and/or net revenue interest for such Well calculated by Buyer, or (b) if Buyer is unable to calculate a working interest and/or net revenue interest from the limited title documentation provided by Seller for such Well, the Title Defect amount shall be the Allocated Value for such Well.

(vi) if the Title Defect consists of a lien, encumbrance or other charge that is undisputed and liquidated in amount, the Title Defect Amount shall be the undisputed and liquidated amount necessary to be paid to remove the Title Defect; and

(vii) if the Title Defect is of a type not described above in subsections (i) through (v) above, then, in each case, the Title Defect Amount shall be determined by taking into account the Allocated Value of the Property so affected, the portion of Seller's interest in the Property affected by the Title Defect, the legal effect of the Title Defect, the potential economic effect of the Title Defect over the life of the affected Property, the values placed upon the Title Defect by Buyer and Seller and such other factors as are necessary to make a proper evaluation.

In the event Seller and Buyer cannot agree on Title Defect Amount pursuant to the foregoing, then (A) Buyer's good faith estimate of the Title Defect Amount (pursuant to the foregoing) shall be used for determining whether the conditions to Closing have been met (and the amount, if any, of any associated adjustment to be used for purposes of Closing) and (B) after Closing, the disputed amounts shall be finally resolved by a dispute resolution process using a single impartial arbitrator, with at least ten (10) years' experience in oil and gas title issues, to be selected by mutual agreement of the Seller and Buyer, or, in the event Buyer and the Seller cannot agree on an arbitrator, such arbitrator shall be selected by the Houston office of the American Arbitration Association. The arbitrator's decision as to the Title Defect Amount shall be final and not appealable. Buyer and Seller shall each bear its own attorneys' fees and costs in such arbitration and the fees of such arbitrator shall be split equally between Buyer and Seller. Such arbitration shall be conducted in Houston, Texas. Once appointed, the arbitrator shall not have any ex parte communications with any of the affected parties.

d. Notwithstanding anything to the contrary contained in this Agreement, no adjustment of the Purchase Price shall be made for Title Defects for which notices have been timely and otherwise validly delivered, unless the aggregate of all Title Defect Amounts, as determined in accordance with this Agreement, equals or exceeds two percent of the Purchase Price.

e. Consents. Prior to Closing, Seller shall use commercially reasonable efforts to obtain all consents set forth in Schedule 5(a) provided that Seller shall not be required to provide consideration or undertake obligations to or for the benefit of the holders of such consents. Seller shall deliver by certified mail return receipt requested written requests for such consents to the holder thereof. If (a) Seller fails to obtain a consent prior to the Closing, (b) the failure to obtain such consent would cause the assignment of such Property or Properties to Buyer to be void, and (c) the requirements of Article 8 are met, then the portion of the Property or Properties subject to such failed consent shall constitute a Title Defect (subject to the terms of Article 8), and Seller and Buyer shall have the right and remedies set forth in Article 8 with respect thereto.

f. Preferential Rights to Purchase. Prior to Closing, Seller shall use commercially reasonable efforts to comply with all preferential rights to purchase or similar rights relative to the sale of any of the Properties as set forth in Schedule 5(a), provided that Seller shall not be required to provide consideration or undertake obligations to or for the benefit of the holders of the Preferential Rights to Purchase. In accordance with this Agreement and the applicable Contracts, Seller shall deliver by certified mail return receipt requested written notices of the proposed transfer of any Properties subject to the Preferential Rights to Purchase to the holders of such rights. Seller shall promptly notify Buyer if any Preferential Rights to Purchase are exercised or if the requisite period has elapsed without said rights having been exercised. If a Third Party who has been offered an interest in any Property or Properties pursuant to a Preferential Right to Purchase elects, prior to Closing, to purchase such Property or Properties pursuant to the aforesaid offer, then the Property or Properties or part thereof so affected will be deemed an Excluded Asset or Assets, the Purchase Price will be reduced by the Allocated Value attributable thereto, and (subject to the other terms of this Agreement) the Parties shall proceed to Closing. If, as of the Closing Date, no waiver, consent or exercise notice has been received by Seller from the holder of a Preferential Right to Purchase and the time for exercising such Preferential Right to Purchase has not expired, then the Properties covered by the Preferential Right to Purchase will remain with Seller as Excluded Assets and the Purchase Price shall be adjusted by the Allocated Values of such Properties (or portions thereof). Upon the expiration of such Preferential Right to Purchase, to the extent such Preferential Right to Purchase has not been exercised, the Properties (or portions thereof) covered by such Preferential Right to Purchase shall be assigned to Buyer using a form of assignment substantially similar to the Assignment, and Buyer shall pay to Seller an amount equal to the Purchase Price adjustment referenced in the immediately foregoing sentence, subject to any adjustments for Title Defects.

9. Environmental Matters.

a. Environmental Law. As used herein, the term "Environmental Law" shall mean any statute, law, ordinance, rule, regulation, code, order, judicial writ, injunction or decree issued by any federal, state or local governmental authority in effect on or before the Effective Time relating to the control of any pollutant or protection of the air, water, land or environment or the release or disposal of hazardous materials, hazardous substances or waste materials, including, without limitation, the Clean Air Act, as amended, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Federal Water Pollution Control Act, as amended, the Occupational Safety and Health Act, as amended, the Resources Conservation and Recovery Act, as amended, the Safe Drinking Water Act, as amended, the Toxic Substances Control Act, as amended, the Superfund Amendment and Reauthorization Act of 1986, as amended, the Hazardous Materials Transportation Act, as amended, the Oil Pollution Act, as amended, the Emergency Planning and Community Right to Know Act, as amended, and comparable state and local laws addressing pollution or protection of the environment, biological or cultural resources and all regulations implementing the foregoing.

b. Environmental Conditions. As used herein, the term Environmental Conditions shall mean (a) any condition with respect to the air, soil, subsurface, surface waters, ground waters and/or sediment that causes Seller not to be in compliance with any Environmental Law or (b) any condition, environmental pollution, contamination or degradation on the Properties that would require remediation under any Environmental Law.

c. Notice of Environmental Conditions. If Buyer determines that any of the Properties which are not operated by Buyer are subject to any Environmental Condition that has associated with it a Remediation Amount greater than Fifteen Thousand Dollars & No/100 ($15,000.00), then Buyer may deliver to Seller written notice of such Environmental Condition on or before the date December 13, 2017. Seller shall have the right, but not the obligation, to attempt to cure any asserted Environmental Condition prior to Closing.

d. Remedies for Environmental Conditions. If any asserted Environmental Condition is not cured or removed prior to Closing and Buyer does not waive such asserted Environmental Condition, Seller shall have the option to (i) remove the portion of the Properties subject to such asserted Environmental Condition from the transaction contemplated by this Agreement and reduce the Purchase Price by the Allocated Value of the portion of the Properties so removed or (ii) reduce the Purchase Price by an amount equal to the most cost effective estimate reasonably available, consistent with industry standards, to perform any remediation required to comply with applicable Environmental Laws or to remedy the asserted Environmental Condition (hereinafter referred to as the "Remediation Amount") or (iii) with Buyer's consent, agree to fully indemnify Buyer for the asserted Environmental Condition.

e. Notwithstanding anything to the contrary contained in this Agreement, no adjustment of the Purchase Price shall be made for any asserted Environmental Conditions for which notices have been timely and otherwise validly delivered, unless the aggregate of all Remediation Amounts, as determined in accordance with this Agreement, equals or exceeds two percent (2%) of the Purchase Price.

10. Closing Obligations and Conditions.

a. Seller's Obligations. At the Closing, Seller shall do and deliver to Buyer the following:

(i) execute, acknowledge and deliver assignments of the Properties, which shall contain a special warranty of Defensible Title by, through and under Seller, but not otherwise (hereinafter collectively referred to as the "Assignment"), which shall be in substantially the form of Exhibit E, together with any federal, state, or other governmental agency form assignments necessary to transfer the Properties to Buyer;

(ii) Letters-In-Lieu to all Operators/Disbursers;

(iii) any consents and/or waivers of preferential rights to purchase, if any, Seller has obtained prior to Closing;

(iv) furnish evidence reasonably acceptable to Buyer of release of all liens, mortgages, security interests, pledges, charges or encumbrances or other arrangements substantially equivalent thereto (other than Permitted Encumbrances) affecting the Properties or any part;

(v) execute and deliver the Preliminary Settlement Statement in accordance with Article 11(b).

(vi) such other documents, instruments and agreements as Buyer reasonably requests as required to consummate the transactions contemplated by this Agreement.

b. Buyer's Obligations. At the Closing, Buyer shall do and deliver to Seller the following:

(i) execute, acknowledge and deliver the Assignment, together with the federal, state, or other governmental agency form assignments necessary to transfer the Properties to Buyer;

(ii) deliver by wire transfer to Seller an amount equal to the Purchase Price, as adjusted under Article 11(a); and

(iii) execute and deliver the Preliminary Settlement Statement in accordance with Article 11(b).

(iv) such other documents, instruments and agreements as Seller reasonably requests as required to consummate the transactions contemplated by this Agreement.

c. Buyer's Conditions. Buyer's obligation to proceed to Closing is, at Buyer's election, subject to the fulfillment of each of the following conditions, prior to or at Closing:

(i) All representations and warranties of Seller contained in this Agreement shall be true and correct in all material respects as of the Closing Date as if such representations and warranties were made as of the Closing Date, and Seller shall have, in all material respects, performed and satisfied all covenants and fulfilled all conditions required by this Agreement.

(ii) The aggregate downward adjustment to the Purchase Price to be applied at Closing due to any Title Defects and asserted Environmental Conditions does not exceed twenty percent (20%) of the Purchase Price.

(iii) Seller has executed and/or delivered, as applicable, all of the items listed in Article 10(a)(i), (ii), (iii) and (iv).

Notwithstanding anything to the contrary, Buyer may, in its sole discretion, terminate this Agreement if any or all of the conditions set forth in Article 10(c)(i), (ii), or (iii) have not been satisfied as of the Closing Date, in which case this Agreement shall be of no further force and effect, Seller shall return the Deposit to the Buyer, and neither Party shall have any further obligation or liability hereunder. Notwithstanding anything to the contrary, Buyer may, in its sole discretion, terminate this Agreement if the conditions set forth in Article 10(c)have not been satisfied as of January 31, 2018 (hereinafter referred to as the "Outside Date"), in which case this Agreement shall be of no further force and effect, Seller shall return the Deposit to the Buyer, and neither Party shall have any further obligation or liability hereunder.

d. Seller's Conditions. Seller's obligation to proceed to Closing is, at Seller's election, subject to the fulfillment of each of the following conditions, prior to or at Closing:

(i) All representations and warranties of Buyer contained in this Agreement shall be true and correct in all material respects as of the Closing Date as if such representations and warranties were made as of the Closing Date, and Buyer shall have, in all material respects, performed and satisfied all covenants and fulfilled all conditions required by this Agreement.

(ii) The aggregate downward adjustment to the Purchase Price to be applied at Closing due to any Title Defects and Environmental Conditions does not exceed twenty percent (20%) of the Purchase Price.

(iii) Buyer has executed and/or delivered, as applicable, all of the items listed in Article 10(b)(i), (ii), and (iii).

Notwithstanding anything to the contrary, Seller may, in its sole discretion, terminate this Agreement if any or all of the conditions set forth in Article 10(d)(i), (ii), or (iii) have not been satisfied as of the Closing Date, in which case this Agreement shall be of no further force and effect, Seller shall retain the Deposit, and neither Party shall have any further obligation or liability hereunder. Notwithstanding anything to the contrary, Seller may, in its sole discretion, terminate this Agreement if the conditions set forth in Article 10(d) have not been satisfied as of the Outside Date, in which case this Agreement shall be of no further force and effect, Seller shall return the Deposit to the Buyer, and neither Party shall have any further obligation or liability hereunder.

11. Certain Adjustments; Settlement Statement.

a. At the Closing, appropriate adjustments to the Purchase Price shall be made between Buyer and Seller so that:

(i) except as otherwise provided herein, all cost and expenses (including all ad valorem and property taxes, all drilling costs, all capital expenditures, all overhead charges under applicable operating agreements, all operating expenses and lease expenses):

(A) which are attributable, allocable, or incurred in the ownership, use, and/or operation of the Properties, prior to the Effective Time, shall be borne by Seller; and

(B) which are attributable, allocable, or incurred in the ownership, use, and/or operation of the Properties on or after the Effective Time, will be borne by Buyer;

(ii) all proceeds (net of applicable production, severance, and similar taxes) from the sale of Hydrocarbons:

(A) from the Properties and attributable to periods prior to the Effective Time, shall be received by Seller; and

(B) from the Properties and attributable to periods on or after the Effective Time will be received by Buyer; and

(iii) the Purchase Price is decreased by the Title Defect Amount for all uncured and unwaived Title Defects and the Remediation Amount for all uncured and unwaived asserted Environmental Conditions unless the Property related thereto is retained by Seller and not included in the Properties conveyed at Closing; and

(iv) the Purchase Price is decreased by an amount equal to the Allocated Value for the Properties excluded pursuant to this Agreement.

b. On or before December 15, 2017, Seller shall have delivered to Buyer, based upon the best information reasonably available to it, a schedule setting forth Seller's good faith estimate of the amount of the adjustments provided for in Article 9(a) (hereinafter referred to as the "Preliminary Settlement Statement"). Buyer and Seller shall have made all good faith efforts to agree on all adjustments in the Preliminary Settlement Statement prior to Closing, provided that if Buyer and Seller are unable to agree on such adjustments, then Buyer shall retain the right to dispute such matter in the manner set forth in Article 11(c). If the amount of adjustments so determined which would result in a credit to Buyer exceed the amount of adjustments so determined which would result in a credit to Seller, Buyer shall receive a credit, for the amount of such excess, against the Purchase Price to be paid at the Closing, and, if the converse is true, Buyer shall pay, at the Closing (in addition to amounts otherwise then owed), the amount of such excess.

c. On or before ninety (90) days after the Closing, Seller shall in good faith prepare a final settlement statement (hereinafter referred to as the "Final Settlement Statement") reflecting and itemizing all adjustments provided for in Article 11(a) (whether the same be made to account for expenses or revenues not considered in making the Preliminary Settlement Statement, or to correct errors made in the Preliminary Settlement Statement). Buyer shall respond in writing with any objections and proposed corrections to the Final Settlement Statement no later than thirty (30) days after the receipt of the Final Settlement Statement. If Buyer timely delivers objections and proposed corrections, then the Parties shall endeavor to use all commercially reasonable efforts to resolve all such objections and proposed corrections. If the Parties cannot resolve their differences within thirty (30) days of Seller's receipt of Buyer's objections and proposed corrections, then either Party may submit the matter for resolution by binding arbitration in accordance with Article 11(e). If Buyer does not respond to the Final Settlement Statement by signing or objecting to it in writing within thirty (30) days of receipt, the proposed Final Settlement Statement will be deemed conclusively approved by Buyer and neither party shall have any recourse or claim with respect to any item contained therein. Within three business days after the Parties' approval (or deemed approval) of the Final Settlement Statement, any amount owing thereunder by Seller to Buyer or Buyer to Seller shall be paid and delivered in readily available funds.

d. Each of Buyer and Seller shall share all information available to such Party and pertaining to or relating to the adjustments contemplated by this Article 11 with the other Party. Should any additional items which would be the subject of adjustments provided for in Articles 11(a) and 11(c) come to the attention of Buyer or Seller after such adjustments under this Article 11 are concluded, such adjustments shall be made by appropriate payments from Buyer to Seller or from Seller to Buyer within ten (10) days of the date such information becomes available and is verified by both Parties. The Parties agree that any adjustments pursuant to this Article 11 shall be treated as adjustments to the Purchase Price for federal income tax purposes.

e. Any arbitration conducted as a result of Article 11(c) shall be a dispute resolution process using a single impartial arbitrator, with at least ten years' experience in oil and gas accounting issues, to be selected by mutual agreement of the Seller and Buyer, or, in the event Buyer and the Seller cannot agree on an arbitrator, such arbitrator shall be selected by the Houston office of the American Arbitration Association. The arbitrator's decision as to the disputed amounts shall be final and not appealable. Buyer and Seller shall each bear its own attorneys' fees and costs in such arbitration and the fees of such arbitrator shall be split equally between Buyer and Seller. Such arbitration shall be conducted in Houston, Texas. Once appointed, the arbitrator shall not have any ex parte communications with any of the affected parties.

12. Indemnification.

a. Indemnification by Buyer. Except for the limited indemnification provided by Seller in Article 12(c) below, Buyer hereby assumes and agrees to fulfill, perform, pay and discharge (or cause to be fulfilled, performed, paid and discharge) all claims, obligations and liabilities, known or unknown, with respect to the Properties, regardless of whether such obligations or liability arose prior to, on, or after the Effective Time, including claims, obligations and liabilities relating in any manner to the Material Contracts, or the condition, use or ownership of the Properties. Buyer shall be solely liable and responsible to the Operators of the Properties for its proportionate share of all cost associated with the plugging and abandoning of all Wells and facilities now located or hereafter drilled or placed on the Properties by the Operators thereof, and any surface restoration or environmental clean-up or Environmental Liability associated therewith.

Buyer shall also indemnify and hold Seller harmless, it affiliates, and each of their respective officers, members, managers, partners, directors, employees, and representatives (hereinafter referred to as the "Indemnified Parties") against any and all liabilities, damages, losses, costs and expenses (including reasonable attorneys' and consultants' fees and expenses) incurred or suffered by the Indemnified Parties as a result of, relating to, or arising out of Buyer's desire to physically access the Properties prior to Closing, then any and all claims for personal injuries to or death of Buyer's employees, contractors, agents, consultants or representatives, or any damage to Buyer's property or others acting on behalf of Buyer, regardless of whether such claims arise out of or result in whole or in part from the condition of the Properties or Seller's (or its Affiliates, or its or their employees', agents', contractors', successors' or assigns') sole or concurrent negligence or fault; and any and all claims for personal injuries to or death of employees of Seller, its Affiliates or Third Parties, and damage to the Property or Properties of Seller, its Affiliates or Third Parties, to the extent caused by the negligence, gross negligence or willful misconduct of Buyer;

b. Survival of Buyer Representations, Warranties, Indemnification, Covenants and Agreements. The representations, warranties, indemnification, covenants and agreements of Buyer under this Agreement will survive Closing for a period of one (1) year.

c. Indemnification by Seller. Seller hereby retains and agrees to fulfill, perform, pay and discharge (or cause to be fulfilled, performed, paid and discharge) all claims, obligations and liabilities, known or unknown, with respect to the Properties, which obligations or liability arose prior to the Effective Time, including claims, obligations and liabilities relating in any manner to the Material Contracts, or the condition, use or ownership of the Properties but insofar and only insofar as to any and all properties not operated by Buyer and then only for a period of six months after Closing.

d. Survival of Seller Representations, Warranties, Covenants and Agreements. Except for the special warranty of title contained in the Assignment and Article 13(a), the representations, warranties, covenants and agreements of Seller Buyer under this Agreement will survive Closing for a period of six (6) months or such shorter period if expressly set forth in this Agreement. Any assertion or claim by Buyer under this Agreement must be made in a written notice delivered to Seller on or prior to the end of such six (6) months or shorter period. Failure of Buyer to make such assertion or claim within such period will be deemed a waiver by Buyer of such assertion or claim, and Seller shall have no liability for such assertion or claim which is not timely made.

e. Casualty or Condemnation Loss. If during the time period between the Execution Date and Closing, any portion of a Property or Properties is destroyed by a fire or other casualty or is taken in condemnation or under right of eminent domain (hereinafter collectively referred to as a "Casualty Loss"), Buyer will nevertheless be required to close and, at Seller's option either (a) the Purchase Price will be reduced by Seller's reasonable estimate of the amount of such Casualty Loss, such amount not to exceed the Allocated Value of such Property or Properties; or (b) the affected Property or Properties will be excluded from the transaction and deemed an Excluded Asset or Assets.

13. Miscellaneous.

a. Amendment to Exhibits and Schedules. The Buyer agrees that Seller shall have the continuing right until the Closing Date to add, supplement or amend the exhibits and schedules to this Agreement.

b. Taxes. All sales, use or other taxes and duties, levies or other governmental charges (including recording or similar fees and expenses) incurred by or imposed with respect to the property transfers undertaken pursuant to this Agreement shall be the responsibility of, and shall be paid by, Seller. Seller shall retain responsibility for, and shall bear and pay, all taxes assessed with respect to the ownership and operation of the Properties for any period ending prior to the Effective Time and Buyer shall be responsible for, and shall bear and pay, all taxes assessed with respect to the ownership and operation of the Properties for any period from and after the Effective Time.

c. Access. Upon execution of this Agreement and payment of the Deposit, Seller shall make available and grant access to Buyer and its representatives, employees, and consultants, during normal business hours, and at other mutually agreeable times prior to Closing, to (i) the Contracts, the Records, all title records (including, title opinions, curative title documents, and run sheets) and all revenue, cost accounting, payment and other similar records related to the Properties and (ii) the Leases, the Units, the Wells, and all other Properties. Buyer shall have such access rights up to three (3) days prior to Closing.

d. Operations Prior to Closing. Until the Closing or earlier termination of this Agreement, Seller shall: (i) notify Buyer of any claim or demand that might affect title to, or operation or use of, the Properties; (ii) notify Buyer of any changes, circumstances, facts or occurrences (whether or not within the control of any Seller, to the extent that such Seller has knowledge of the event) that if existing on the Execution Date would constitute a breach of any of the representations and warranties made by Seller herein, (iii) pay all taxes, costs and expenses attributable to its interest in the Properties as such taxes, costs and expenses become due and (iv) not (without Buyer's prior written consent): (A) abandon any Well unless such abandonment is required by applicable law (and then only after providing prior written notice thereof to Buyer), (B) transfer, sell, release or otherwise dispose of all or any portion of any of the Properties, (C) directly or indirectly initiate, solicit, encourage, continue to discuss, entertain or accept any offer or proposal regarding the possible acquisition by any person other than Buyer (including by way of a purchase of equity, purchase of assets or merger, consolidation or reorganization), of all or any portion of the Properties, (D) commence or consent to an operation, other than routine maintenance or emergency repairs, if the estimated cost of the operation exceeds Ten Thousand Dollars and No/100 ($10,000.00) in the aggregate, (E) create a lien, security interest or other encumbrance on any of the Properties, (F) amend any Lease or Contract or enter into any new contract or other agreement affecting the Properties, or (G) waive, compromise or settle any claim that could affect ownership, operation or value of any of the Properties by an amount exceeding Ten Thousand Dollars and No/100 ($10,000.00) net to the interest in the Properties to be acquired by Buyer pursuant to this Agreement.

e. Further Assurances. After the Closing, each Party at the request of the other and without additional consideration, shall execute and deliver, or shall otherwise cause to be executed and delivered, from time to time, such further instruments of conveyance or transfer, and do such further acts, as necessary to more fully and effectively convey and deliver the Properties to Buyer.

f. Entire Agreement. This Agreement, the documents to be executed hereunder, and the Exhibits and Schedules attached hereto constitute the entire and exclusive agreement between the Parties with respect to the subject matter hereof. No amendment, waiver or termination of this Agreement shall be binding unless in writing and executed by the Parties hereto and referencing this Agreement.

g. Notices. Any notice, communication, request, instruction or other document required or permitted hereunder must be in writing and delivered in person, by U.S. Mail postage prepaid, return receipt requested, Federal Express delivery (or other reputable delivery service), or electronic transmission (including electronic mail) (provided that notice by any electronic transmission is promptly followed with a copy delivered in person, by U.S. Mail postage prepaid, return receipt requested, or Federal Express delivery (or other reputable delivery service)), to the addresses of the applicable Party set forth below. Notices delivered in person or by electronic transmission shall be deemed received upon delivery, notices sent by U.S. Mail postage prepaid, return receipt requested, shall be deemed received on the date shown as received on the return notice, and notices sent by Federal Express delivery (or other reputable delivery service) shall be deemed received on the date shown on the confirmation of delivery.

Buyer:

Statoil Oil & Gas LP
6300 Bridge Point Pkwy
Building 2, Suite 100
Austin, TX 78730
Attention: Kate Beck
Bakken Asset Manager
Office Telephone: 512-427-3484
E-Mail: KACAP@statoil.com

Seller:

Earthstone Legacy Properties, LLC
1400 Woodloch Forest Drive
Suite 300
The Woodlands, TX 77380-1197
Attention: Christopher E. Cottrell
Executive Vice President Land & Marketing
Office Telephone: 281-771-3045
Office Fax: 832-823-0478
Mobile: 281-703-9219
E-Mail: chris@earthstoneenergy.com

With a copy to:

Earthstone Legacy Properties, LLC
1400 Woodloch Forest Drive
Suite 300
The Woodlands, TX 77380-1197
Attention: Robert Anderson
Executive Vice President Corporate Development & Engineering
Office Telephone: 281-771-3067
Office Fax: 832-823-0478
Mobile: 713-819-0104
E-Mail: Robert@earthstoneenergy.com

Either Party may, by written notice so delivered, change its address for notice purposes hereunder.

h. Choice of Law. Without regard to principles of conflicts of law, this Agreement shall be construed and enforced in accordance with and governed by the laws of the State of Texas.

i. Venue. Each Party irrevocably submits to the non-exclusive jurisdiction of any Texas state court or U.S. federal court sitting in Harris County, Texas in any dispute arising out of or relating to this Agreement, and hereby irrevocably agrees that all damages in respect of such dispute may be heard and determined in such Texas state or U.S. federal court.

j. Counterpart Execution. This Agreement may be executed in counterparts, all of which are identical and all of which constitute one and the same instrument. It shall not be necessary for Buyer and Seller to sign the same counterpart. The execution and delivery of this Agreement by Buyer and Seller may be evidenced by facsimile or other electronic transmission (including scanned documents delivered by email), which shall be binding upon Buyer and Seller.

k. Remedies. Notwithstanding anything herein to the contrary, neither Seller nor Buyer shall have any remedy arising under or related to this Agreement for any special, consequential or punitive damages; provided that any special, consequential, or punitive damages recovered by a third party (except an affiliate of the indemnified Party) shall be recoverable by a Party to the extent that such Party is entitled to indemnification for the matter with respect to which such damages are recovered.

l. Assignment. This Agreement may not be assigned, in whole or in part, by either Party without the express written consent of the other Party, which consent may be withheld in its sole and absolute discretion, and any assignment that is made without such consent shall be void.

m. Confidentiality. Neither Party may disclose the existence of this Agreement or any of the terms or provisions thereof, to any person, without the prior written consent of the other Party. Notwithstanding the foregoing, a Party may disclose, or permit the disclosure of information which would otherwise be confidential, if and to the extent that it is required by applicable law or any securities exchange or regulatory, governmental or other authority with relevant powers to which any Party is subject or submits, whether or not the requirement has the force of law.

n. Successors and Assigns. This Agreement shall be binding upon and benefit the Parties' respective successors and assigns, and the provisions hereof shall be covenants running with the land.

o. Third Party Beneficiaries. Except as expressly provided in Section 12, this Agreement is made solely for the benefit of the Parties hereto, and no other person shall have or claim or be entitled to enforce any rights, benefits or obligations under this Agreement.

p. Announcements. The Parties shall consult with each other with regard to all press releases and other announcements concerning (i) this Agreement or (ii) the operations within the Properties to the extent such press releases or announcements make reference to the name of the other Party and, except as may be required by law or the applicable rules and regulations of any governmental authority or stock exchange. Neither Party shall issue any such press release or make any other announcement without the prior written consent of the other Party, which consent shall not be unreasonably withheld.

q. Rules of Construction. As used in this Agreement, (i) any pronoun in masculine, feminine or neuter gender shall be construed to include all other genders, (ii) the term "including" shall be construed to be expansive rather than limiting in nature and to mean "including without limitation," except where the context clearly otherwise requires, (iii) each term defined in this Agreement in the singular shall include the plural of that term, and each term defined in this Agreement in the plural shall include the singular of that term, (iv) the words "this Agreement," "herein," "hereby," "hereunder," and "hereof," and words of similar import refer to this Agreement as a whole and not to any particular part of this Agreement unless the context clearly or expressly provides or indicates otherwise, (v) the term "person" means any individual, firm, corporation, company, partnership, joint venture, limited partnership, limited liability company, association, trust, estate, labor union, organization, governmental authority or any other entity, (vi) the term "affiliate" shall mean, with respect to any person, any person directly or indirectly through one or more intermediaries, controlling, controlled by or under common control with such person and "control", including the correlative terms "controlled" and "controlling", means the possession, directly or indirectly, of the power to direct or cause the direction of management or policies (whether through ownership of securities or any partnership or other ownership interest, by contract or otherwise) of a person and (vii) any reference herein to the "knowledge" or "awareness" of a Party shall mean the actual knowledge or awareness of any of such Party's owners, officers or members of its governing authority and the knowledge or awareness that a reasonably prudent person should have (whether by inquiry or otherwise) in the same or similar circumstances. The headings of the sections of this Agreement are for guidance and convenience of reference only and shall not limit or otherwise affect any of the terms and the conditions of this Agreement. No information or knowledge obtained or capable of being obtained by a Party or any of its representatives, whether through investigation, due diligence efforts or otherwise, shall affect or be deemed to modify any representation, warranty, covenant or other agreement of any Party contained herein. Each Party shall have the right to rely fully upon the representations, warranties, covenants and other agreements of the other Party contained in this Agreement. The Parties and their respective counsel participated in the review and/or preparation of this Agreement. In the event of any ambiguity in this Agreement, all Parties acknowledge and agree that no presumption shall arise based on the identity of the draftsman of any provision of this Agreement.

Signature Page Follows

Executed, on the Execution Date, by:

SELLER:

EARTHSTONE LEGACY PROPERTIES, LLC

By:	/s/ Christopher E. Cottrell
	Christopher E. Cottrell
	Executive Vice President Land & Marketing

BUYER:

STATOIL OIL AND GAS LP

By Statoil Oil & Gas Services Inc., Its General Partner

By:	/s/ Kate Beck
Name:	Kate Beck
Title:	Asset Manager

EXHIBITS AND SCHEDULES

Exhibit A:	Leases and Lands
Exhibit B:	Wells
Exhibit C:	Contracts
Exhibit D:	Easements
Exhibit E:	Assignment Form
Schedule 2.2:	Allocated Values
Schedule 5(a):	Consents and Preferential Rights To Purchase
Schedule 5(b):	Material Contracts
Schedule 5(c):	P&A
Schedule 5(d):	Current Commitments
Schedule 5(e):	Imbalances
Schedule 5(f):	Non-Consent Wells

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
Bold Energy III, LLC.	Texas
Bold 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 Earth Energy, Inc. for the year ended December 31, 2017, as well as in the notes to the financial statements included therein. We also hereby consent incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves report dated February 19, 2018 i Registration Statements on Form S-3 (File Nos. 333-205466, 333-213543 and 333-218277) and Form S-8 (File Nos. 333-210734 and 333-221248) filed wi the U.S. Securities and Exchange Commission.

Sincerely,

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

March 15, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 15, 2018, 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, 2017. We consent to the incorporation by reference of said reports in the Registration Statements of Earthstone Energy, Inc. on Form S-3 (File Nos. 333-213543, 333-205466 and 333-218277) and on Form S-8 (File Nos. 333-210734 and 333-221248).

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2018

Exhibit 23.3

Consent of Independent Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements of Earthstone Energy, Inc. on Form S-3 (File No. 333-205466, 333-213543, and 333-218277) and on Form S-8 (File No. 333-210734 and 333-221248) 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, 2017, 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, 2018

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, 2018

/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, 2018

/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, 2017, 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, 2018

/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, 2017, 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, 2018

/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, 2017

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, 2017

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

February 19, 2018

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, 2017

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 February 19, 2018 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 within the United States. This report utilized an effective date of December 31, 2017, 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). This report was prepared for the inclusion as an exhibit in a filing made with the 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 Undeveloped	Total Proved
Net Reserves					
Oil	- Mbbl	10,854.1	1,095.0	35,378.0	47,327.1
Gas	- MMcf	21,387.2	1,948.4	67,752.0	91,087.6
NGL	- Mbbl	3,753.9	369.2	13,344.7	17,467.9
Net Revenue					
Oil	- M$	533,587.9	54,382.8	1,730,403.4	2,318,374.3
Gas	- M$	56,298.1	5,038.8	171,695.7	233,032.6
NGL	- M$	84,637.0	8,748.5	304,196.6	397,582.0
Severance Taxes	- M$	34,561.2	3,535.7	114,430.6	152,527.5
Ad Valorem Taxes	- M$	19,186.7	1,939.0	62,755.9	83,881.7
Operating Expenses	- M$	170,346.4	12,347.1	273,117.7	455,811.3
Other Deductions	- M$	31,933.2	2,582.0	64,208.8	98,724.0
Abandonment Costs	- M$	4,112.1	365.9	2,866.4	7,344.3
Investments	- M$	0.0	11,176.8	665,916.5	677,093.2
Net Operating Income (BFIT)	- M$	414,383.3	36,223.6	1,023,000.0	1,473,607.3
Discounted @ 10%	**- M$**	**253,156.3**	**20,637.0**	**324,848.0**	**598,641.4**

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, 2017 were $51.34/BBL and $2.976/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 (Bloomberg) during 2017 and the base gas price is based upon Henry Hub spot prices (Platts Gas Daily) during 2017. NGL prices were adjusted on a per-property basis and averaged 46.4% of the net oil price on a composite basis. Prices were not escalated in the SEC scenario.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differential, treating cost, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $48.986 per barrel for oil, $2.558 per MCF for natural gas and $22.761 per barrel for NGL. All economic factors were held constant in accordance with SEC guidelines.

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 non-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 188 proved undeveloped locations, of which 168 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. However, the net cost of plugging and the salvage value of equipment at abandonment have been included herein.

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. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

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

W. Todd Brooker, P.E.
President

Robert P. Bergeron, Jr., P.E.
Reservoir Engineer

APPENDIX
Explanatory Comments for Individual Tables

HEADINGS

Table I
Description of Table Information
Identity of Interest Evaluated
Property Description – Location
Reserve Classification and Development Status
Effective Date of Evaluation

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 positions.
(16)	Revenue derived from other sources not included in column (12) through column (15); may include revenue from electrical sales, pipeline gas transportation, 3rd party saltwater disposal, etc.
(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)	Abandonment Costs are cost for plugging and the salvage value of equipment at abandonment.
(26)	Overhead Expenses are contractual non-COPAS headquarters "G&A" overhead charges for operated wells.
(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.
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) **Probable reserves**. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

“(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

“(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

“(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

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

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

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

"Note to paragraph (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)."