Table of Contents

Index to Financial Statements

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2016

OR

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

COMMISSION FILE NUMBER 000-33275

Warren Resources, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**11-3024080** (I.R.S. Employer Identification No.)
5420 LBJ Freeway, Suite 600 **Dallas, Texas** (Address of principal executive offices)	**75240** (Zip Code)

Registrant's telephone number, including area code: (214) 393-9688

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

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, $.01 par value per share	None

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☒

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

The aggregate market value of the registrant's common stock held by non- affiliates of the registrant on June 30, 2016 was approximately $1.6 million.

The number of shares of registrant's common stock outstanding as of April 7, 2017 was 10,000,000 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

The registrant intends to file an amendment on Form 10-K/A not later than 120 days after the close of the fiscal year ended December 31, 2016. Portions of such amendment are incorporated by reference into Part III of this report on Form 10-K.

WARREN RESOURCES, INC.

FORM 10-K

TABLE OF CONTENTS

As used in this document, “Warren”, “the Company”, “we”, “us” and “our” refer to Warren Resources, Inc. and its subsidiaries. The term “Warren E&P” refers to our wholly owned subsidiary Warren E&P, Inc.

Warren’s logo is a trademark or service mark of Warren. Other trademarks or service marks appearing herein are the property of their respective holders.

For abbreviations or definitions of certain terms used in the oil and gas industry and in this annual report on Form 10-K, please refer to the section entitled “Glossary of Abbreviations and Terms”.

PART I

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The statements contained in this annual report on Form 10-K that are not historical are “forward-looking statements,” as that term is defined in 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”), that involve a number of risks and uncertainties.

These forward-looking statements include, among others, the following:

- our ability to successfully and economically acquire, explore, develop and produce oil and natural gas resources;
- our ability to obtain governmental and other permits and approvals;
- the actual or potential impact of environmental and other governmental regulation;
- our exploration and development drilling prospects, inventories, projects and programs;
- our oil and natural gas reserve estimates;
- volatility in commodity prices and market conditions for oil and natural gas;
- our liquidity and ability to finance our acquisition, exploration and development operations and activities;
- our future production, revenue, operating costs and results of operations;
- the cost and availability of experienced labor;
- our business and growth strategies;
- our identified drilling locations;
- availability and costs of drilling rigs, equipment and field services;
- our ability to make and integrate acquisitions; and
- our ability to effectively manage our areas of operations.

These statements may be found under “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Business and Properties” and other sections of this annual report on Form 10-K. Forward-looking statements are typically identified by use of terms such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of such terms or other comparable terminology, although some forward-looking statements may be expressed differently.

The forward-looking statements contained in this annual report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this annual report on Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to a number of factors, including:

- commodity price volatility;
- potential adverse effects of our emergence from Chapter 11 Cases (as defined below) on our liquidity, results of operations, brand or business prospects and our ability to operate our business;
- the effect of the bankruptcy filing on our business and the interest of various creditors, equity holders and other constituents;
- domestic and worldwide economic conditions;
- potential adverse changes in general economic conditions, including performance of financial markets, interest rates and unemployment rates;
- unsuccessful drilling or operating activities;

- the inability to develop our reserves through exploration and development activities;
- the potential impact of environmental and other governmental regulation, including delays in obtaining governmental and other permits and approvals, and impacts on competing energy sources as well as on natural gas;
- possible legislative or regulatory changes, including severance or production tax regimes, hydraulic-fracturing regulation, additional drilling and permitting regulations, oil and natural gas derivatives reform, changes in state, federal and foreign income taxes, environmental regulation (including with respect to climate change and greenhouse gas emissions), environmental risks and liability under federal, state, foreign and local environmental and other laws and regulations;
- the failure to obtain sufficient capital resources to fund our operations;
- our ability to service and repay our debt;
- the extent to which natural gas markets in the United States become integrated with global natural gas markets through the approval and development of infrastructure supporting the export of liquefied and other natural gas;
- a decline in oil or natural gas production;
- changes in the localized and global supply and demand fundamentals of natural gas and oil and transportation availability;
- incorrect estimates of reserve quantities, operating costs and capital expenditures;
- increases in the cost of drilling, completion and gas gathering or other costs of production and operations;
- hazardous and risky drilling operations; and
- an inability to grow.

You should also consider carefully the statements under other sections of this annual report on Form 10-K, which address additional factors that could cause our actual results to differ from those set forth in the forward-looking statements.

All forward-looking statements speak only as of the date of this annual report on Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Glossary of Abbreviations and Terms

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

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

Bbl/d. One Bbl per day.

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Bcfe. One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

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

Coalbed methane (CBM). Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and produced by non-traditional means.

Completion. The installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

Dewatering. A coalbed methane well typically begins dewatering with almost all water production and little, or no, natural gas production. The continuous production of water from a well that is dewatering reduces the water reservoir pressure on the coals. The reduced reservoir pressure enables the release of the gas within the coal to the wellbore. This results in an increase in the amount of gas production relative to the amount of water production. Dewatering ceases when peak gas production is reached.

Dry hole or well. An exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Environmental assessment (EA). A public document that analyzes a proposed federal action for the possibility of significant environmental impacts. The analysis is required by the National Environmental Policy Act. If the environmental impacts will be significant, the federal agency must then prepare an environmental impact statement.

Environmental impact statement (EIS). A detailed statement of the environmental effects of a proposed action and of alternative actions that is required for all major federal actions.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

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

Farm-out or Farm-in. An agreement where the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out.

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

Fracturing. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or gases may more easily flow through the formation.

Gross Acres. The total acres in which we own any amount of working interest.

Gross Wells. The total number of producing wells in which we own any amount of working interest.

Horizontal Drilling. A drilling operation in which a portion of the well is drilled horizontally or laterally within a productive or potentially productive formation.

Identified drilling locations. Total gross locations specifically identified and scheduled by management as an estimation of our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

Injection Well or Injector. A well which is used to place water, liquids or gases into an underground zone to assist in maintaining reservoir pressure, enhancing recoveries from the field, or disposal of produced water.

Intangible Drilling and Development Costs. Expenditures made for wages, fuel, repairs, hauling and supplies necessary for the drilling or recompletion of an oil or gas well and the preparation of such well for the production of oil or gas, but without any salvage value, which expenditures are generally accepted in the oil and gas industry as being currently deductible for federal income tax purposes. Examples of such costs include:

- ground clearing, drainage construction, location work, road building, temporary roads and ponds, surveying and geological work;
- drilling, completion, logging, cementing, acidizing, perforating and fracturing of wells;
- hauling mud and water, perforating, swabbing, supervision and overhead;
- renting horizontal tools, milling tools and bits; and
- construction of derricks, pipelines and other physical structures necessary for the drilling or preparation of the wells.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter and explore for, drill for, produce, store and remove oil and natural gas from the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

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

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcf/d. One Mcf per day.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas at standard atmospheric conditions.

MMcf/d. One MMcf per day.

MMcfe. One million cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

MMcfe/d. One MMcfe per day.

Net acres. Gross acres multiplied by the percentage working interest owned by Warren.

Net production. Production that is owned by Warren less royalties and production due others.

Net Revenue Interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Net wells. The sum of all of Warren's full and partial well ownership interests (i.e., if we own 25% percent of 100% working interest in eight producing wells, the total net producing well count would be two net producing wells).

Number of Wells Drilled. Refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiatied.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

Permeability. A measure of the resistance or capacity of a geologic formation to allow water, natural gas or oil to pass through it.

PDP. Proved developed producing.

PDNP. Proved developed nonproducing.

Plugging and abandonment. 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 or to the surface. Regulations of all states require plugging of abandoned wells.

Productive Well. An exploratory, development, or extension well that is not a dry well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed operating and production expenses and taxes.

Proved developed non-producing reserves. Proved developed reserves that do not qualify as proved developed producing reserves, including reserves that are expected to be recovered from (i) completion intervals that are open at the time of the estimate, but have not started producing, (ii) wells that are shut in because pipeline connections are unavailable or (iii) wells not capable of production for mechanical reasons.

Proved developed producing reserves. Reserves that are being recovered through existing wells with existing equipment and operating methods.

Proved developed reserves. This term means "proved developed oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X, and refers to reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves or proved oil and gas reserves. This term means "proved oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X and refers to the 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.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

PUD. Proved undeveloped.

Proved undeveloped reserves. 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.

PV-10 Value. The PV-10 of reserves is the present value of estimated future revenues to be generated from the production of the reserves net of estimated production and future development costs and future plugging and abandonment costs, using the twelve-month arithmetic average of the first of the month prices without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, without non- property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%. See Footnote (1) to the table under oil and natural gas reserves-proved reserves in Items 1 and 2.

Re-entry. Entering an existing well bore to redrill or repair.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserves. This term is defined in Rule 4-10 of SEC Regulation S-X and refers to 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.

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

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

Secondary Recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and water flooding are examples of this technique.

Shut in. A well suspended from production or injection but not abandoned.

Spacing. The number of wells which can be drilled on a given area of land under applicable laws and regulations.

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a ten percent annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas producing activities contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

Tangible Drilling Costs. Expenditures necessary to develop oil or gas wells, including acquisition, transportation and storage costs, which typically are capitalized and depreciated for federal income tax purposes. Examples of such expenditures include:

- well casings;
- wellhead equipment;

- water disposal facilities;
- metering equipment;
- pumps;
- gathering lines;
- storage tanks; and
- gas compression and treatment facilities.

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

Ultimate recovery. The total expected recovery of oil and gas from a producing well, leasehold, pool or field.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

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

Workover. Remedial operations on a well conducted with the intention of restoring or increasing production from the same zone, including by plugging back, squeeze cementing, reperforating, cleanout and acidizing.

Items 1 and 2: Business and Properties

Overview

Warren Resources, Inc. is an independent energy company engaged in the exploration, development and production of domestic onshore crude oil and gas reserves. We focus our efforts primarily on the development of our waterflood oil recovery properties in the Wilmington field within the Los Angeles Basin of California, our position in the Marcellus Shale in northeastern Pennsylvania and our coalbed methane, or CBM, natural gas properties located in the Washakie Basin in southwestern Wyoming.

As of December 31, 2016, we owned natural gas and oil leasehold interests in approximately 105,897 gross (80,099 net) acres, approximately 66% of which are undeveloped. Substantially all our undeveloped acreage is located in Wyoming. We have identified approximately 140 gross drilling locations in our Wilmington field units. Additionally, we have identified approximately 140 gross drilling locations on our acreage in Wyoming, primarily on 80-acre well spacing and 74 gross drilling locations in the Marcellus Shale.

As of December 31, 2016, we had estimated net proved reserves of 25.4 MMBoe, with a PV-10 Value of $28.4 million, based on a reserve report prepared by Netherland, Sewell & Associates, Inc. These estimated net proved reserves include 4.7 MMBbls in our Wilmington units (19%), 93.5 Bcf in our Marcellus field in Pennsylvania (61%) and 28.4 Bcf in our CBM program in the Washakie Basin (19%). These estimated net proved reserves are located on approximately 30% of our total net acreage.

As of December 31, 2016, we had interests in 668 gross (507.7 net) producing wells and are the operator for 87% of these wells. For December of 2016, our average daily production was 13.7 MBoe/d gross (11.1 MBoe/d net). For 2017, we have a projected total capital expenditure budget of approximately $8.5 million.

The Company was incorporated on June 12, 1990 as a Delaware corporation for the purpose of acquiring and developing Oil & Gas Properties. The Company was incorporated under the laws of the state of Maryland prior to its reincorporation in the state of Delaware effective October 5, 2016.

The Company's principal executive offices are located at Two Lincoln Centre, 5420 LBJ Freeway, Suite 600, Dallas, Texas 75240 and the Company's telephone number is (214) 393-9688. Warren makes available free of charge on its website at *www.warrenresources.com* its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the Securities and Exchange Commission ("SEC"). Any materials that the Company has filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington D.C. 20549 or accessed via the SEC's website address at *www.sec.gov*. The public may also obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

Reorganization Under Chapter 11 and Emergence from Bankruptcy

On June 2, 2016, the Company and certain of its wholly owned subsidiaries (together with the Company, the "Debtors") filed voluntary petitions (the "Bankruptcy Petitions") for reorganization (the "Chapter 11 Cases") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"), Case No. 16-32760. The Debtors continued to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The subsidiary Debtors in the Chapter 11 Cases were Warren E&P, Inc. ("Warren E&P"), Warren Resources of California, Inc. ("Warren California"), Warren Marcellus, LLC ("Warren Marcellus"), Warren Energy Services, LLC and Warren Management Corp. (together, the "Chapter 11 Subsidiaries"), which represent all subsidiaries of the Company. On September 14, 2016, the Bankruptcy Court entered an order (the "Confirmation Order") approving the Plan of Reorganization of Warren Resources, Inc. and Its Affiliated Debtors (as amended and supplemented, the "Plan"). On October 5, 2016 (the "Effective Date"), the Plan became effective pursuant to its terms, and the Debtors completed their reorganization under the Bankruptcy Code.

The description of the Plan can be found in its entirety by reference to the full text of the Confirmation Order, filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission (the "SEC") on September 20, 2016.

The reorganization under Chapter 11 substantially reduced indebtedness and restructured the Company's balance sheet. Throughout the course of the Chapter 11 reorganization, we were able to conduct normal business activities and pay associated obligations for the period following the bankruptcy filing and paid certain per-petition obligations, including employee wages and benefits, goods and services provided by certain vendors, transportation of our production, and royalties and costs incurred on the Company's behalf by other working interest owners. As a result of the reorganization, we now have an improved capital structure and enhanced financial flexibility.

Fresh Start Accounting

The Company elected to apply fresh start accounting effective September 30, 2016, to coincide with the timing of its normal fourth quarter reporting period, which resulted in Warren becoming a new entity for financial reporting purposes. The Company evaluated and concluded that events between October 1, 2016 and October 5, 2016 were immaterial and the use of an accounting convenience date of September 30, 2016 was appropriate. As such, fresh start accounting is reflected in the accompanying consolidated balance sheet as of December 31, 2016 and related fresh start adjustments are included in the accompanying statement of operations for the period from January 1, 2016 through September 30, 2016 (Predecessor).

As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the financial statements after September 30, 2016 (Successor) will not be comparable with the financial statements prior to that date. References to the "Successor" relate to Warren subsequent to September 30, 2016. References to the "Predecessor" refer to Warren on and prior to September 30, 2016.

Business Strategy

The principal elements of our business strategy are designed to grow our oil and gas reserves, production volumes and cash flows at a positive return on invested capital. We intend to accomplish this by focusing on the following key strategies:

- ***Acquire Additional Assets.*** We will continue to review asset acquisitions that meet our economic criteria with a focus on development potential of oil and gas properties that can be developed at a reasonable cost.
- ***Exploit Existing Properties Through the Drillbit.*** We seek to maximize the value of our existing asset base by developing properties that have production and reserve growth potential while also attempting to control production costs. We have identified a total of approximately 140 gross oil well drilling locations in our Wilmington Field oil properties, 74 gross drilling locations in the Marcellus Shale and 140 gross drilling locations in our Wyoming CBM properties, which we plan to develop using capital expenditures within cashflow from operations. Our drilling locations are located in mature fields with established production profiles and supported by existing infrastructure and end markets. Drilling locations may not have reserves associated with them at this time due to economic constraints.
- ***Increase Production and Increase Proved Developed Producing Reserves from our Existing Oil and Gas Asset Base.*** We intend to increase our proved reserves and production in future years by drilling wells on our properties with undeveloped reserves or with resource potential, which represents approximately 66% of our acreage position at December 31, 2016.
- ***Invest our Capital in a Disciplined Manner and Maintain a Strong Financial Position.*** We focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or proved reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities in all commodity cycles. Our capital programs are generally developed to be funded through internally generated cash flows and the use of our credit line, but we also may obtain alternative sources of capital to develop our assets through partnerships, joint ventures or other investment opportunities with third parties or additional debt or equity. We hedge a portion of our production and generally utilize long-term sales contracts to maintain a strong financial position and provide us with cash flow necessary for the development of our assets.
- ***Reduce Costs Through Economies of Scale and Efficient Operations.*** As we continue to increase our production and develop our existing properties, we expect that our cost structure will benefit from economies of scale. We seek to exert more control over costs and timing in our exploration, development, production and operating activities.
- ***Control Operations and Costs in Depressed Commodity Price Environment.*** We seek to serve as the operator of the wells in which we have a significant interest. As the operator, we are better positioned to control the timing and plans for future enhancement and exploitation efforts, the costs of drilling, completing, enhancing and producing the wells, and the technical expertise to take advantage of geological and operational opportunities. We believe this enables us to maximize both production volumes and wellhead prices.

Business Strengths

Balanced Asset Portfolio. Since 1999, we have grown our asset base and diversified our production through California oil property acquisitions in the Los Angeles Basin and natural gas property acquisitions in the Atlantic Rim Prospect, Washakie Basin in southwestern Wyoming and the Marcellus Shale in northeastern Pennsylvania. We believe our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in natural gas and oil prices, as well as area economics.

Long -Lived Proved Reserves with Stable Production Characteristics. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics, with a ratio of total estimated proved reserves to production of approximately 6 years.

Low-Risk Multi-Year Drilling Inventory in Established Resource Plays. Most of our drilling locations are located in proven resource plays that possess low geologic risk and lead to predictable drilling results. We have identified approximately 140 gross drilling locations in our California assets that have an average vertical depth of less than 4,000 feet and are located in areas where we are an established driller and producer and 74 gross drilling locations in the Marcellus Shale.

Operational control and financial flexibility. As of December 31, 2016, we were the operator of record for 87% of our producing wells. We generally prefer to retain operating control over our properties, which allows us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary, which allows us a significant degree of flexibility to adjust the size of our capital budget. We limited our capital expenditure budget for 2017 to an estimated $8.5 million, compared to $5.1 million of development cost in 2016. Because of the decline in oil and gas prices, we have chosen to finance our 2017 capital expenditure budget primarily through our internally generated operating cash flows.

Experienced management and operational teams. Our core team of technical staff and operating managers have broad industry experience, including experience in horizontal and directional drilling, waterflood recovery operations, Marcellus development and CBM development and completion. Each of our operational teams in our Pennsylvania, California and Wyoming projects has extensive operating experience in their respective geographic areas. We continue to utilize technologies and waterflood recovery practices that will allow us to optimize production and improve the ultimate recoveries of crude oil on our California properties.

Areas of Development Activities

Our development activities are focused primarily on waterflood oil recovery projects in the Wilmington field in California, CBM projects in Wyoming and our Marcellus Shale project that utilizes horizontal drilling and hydraulic fracturing techniques to develop dry natural gas. The table below highlights our main areas of activity as of December 31, 2016 (Successor):

Area	Gross Acres	Net Acres	Net Undeveloped Acreage
Atlantic Rim Project, Wyoming	90,143	70,010	47,171
Wilmington Field, California	2,476	2,460	1,211
Marcellus, Pennsylvania	6,513	5,288	2,697
Pacific Rim Project, Wyoming	197	87	87
Other(1)	6,568	2,254	1,317
Total	105,897	80,099	52,483

(1) Includes conventional oil and gas properties located primarily in New Mexico and Texas.

California Projects

Wilmington Townlot Unit

Our Wilmington Townlot Unit (“WTU”) is located in the Wilmington field within the Los Angeles Basin of California. The WTU, a unitized oil field consisting of 1,440 gross (1,424 net) acres, has produced more than 156 million barrels of oil from primary and secondary production. All the working interests in the WTU are subject to the terms and provisions of a unit operating agreement. We own an approximate 98.9% undivided working interest in the WTU.

The net average oil production for the three months ended December 31, 2016, was approximately 1,698 barrels of oil per day (“Bbls/d”), in the WTU, compared to 2,018 Bbls/d net production during three months ended December 31, 2015. As of December 31, 2016, there were 186 gross (184 net) productive wells. Productive wells include producing wells and wells mechanically capable of production. In addition, estimated proved reserves as of December 31, 2016 were 5.8 MMbbls gross (4.7 MMbbls net), of which approximately 85% are PDP or PDNP and 15% are PUDs.

North Wilmington Unit

The North Wilmington Unit ("NWU"), a unitized oil field consisting of 1,036 gross and net acres, is located in the Wilmington oil field adjacent to our existing WTU. All working interests in the NWU are subject to the terms and provisions of a unit operating agreement. We own a 100% working interest and an approximate 84.7% net revenue interest in the NWU, including existing wells, certain equipment and certain surface properties.

The net average oil production for the three months ended December 31, 2016 was 329 Bbls/d in the NWU, compared to 462 Bbls/d net production during three months ended December 31, 2015. As of December 31, 2016, there were 46 gross and net productive wells in the NWU. There were no estimated proved reserves as of December 31, 2016.

Pennsylvania Marcellus Shale Project

Our Pennsylvania properties consist of a concentrated, contiguous acreage position located in Wyoming County, Pennsylvania in the northeast portion of the Marcellus Shale play. We operate approximately 6,513 gross (5,288 net acres in the Lower Marcellus Shale and 3,966 net acres in the Upper Marcellus Shale). We hold an approximate 75% working interest and an approximate 60% net revenue interest in these Lower Marcellus assets and an approximate 56% working interest and 45% net revenue interest in these Upper Marcellus assets. The Marcellus assets net average gas production for the three months ended December 31, 2016 was approximately 44.4 MMcfe/d. We have 34 gross (25 net) productive wells, three of which are located in the Upper Marcellus and the remainder in the Lower Marcellus. We plan to complete one additional drilling location in the Lower Marcellus. Estimated net proved reserves as of December 31, 2016 were 93.5 Bcfe, of which 89.6% are PDP. The assets include a robust and scalable infrastructure system that will enable us to further our development of the Marcellus Assets, including a gathering and compression system, takeaway capacity to end markets, a significant local customer, and abundant water supply.

Atlantic Rim Projects in the Washakie Basin, Wyoming

The Washakie Basin is located in the southeast portion of the Greater Green River Basin in southwestern Wyoming and represents our largest acreage position. As of December 31, 2016, we owned 90,143 gross (70,010 net) acres prospective for CBM development in this area, of which 47,171 net acres were undeveloped.

The net average gas production for our Wyoming assets for the three months ended December 31, 2016 was approximately 11.7 MMcfe/d. We have 386 gross (248.7 net) productive wells in the Washakie Basin. Estimated net proved reserves as of December 31, 2016 were 28.4 Bcfe, of which 100% are PDP and PDNP.

Atlantic Rim Project

Our Atlantic Rim project comprises approximately 90,143 gross (70,010 net) acres on the eastern rim of the Washakie Basin. As of December 31, 2016, we had drilled a total of 316 wells. Currently, we are developing our acreage in the Atlantic Rim project within the Spyglass Hill Unit.

Spyglass Hill Unit

Warren operates the U.S. Bureau of Land Management (the "BLM") approved Spyglass Hill Unit in the Atlantic Rim area, which covers approximately 113,290 total gross acres (the "Unit"). Effective September 11, 2016, the Spyglass Hill Unit contracted down to 28,948 gross acres, which contains three Participating Areas. All producing wells within Spyglass Hill Unit are situated within Grace Point Participating Area, Sun Dog Participating Area or Doty Mountain Participating Area.

Spyglass Hill Unit, Wyoming Participating Areas	Total Acres in Participating Area	Warren Gross Acres in Participating Area	Warren Net Acres in Participating Area
"A" Grace Point	6,362	6,082	5,157
"B" Doty Mountain	11,495	10,335	9,118
"C" Sun Dog	11,091	10,406	7,689
Total	28,948	26,823	21,964

Warren also owns interests in undeveloped leases in the southern portion of the Atlantic Rim Project, which are prospective for multiple deep formations. These leases are perpetuated by production or commitment to the Unit. Since the Unit contracted effective September 11, 2016, these leases were given a two year extension under the Spyglass Hill Unit Agreement. If the leases are not producing in paying quantities or committed to a new unit by September 11, 2018, the leases will expire.

Midstream Assets

Warren owns a 100% interest in the gas gathering, compression and pipeline midstream assets which serve the Atlantic Rim Project. The midstream assets consist of gathering and compression equipment and a 59 mile long pipeline that transports gas from the gathering systems throughout the Spyglass Hill Unit area to the Wyoming Interstate Company (WIC) interstate gas transportation pipeline.

Grace Point Participating Area

The Grace Point Participating Area contains 86 wells. The net average gas production for the three months ending December 31 2016, averaged approximately 933 gross Mcf/d of natural gas and 24,000 Bbls/d of water. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2016, estimated proved reserves for the wells in the Grace Point Participating Area were 1.8 gross (1.2 net) Bcf. We own an approximate 81% working interest in the wells drilled in the Grace Point Participating Area.

Doty Mountain Participating Area

The Doty Mountain *Participating* Area currently contains 107 wells. The net average gas production for the three months ending December 31 2016, averaged approximately 7,947 Mcf/d and 32,000 Bbls/d of water. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2016, estimated proved reserves for the wells in the Doty Mountain sub-area were 30.6 gross (19.9 net) Bcf. We currently own an approximate 79% working interest in the wells drilled in the Doty Mountain Participating Area.

Sun Dog Participating Area

As of December 31, 2016, the Sundog Participating Area contained 122 wells. The net average gas production for the three months ended December 31 2016, averaged approximately 1,896 Mcf/d and approximately 40,500 Bbls/d of water. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2016, estimated proved reserves for the wells in the Sun Dog sub-area were 12.9 Bcf gross (7.4 net) Bcf. We currently own a working interest of approximately 69% in the wells drilled in the Sun Dog Participating Area.

Catalina Unit

The Catalina Unit is operated by Escalera Resources, Inc., and consists of 71 wells. The net average gas production for the three months ended December 31 2016, averaged approximately 912 Mcf/d of natural gas. Warren currently owns a working interest of approximately 13.4% in the Participating Area "A" in the Catalina Unit. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2016, there were no estimated proved reserves for the wells in the Catalina unit.

Oil and Natural Gas Reserves

Third Party Reserve Reporting and Controls Over Reserve Report

The reserves estimates shown herein for the years ended December 31, 2016 and 2015, have been independently evaluated by Netherland, Sewell & Associates, Inc. ("NSAI"), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI's Letter is filed as an exhibit to this Form 10-K. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserve report incorporated herein are Mr. C. Ashley Smith and Mr. Shane M. Howell. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 2006. Mr. Smith is a Licensed Professional Engineer in the State of Texas (No. 100560) and has over 16 years of practical experience in petroleum engineering, with over 10 years of experience in the estimation and evaluation of reserves. Mr. Howell is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 11276) and has over 18 years of practical experience in petroleum geosciences, with over 11 years of experience in the estimation and evaluation of reserves. These NSAI reserve estimates are reviewed by our in-house petroleum engineers and geoscientists who oversee and control preparation of the reserve report data by working with NSAI to ensure the integrity, accuracy and timeliness of data furnished to NSAI for their evaluation process. Warren's technical person who was primarily responsible for overseeing the preparation of our reserve estimates was its Vice President of Operations. He has over 38 years of experience in the oil and gas industry, including 30 years as either a reserve evaluator or manager. His professional qualifications include a bachelor's degree in Petroleum Engineering from Texas A&M University and membership in the Society of Petroleum Engineers.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our 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 of engineering and geological interpretation and judgment. As a result, estimates of 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 either negatively or positively. 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 that we successfully develop our inventory of probable and possible locations, have positive revisions, acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by NSAI and other information about our oil and natural gas reserves, see Note L Oil and Gas Reserve Data (Unaudited) to the Consolidated Financial Statements in Item 8.

The current SEC rules require that the reserve estimates are based on the 12-month unweighted arithmetic average of the first-day-of- the-month price for each month in the period January through December 2016. For oil volumes, the average West Texas Intermediate posted price of $39.25 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.48 per MMbtu is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted product prices weighted by production over the remaining lives of the properties are $33.39 per barrel of oil and $1.59 per Mcf of gas. By area, these average adjusted prices are $33.39 per barrel of oil for the California business unit, $1.42 per Mcf of gas for the Pennsylvania business unit and $2.12 per Mcf of gas for the Wyoming business unit. All prices and costs associated with operating wells were held constant in accordance with the SEC guidelines.

The commodity price assumptions described above exceed the current market price of oil and gas. Therefore we may have a substantial downward adjustment in our estimated proved reserves in the future if the current low commodity price environment persists.

Estimated Proved Reserves

The following table presents our estimated proved natural gas and oil reserves and the PV-10 value of our interests in net reserves in producing properties as of December 31, 2016 and 2015 based upon reserve reports prepared by NSAI. The PV-10 values shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves we own.

	Successor	Predecessor
	Year ended December 31, 2016	Year ended December 31, 2015
Estimated Proved Oil and Natural Gas Reserves:		
Net oil reserves (MBbls):		
Proved developed	4,008	6,824
Proved undeveloped	724	6,115
Total	4,732	12,939
Net natural gas reserves (MMcf):		
Proved developed	114,719	153,093
Proved undeveloped	9,097	10,638
Total	123,816	163,731
Total Net Proved Oil and Natural Gas Reserves (MBoe)	25,368	40,227

	Successor Year ended December 31, 2016	Predecessor Year ended December 31, 2015
Estimated Present Value of Net Proved Reserves:		
PV-10 Value (in thousands)		
Proved developed	$ 21,497	$ 85,147
Proved undeveloped	6,858	10,876
Total(1)	28,355	96,023
Less: future income taxes, discounted at 10%	—	—
Standardized measure of discounted future net cash flows (in thousands)(2)	$ 28,355	$ 96,023
Prices Used in Calculating Reserves:		
Oil (per Bbl)	$ 33.39	$ 42.81
Natural Gas (per Mcf)	$ 1.59	$ 1.74
Proved Developed Reserves (MBoe)	23,127	32,339

(1) The PV-10 Value represents the future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10% per annum. Although it is a non-GAAP measure, we believe that the presentation of the PV-10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Our reconciliation of this non-GAAP financial measure is shown in the table as the PV-10, less future income taxes, discounted at 10% per annum, resulting in the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%. In accordance with SEC requirements, our reserves and the future net revenues at December 31, 2015 and 2016, were determined using average monthly pricing for 2015 and 2016. These prices reflect adjustment by lease for quality, transportation fees and regional price differences.

(2) Standardized measure of discounted future net cash flows may differ from PV-10 value because it includes the effect of future income taxes.

The data in the above natural gas and oil reserves table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered.

PV-10 is equal to the future net cash flows from our proved reserves, excluding any future income taxes, discounted at 10% per annum (“PV-10”). Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs for which the existence and recoverability of such reserves can be estimated with reasonable certainty or from existing wells on which a relatively major expenditure is required to establish production. PV-10 may be considered a non-GAAP financial measure as defined by Item 10(e) of Regulation S-K and is derived from the standardized measure of discounted future net cash flows which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV-10 is not a substitute for the standardized measure of discounted future net cash flows.

Oil and gas prices significantly impact the calculation of the PV-10 and the standardized measure of discounted future net cash flows. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company’s proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standard Board pronouncements, may not necessarily be the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

There are numerous uncertainties in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control. The reserve data set forth in this annual report on Form 10-K, are only estimates. Although we believe these estimates to be reasonable, reserve estimates are imprecise and may be expected to change as additional information becomes available. Estimates of natural gas and oil reserves, of necessity, are projections based on engineering data and there are uncertainties inherent in the interpretation of this data, as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be exactly measured. Therefore, estimates of the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, classifications of the reserves based on risk of recovery and the estimates are a function of the quality of available data and of engineering and geological interpretation and judgment and the future net cash flows expected there from, prepared by different engineers or by the same engineers at different times, may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves will be developed within the periods anticipated. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. In addition, the estimates of future net revenues from our proved reserves and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct.

With respect to the estimates prepared by NSAI, PV-10 value should not be construed as representative of the fair market value of our proved natural gas and oil properties since discounted future net cash flows are based upon projected cash flows which do not provide for changes in natural gas and oil prices or for the escalation of expenses and capital costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual future prices and costs may differ materially from those estimated. You are cautioned not to place undue reliance on the reserve data included in this annual report on Form 10-K. Under SEC guidelines, prices used in computing reserves at December 31, 2016 and 2015, are based on 12 month average pricing for 2016 and 2015, respectively.

Productive Wells

The following table sets forth our gross and net productive wells as of December 31, 2016 (Successor):

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
California	232	230	—	—	232	230
New Mexico	—	—	6	1.5	6	1.5
Pennsylvania	—	—	34	24.9	34	24.9
Texas	—	—	10	2.6	10	2.6
Wyoming	—	—	386	248.7	386	248.7
Total	232	230	436	277.7	668	507.7

Gross wells represent all wells in which we have a working interest. Net wells represent the total of our fractional undivided working interest in those wells. Productive wells include producing wells and wells mechanically capable of production. Not all wells listed above were on production as of December 31, 2016.

There were no development and exploration activities in progress at year end. Additionally, there were no proved undeveloped reserves with drilling activities in 2016.

Natural Gas and Oil Acreage

The following table sets forth our acreage position as of December 31, 2016 (Successor):

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	1,260	1,249	1,216	1,211	2,476	2,460
New Mexico	3,384	623	761	37	4,145	660
Pennsylvania	3,191	2,591	3,321	2,697	6,512	5,288
Texas	704	176	—	—	704	176
Wyoming	29,467	22,839	60,676	47,171	90,143	70,010
Other	440	138	1,280	1,280	1,720	1,418
Total	38,446	27,616	67,254	52,396	105,700	80,012

The primary terms of the Company's oil and gas leases expire on various dates in any given year. All of the Company's proved acreage is perpetuated by production, unitization or by continuous operations. This means that the Company will maintain its rights in these leases as long as natural gas or oil is produced in paying quantities or as long as operations are conducted on the acreage by the Company or other parties holding interests in those leases. In some cases, if production from a lease ceases, the lease will expire, and in other cases, if production or royalty payments attributable to any lease is interrupted or ceases, the Company may maintain the lease by unit production or conducting operations on the unit or lease.

The Company has approximately 427 and 28,781 and 2,344 net acres subject to leases with primary terms that expire in 2017, 2018 and 2019 respectively. Leases covering 534 net acres expired in 2016. The Company has in the past been and expects in the future to be able to extend the terms of some of these leases by conducting operations thereon or by exchanging or selling some of these leases to or with other companies. The Company does not expect to lose material developed lease acreage as a result of a failure to drill, inadequate capital, equipment, or personnel. The company did not meet the unit requirement to drill 25 gross CBM wells on or before September 11, 2016, and the Company has approximately 31,887 total net acres subject to contraction of the Spyglass Hill Unit. Many of those acres will expire in 2018, as reflected above, unless perpetuated by drilling operations.

Based on the Company's evaluation of prospective economics, the Company has allowed acreage to expire and will continue to allow additional acreage to expire in the future.

Production Volumes, Sales Prices and Production Costs

The following table summarizes our net natural gas and oil production volumes, our average sales prices and expenses for the periods indicated. Our production is attributable to our direct interests in producing properties. For these purposes, our net production will be production that is owned by us, after deducting royalty, limited partner and other similar interests. The lease operating expenses shown relates to our net production. In addition, this table summarizes our production for each field that contains 15% or more of our total proved reserves:

	Successor Year ended December 31, 2016	Predecessor Year ended December 31, 2015
Production:		
Oil (MBbls)		
Wilmington Field	793.8	980.3
Total	793.8	980.3
Natural Gas (MMcf)		
Wilmington Field	50.8	—
Marcellus	18,284.2	22,943.3
Atlantic Rim	4,291.5	4,709.8
Other	413.4	380.2
Total	23,039.9	28,033.3
Production:		
Total MBoe(1)	4,642.3	5,652.5
Average Sales Price Per Unit:		
Oil (per Bbl)	$ 34.09	$ 41.14
Natural gas (per Mcf)	$ 1.31	$ 1.55
Weighted average sales price (per Boe)	$ 12.35	$ 14.81
Expenses (per Boe):		
Lease operating expense(2)	$ 9.32	$ 8.76

(1) Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) Lease operating expenses related to our CBM operations include costs for operating our commercially productive CBM wells, together with the costs for operating our CBM wells that are still in the dewatering phase and are not yet commercially productive.

Crude Oil and Natural Gas Marketing

We sell our oil and natural gas production to various purchasers in the areas where the oil and natural gas is produced. Our revenues are highly dependent upon the prices of, and demand for, oil and gas. The markets for oil and gas have historically been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including location and quality differentials, seasonality, economic conditions, foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of OPEC, and domestic government regulation, legislation and policies. Decreases in oil and gas prices have had, and could have in the future, an adverse effect on the carrying value and volumes of our proved reserves and our revenues, profitability and cash flow.

We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. Derivatives provide us protection on the sales revenue streams if prices decline below the prices at which the derivatives are set. Our derivative instruments currently consist of swap agreements with financial institutions.

For 2016, the largest purchasers and marketers of our total oil and gas production were Phillips 66 Company, Clearwater Enterprises, and Devlar Energy, which accounted for 58%, 35% and 6%, respectively, of our total production sold.

All of our oil reserves are located in California and are sold into a transportation pipeline which delivers our oil production to Phillips 66 Company, which operates a refinery in nearby Carson, California. All of our oil production in California is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude oil differs from the established market indices in the U.S., due principally to the higher transportation and refining costs associated with heavy oil. Effective March 1, 2016, we entered into an oil purchase contract with Phillips 66 Company whereby the Company sells its oil at the average Midway Sunset posted price for the month less $3.05 per barrel plus a premium for a gravity adjustment which should approximate $0.20 per barrel. For 2016, Warren received a weighted average price of approximately 79% of the NYMEX index price for crude oil sold under the Phillips 66 contract.

Our natural gas production in Pennsylvania and Wyoming is delivered into natural gas pipelines for transportation and is sold to various purchasers for later re-marketing or end use. The majority of all of our natural gas is sold under monthly contracts that allow for periodic adjustments in pricing according to market demands. The prices and marketing of natural gas and oil can be affected by factors beyond our control, the effects of which cannot be predicted, including seasonal variations, general market supply and other fluctuations. In the Marcellus Shale, we sell our natural gas at the Tennessee Gas Pipeline (TGP, Zone 4) or the Transco-Leidy Line receipts market price less transportation fees. Both price points in the Marcellus and the CIG price typically have a negative basis differential below the NYMEX Henry Hub prompt month natural gas price. Fluctuations between spot and index prices can significantly impact the overall differential to the Henry Hub. In the Atlantic Rim of the Washakie Basin, Wyoming, we sell our natural gas at the Rocky Mountain Colorado Interstate Gas (“CIG”) market price less transportation fees. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as we believe there are a significant number of readily available purchasers in the market.

Hedging Activities

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price risk. We have an active commodity hedging program to mitigate the risks of the volatile prices of oil and natural gas. In accordance with our term loan, we intend to hedge approximately 75% of our oil and natural gas production on a forward 12 to 24 month basis using a combination of swaps, cashless collars and other financial derivative instruments with counterparties that we believe are creditworthy. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While there are many different types of derivatives available, we typically use collar agreements and swap agreements to attempt to manage price risk more effectively. The collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All collar agreements provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of oil, natural gas, and natural gas liquids for the period is greater or less than the fixed price established for that period when the swap is put in place. If the index price falls below the floor price, the counterparty pays us net of the fixed premium. If the index price rises above floor price, we pay the fixed premium. Our oil and gas hedges run into 2019.

Our Service and Operational Activities

Our drilling, completion, production, re-entry and land operations are conducted, managed and supervised for us through Warren E&P. Through Warren E&P, we employ petroleum engineers, geologists, drilling supervisors, landmen and field supervisors. Warren E&P also employs geologists, engineers and other personnel on a contract basis. As of December 31, 2016, Warren E&P was the operator of approximately 87% of the wells in which we had interests.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. In general, the bidding for natural gas and oil leases has become intense in the areas in which we operate with bidders evaluating potential acquisitions with varying product pricing parameters and other criteria that result in widely divergent bid prices. The presence of bidders willing to pay prices higher than are supported by our evaluation criteria could further limit our ability to acquire natural gas and oil leases. In addition, low or uncertain prices for properties can cause potential sellers to withhold or withdraw properties from the market. In this environment, we cannot guarantee that there will be a sufficient number of suitable natural gas and oil leases available for acquisition; that we can sell interests in natural gas and oil leases; or that we can obtain financing for, or locate participants to join in the development of prospects. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation that 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.

Regulations and Environmental Matters

General. Our operations are subject to a wide variety of stringent federal, state and local laws and regulations governing the exploration and production of oil and natural gas, including discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and gas exploration and production industry in the areas where we operate. These laws and regulations:

- require the acquisition of various permits before drilling, workovers, or water injection commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances, including without limitation;
- natural gas and water, that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wildernesses, wetlands and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closures and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations;
- require time consuming environmental analyses with respect to operations affecting federal, state and privately owned lands or leases; and
- expose us to litigation by environmental and other special interest groups.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. These regulations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages, and injunctive relief requiring us to cease production. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect. We believe that we substantially comply with all current applicable environmental laws and regulations, and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition or results of operations. However, we cannot predict the passage of or quantify the potential impact of more stringent future laws and regulations at this time. For the year ended December 31, 2016, we did not incur any material expenditures for remediation or pollution control equipment at any of our facilities.

The environmental laws and regulations which could have a material impact on the oil and natural gas exploration and production industry are as follows:

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an EA prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed EIS that may be made available for public review and comment. All of our current and proposed exploration, production and development plans on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Some of our exploration and production activities occur on federal leases. This is particularly true of our CBM operations. Exploration and production operations on federal leases are generally performed in accordance with a record of decision issued by the Bureau of Land Management ("BLM") after preparation of an EA or EIS. A record of decision typically includes environmental and land use provisions that restrict and limit exploration and production activities on federal leases. Much of our CBM operations are subject to records of decision, and we have not experienced any material difficulty in complying with their terms and conditions.

Waste Handling. The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes affect oil and gas exploration and production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of "hazardous wastes" and on the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil, natural gas or geothermal energy constitute "solid wastes", which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non- hazardous wastes as hazardous for future regulation. Legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes".

We believe we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent our operations require them under such laws and regulations. Although we believe the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs of managing and disposing of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund" law, imposes joint and several liabilities, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site, or site where the release occurred, and companies that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the 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 the hazardous substances released into the environment. Although petroleum is excluded from CERCLA's definition of "hazardous substance", in the course of our operations, we use materials that, if released, would be subject to CERCLA. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such "hazardous substances" have been deposited.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the applicable state agency. These restrictions also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. Response costs could be high and may have a material adverse effect on our operations. We may not be fully insured for these costs. We maintain all required discharge permits necessary to conduct our operations, and we believe we substantially comply with the terms thereof. Obtaining permits has the potential to delay the development of oil and natural gas projects. We anticipate that total maximum daily load water quality standards established under Clean Water Act delegated programs may be promulgated for surface water bodies in areas where we operate. However, we do not expect that any total maximum daily load regulations, or standards promulgated in any area where we operate, will result in a material increase in our produced water disposal costs because we already inject much of our produced water in disposal wells, rather than discharging into surface water bodies, and would be able to cost-effectively drill and operate additional disposal wells as needed.

Air Emissions. The Federal Clean Air Act and associated state laws and regulations regulate emissions of various air pollutants through the issuance of permits 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. Some of our new facilities will be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. Major sources of air pollutants are subject to more stringent, federally based permitting requirements. On April 17, 2012, the EPA issued a final rule that established new source performance standards for volatile organic compounds (“VOCs”) and sulfur dioxide, an air toxics standard for major sources of oil and natural gas production, and an air toxics standard for major sources of natural gas transmission and storage. These regulations apply to natural gas wells that are hydraulically fractured, or refractured, and to storage tanks and other equipment. Since January 1, 2015, all wells subject to the rule have been required to use “green completion” technology to limit emissions during well completion operations.

Because of the severity of ozone levels in portions of California, the state has the most severe restrictions on emissions of VOCs and nitrogen oxides (“NOX”) of any state. Producing wells, natural gas plants and electric generating facilities all generate VOCs and NOX. Some of our producing wells are in counties that are designated as non-attainment for ozone and, therefore, potentially are subject to restrictive emission limitations and permitting requirements. California also operates a stringent program to control hazardous (toxic) air pollutants, and this program could require the installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits generally are resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air-emission sources. Air emissions from oil and natural gas operations also are regulated by oil and natural gas permitting agencies, including in California, the South Coast Air Quality Management District, the California Air Resources Board and other local agencies. These regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations. We believe we are in substantial compliance with all air emissions regulations, and that we hold all necessary and valid construction and operating permits for our operations. Obtaining permits has the potential to delay the development of our oil and natural gas projects. See “Future Regulation—Wilmington Field” below.

The Safe Drinking Water Act, Groundwater Protection, and the Underground Injection Control Program. The Federal Safe Drinking Water Act (“SDWA”) and the Underground Injection Control (“UIC”) program promulgated under the SDWA and 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 saltwater 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.

We engage third parties to occasionally provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. With the exception of hydraulic fracturing using diesel fuel, the SDWA exempt hydraulic fracturing from regulation under the UIC program. On February 12, 2014, the EPA released an “interpretative memorandum” providing technical recommendations for implementing UIC requirements for hydraulic fracturing activities using diesel fuels. In this guidance document, EPA expansively defined the term “diesel” to include hydrocarbons such as kerosene that have not typically been considered to be diesel. Bills which would have repealed the hydraulic fracturing exemption have been introduced in the last three sessions of Congress. In addition, the EPA is conducting a congressionally-mandated study on the effects of hydraulic fracturing on drinking water resources. The EPA issued a final draft report in June 2015 for peer review and public comment. The EPA study, or other studies, of hydraulic fracturing could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory programs. In addition to federal regulation, certain states have adopted and are considering laws that require the disclosure of the chemical constituents in hydraulic fracturing fluids. Moreover, the Department of the Interior issued rules in March 2015 that modify regulations for hydraulic fracturing activities on federal and Indian lands, including chemical disclosure, well bore integrity and handling of flow back water. Additional disclosure and operational requirements could result in increased regulation, operational delays and increased operating costs that could make it more difficult to perform hydraulic fracturing.

California Environmental Quality Act ("CEQA"). CEQA is a California statute that requires consideration of the environmental impacts of proposed actions that may affect the environment. CEQA often requires the responsible governmental agency to prepare an environmental impact analysis document that is made available for public comment. In some cases, the responsible agency also is required to consider mitigation measures. The party requesting agency action bears the expense of the document.

In 2014, after a lengthy CEQA analysis, we received permit approvals from the South Coast Air Quality Management District ("SCAQMD") for the disposal of our WTU associated and produced gas. These permits allow us (i) to burn gas using a new high efficiency clean enclosed burner to replace the existing gas flare, and (ii) eventually, to sell the gas directly to a third party user by transporting the gas through transmission facilities owned by local gas utility companies. In the future, we may be required to undergo the CEQA process for other proposed actions by state and local governmental authorities that meet specified criteria. At a minimum, the CEQA process delays and adds expense to the process of obtaining new permits and permit renewals. See "Future Regulation—Wilmington Field" below.

Abandonment, Decommissioning and Remediation Requirements. Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production and transportation facilities, and the environmental restoration of operations sites. The California Department of Conservation, Division of Oil, Gas and Geothermal Resources ("DOGGR") is the principal state agency responsible for regulating the drilling, operation, maintenance and abandonment of all oil and natural gas wells in the state of California.

Significant potential costs relating to environmental and land-use regulations associated with our existing properties and operations include those relating to (i) plugging and abandonment of facilities, (ii) clean-up costs and damages due to spills or other releases, and (iii) penalties imposed for spills, releases or non-compliance with applicable laws and regulations. As is customary in the oil and natural gas industry, we typically have contractually assumed, and may assume in the future, certain obligations relating to plugging and abandonment, clean-up and other environmental costs in connection with our acquisition of operating interests in oil and gas fields, and these costs can be significant.

Climate Change Legislation and Greenhouse Gas Regulations. Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas ("GHG") emissions that have been or may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas 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 to these studies, many nations have agreed to limit emissions of GHG pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA*, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. On November 30, 2010, the EPA published a final rule that set forth reporting requirements for the petroleum and natural gas industry. This rule requires companies that hold state drilling permits and that emit 25,000 metric tons or more of carbon dioxide equivalent per year to report annual carbon dioxide, methane and nitrous oxide emissions from certain sources beginning on March 31, 2012. These reporting obligations continue in effect.

The EPA has also issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows the EPA to begin regulating emissions of GHGs under existing provisions of the Clean Air Act. The EPA has begun to implement GHG-related reporting and permitting rules for certain stationary sources. Beginning in 2012, the EPA has issued regulations aimed at reducing greenhouse gas emission, including methanol from oil and gas activities and recently announced plans to issue additional rules which target methane emissions from the oil and gas sector. The EPA's finding, the greenhouse gas reporting rules, and the rules to regulate the emissions of greenhouse gases may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry. Similarly, the U.S. Congress has considered, and may in the future consider, "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. Future federal climate change legislation could adversely impact our operations.

In addition to the EPA's actions to regulate GHGs, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas Initiative involving 10 Northeastern states and three Canadian provinces, the Western Climate Initiative involving California and four Canadian provinces, and the Midwestern Greenhouse Gas Reduction Accord involving seven states and one Canadian province. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which establishes a statewide cap on GHGs that will reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. The California Air Resources Board adopted regulations in December 2010 to implement AB 32 that commenced on January 1, 2012.

Our operations could be adversely impacted by current and future state and local climate change initiatives.

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

Hazard Communications and Community Right to Know

We are subject to federal and state hazard communications and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the 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 the public.

Operating Regulation of the Oil and Gas Industry

In addition to environmental laws and regulations, exploration, production and operations in the oil and gas industry are extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our drilling and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits and bonds for the drilling of wells and reports concerning operations. Most states and some counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production;
- underground injection of water and other substances;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units and govern the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. 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 requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. 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.

Natural Gas Sales Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale or resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted that have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales", which includes all of the sales of our production.

FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of the natural gas we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated. Therefore, we cannot guarantee that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future, nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering services, which occur upstream of jurisdictional transmission services, are regulated by state agencies. Although its policy is still in flux, FERC recently has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Permits. Our operations are subject to various federal, state and local laws and regulations that include requiring permits for the drilling and operation of wells, maintaining bonding and insurance requirements to drill, operate, plug and abandon wells, restoring the surface associated with our wells; and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells, the disposal of fluids and solids used in connection with our operations, and air emissions associated with our operations. Also, we have permits from numerous jurisdictions to operate crude oil, natural gas and related pipelines and equipment within the boundaries of these governmental jurisdictions. The permits required for various aspects of our operations are subject to enforcement for noncompliance, as well as revocation, modification and renewal by issuing authorities.

Operations on Federal Oil and Gas Leases

We conduct a sizeable portion of our operations on federal oil and natural gas leases which are administered by the BLM and the Minerals Management Service ("MMS"). Federal leases contain relatively standard terms and require compliance with detailed BLM and MMS regulations and orders, which are subject to change. Under certain circumstances, the BLM may require any of our operations on federal leases to be suspended, curtailed or terminated. Any such suspension or termination could have a material adverse effect on our business, financial condition and results of operations. The MMS issued a final rule that amended its regulations governing the valuation of oil and gas produced from federal leases. This rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil and gas produced from federal leases.

State Regulation

Our operations are also subject to regulation at the state, and in some cases, county, municipal and local governmental levels. Such regulation includes requirements concerning permits for the drilling of wells, maintaining bonding requirements in order 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, the plugging and abandonment of wells, and the disposal of fluids used and produced in connection with operations. Our operations are also subject to various conservation laws and regulations pertaining to the size of drilling, spacing and proration units and the unitization or pooling of oil and gas properties.

In California, as part of our waterflood development plan for the WTU and NWU, over the next 7 years, we will require 20 to 30 water injection well approvals from the California DOGGR. In recent years, the DOGGR has timely reviewed and approved our applications for injection permits. Should DOGGR delay the review process or deny our applications for future water injection wells, our ability to develop the WTU and NWU may be compromised.

The Wyoming Department of Environmental Quality, or Wyoming DEQ, has restrictive regulations applicable to the surface disposal of water produced from our CBM drilling operations. We typically are required to obtain Clean Water Act, Safe Drinking Water Act and analogous state and local permits to use surface discharge methods, such as settling ponds, to dispose of water when the groundwater produced from the coal seams will not exceed surface discharge permit limitations. Surface disposal options have volumetric limitations and require an extensive third-party water sampling and laboratory analysis program to ensure compliance with state permit standards. Alternative disposal methods to surface disposal of water are more expensive. These alternatives include installing and operating water treatment facilities or drilling disposal wells to inject the produced water in the underground formations below the coal seams or lower sandstone horizons. Injection wells are regulated by the Wyoming DEQ, the Wyoming Oil & Gas Conservation Commission and the BLM, and permits to drill these wells are obtained from these agencies. Based on our experience with CBM production, we believe that permits for surface discharge of produced water in the Washakie Basin have become and will continue to be difficult to obtain. As a result, in Wyoming, our produced water is currently re-injected into water disposal wells.

In the areas of Pennsylvania where we operate, water sourcing and wastewater disposal are regulated both by the Pennsylvania Department of Environmental Protection, or PADEP, as well as the Susquehanna River Basin Commission, or SRBC. The SRBC is a federal interstate watershed agency that oversees the withdrawal and use of surface water and groundwater from the Susquehanna River Basin for natural gas development and regulates interbasin transfers of produced fluids. The SRBC also restricts water withdrawal rates during periods of reduced precipitation to avoid adverse impacts to the water resources within the Susquehanna River Basin. The PADEP implements a statewide program governing all aspects of natural gas development. This program includes a requirement that operators submit a water management plan for DEP approval prior to the issuance of drilling permits. The PADEP imposes extensive operational and design standards on impoundments and pits that store freshwater or produced water associated with natural gas development. Discharges of produced water to streams in Pennsylvania are prohibited unless strict effluent limits are achieved. The EPA, rather than DEP administers the injection well program in Pennsylvania. Very few injection wells have been permitted in Pennsylvania to accept produced water from unconventional wells. In December of 2013, the PADEP proposed additional regulations governing the permitting and operation of natural gas wells. These regulations, if promulgated as proposed, are likely to increase significantly the costs to dispose of produced water, which could have a material adverse effect on our business, financial condition and results of operations.

In addition, state conservation laws, which frequently establish maximum rates of production from oil and gas wells, generally prohibit, restrict or regulate the venting or flaring of gas and impose certain requirements regarding the rates of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but, except as noted above, does not generally entail rate regulation. These regulatory burdens may affect our profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Future Regulations

Proposals and proceedings that may affect the oil and gas industry are pending before Congress, BLM, FERC, MMS, state legislatures and commissions, and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material adverse effect on our capital expenditures, earnings or competitive position.

Failure to comply with environmental regulations may result in the imposition of substantial administrative, civil or criminal penalties, or restrict or prohibit our desired business activities. Environmental laws and regulations impose liability, sometimes strict liability, for environmental cleanup costs and other damages. Other environmental laws and regulations may delay or prohibit exploration and production activities in environmentally sensitive areas or impose additional costs on these activities.

We believe we are in compliance with current applicable environmental laws and regulations. We believe the existence and enforcement of such laws and regulations have no more restrictive an effect on our operations than on other similar companies in the energy industry. Costs associated with responding to a major spill of crude oil or produced water, or costs associated with remediation of environmental contamination, are the most likely occurrences that could result in a material adverse effect on our business, financial condition and results of operations. There are no pending or threatened claims for any such environmental cleanup costs, and we operate our producing properties in a prudent manner in order to avoid or minimize liability related to any such claims.

Changes in applicable federal, state and local environmental laws and regulations potentially could have a material adverse effect on our business, financial condition and results of operations. In this regard, our CBM drilling and production operations are subject to ongoing BLM oversight, EIS requirements and recurring BLM approvals, and could be affected by changes in BLM regulations or policies.

We anticipate no material capital expenditures to comply with federal and state environmental requirements. In addition, state-wide reclamation bonds and our $50 million casualty and environmental insurance policy have been adequate to meet the applicable bonding and insurance requirements to date. Additionally, we have deposited $2.9 million in money market securities as of December 31, 2016, as collateral for a $3.2 million reclamation bond for the Wilmington Townlot Unit.

Coalbed Methane Operations. The majority of our gas production is from CBM operations that generate water discharges and air emissions that are subject to significant regulatory control. Naturally occurring groundwater is produced by our CBM operations. This produced water is disposed of by injection into the subsurface through disposal or water injection wells, and, in some cases, discharge to the surface or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by state and federal regulatory agencies, and in compliance with applicable state, federal and local environmental regulations. To date, we have been able to obtain necessary surface discharge or disposal well permits, and we have been able to discharge produced water and operate our produced water disposal wells in compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities.

Our CBM operations involve the use of gas-fired generators and compressors to transport the gas we produce. Emissions of nitrogen oxides and other combustion by-products from individual or multiple generators and compressors at one location may be great enough to subject the compressors to state air quality requirements for pre-construction and operating permits. To date, we have not experienced significant delays or problems in obtaining the required air permits and have been able to operate these compressors in compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities. Another air emission associated with our coalbed methane operations that may be subject to regulation and permitting requirements is particulate matter resulting from construction activities and vehicle traffic.

Atlantic Rim. In May 2007, the BLM issued its Record of Decision for the Atlantic Rim EIS that allows the development of the Atlantic Rim project by drilling up to 2,000 wells, 1,800 of which are CBM wells and 200 of which are deeper conventional wells. Based on the current knowledge of geologic formations, the BLM’s minimum well spacing will be 80 acres per CBM well. Our Washakie Basin CBM production operations are also subject to Wyoming Department of Environmental Quality, or DEQ, regulations and permit requirements. Permits required from the Wyoming DEQ include air emission and produced water discharge permits. To date, we have not experienced any difficulties in obtaining any air permits needed for our Washakie Basin operations from the Wyoming DEQ. Disposal of produced water is limited to subsurface injection in the portion of the Washakie Basin within the Colorado River drainage area. We have received permits for a sufficient number of water injection wells in the Atlantic Rim project; however, we will need to obtain permits for additional injection wells, in the event we need additional subsurface disposal capacity.

Wilmington Field. The Wilmington Townlot Unit, or WTU, and the North Wilmington Unit, or NWU, are located in a mixed industrial and residential area near the Port of Los Angeles, California. Field activities include drilling wells to develop our lease acreage and operating a waterflood to maximize crude oil production. Stringent environmental regulations, restrictive permit conditions and the possibility of permit denials from a multiplicity of state, regional and local regulatory agencies may inhibit, curtail or add cost to future Wilmington field development activities. Despite prudent operation and preventative measures, drilling, waterflooding and production operations may result in spills and other accidental releases of produced water, hydrocarbons or injection fluids. Remediation and associated costs for a release of produced water, hydrocarbons or injection fluids in an urban environment could be significant. This potential liability is accentuated by the location of our WTU and NWU leases in or near residential areas, and being within a historically active oil field.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, spills or releases of crude oil, produced water and injection fluids, and other potential events which could have a material adverse effect on our business, financial condition and results of operations. Any of these problems could adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, production or leasehold acquisitions, or result in the loss of certain properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. For some risks, we may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs and is not fully covered by insurance, it could have a material adverse effect on our business, financial condition and results of operations.

Title to Properties

In most situations, as is customary in the oil and gas industry, only a preliminary title examination is conducted at the time we acquire oil and gas leases covering properties for possible drilling operations. Prior to the commencement of drilling operations, a more complete title examination of the drill site tract is usually conducted by independent attorneys or landmen, or in the case of an existing unit, historical title examinations are relied upon to some extent. Once production from a given well is established, we prepare a title or division of interest report indicating the proper parties and percentages for payment of production proceeds, including royalties. The level of title examination often differs from property to property.

Our properties are subject to customary royalty interests, provisions, liens incident to operating agreements, liens for current taxes and other burdens which, on an individual lease basis, we believe do not materially interfere with the use of or affect the carrying value of our properties.

Employees

At December 31, 2016, we had 66 full-time employees. We believe that our relationships with our employees are good. None of our employees are covered by a collective bargaining agreement. From time to time, we use the services of independent consultants to perform various professional services, particularly in the areas of geological, permitting and EA activities. Independent contractors often perform well drilling and production operations, including pumping, maintenance, dispatching, inspection and testing.

Offices

Our principal executive office is located at Two Lincoln Centre, 5420 LBJ Freeway, Suite 600, Dallas, TX 75240, and our telephone number is (214) 393-9688. We lease approximately 11,832 square feet of office space for our Dallas, TX office under a lease that expires in April 2022. Our oil and gas operations office in Casper, Wyoming occupies 1,174 square feet under a lease that expired in October 2014 and is currently month to month. Our oil and gas operations office in Long Beach, California occupies 3,326 square feet of space under a lease that expires in November 2018. We lease additional space for our other office located in Denver, CO which occupies 4,507 square feet and is currently month to month. We also have field offices in Tunkhannock, Pennsylvania, Wilmington, California and Rawlins, Wyoming. We believe that our facilities are adequate for our current operations.

Our website address is http://www.warrenresources.com. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC at http://www.sec.gov. Additionally, our Code of Business Conduct and Ethics, which includes our code of ethics for senior financial management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are posted on our website and are available in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our principal office at Two Lincoln Centre, 5420 LBJ Freeway, Suite 600, Dallas, TX 75240. Information contained on, or connected to, our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. Risk Factors

We are a smaller reporting company as defined in Rule 12b-2 of the Exchange Act; therefore, pursuant to Regulation S-K, we are not required to make disclosures under this Item.

Item 1B: Unresolved Staff Comments.

None.

Item 2: Properties

A description of our properties is included in Items 1 and 2. Business and Properties above and is incorporated herein by reference.

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

Item 3: Legal Proceedings

Emergence from Voluntary Reorganization under Chapter 11

On June 2, 2016, the Company and certain of its wholly owned subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Case No. 16-32760. The Debtors continued to operate their businesses as “debtors-in-possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The subsidiary Debtors in the Chapter 11 Cases were Warren E&P, Warren California, Warren Marcellus, Warren Energy Services, LLC and Warren Management Corp., which represent all subsidiaries of the Company. On September 14, 2016, the Bankruptcy Court entered an order approving the Plan of Reorganization of Warren Resources, Inc. and Its Affiliated Debtors On October 5, 2016, the Plan became effective pursuant to its terms, and the Debtors completed their reorganization under the Bankruptcy Code.

The description of the Plan can be found in its entirety by reference to the full text of the Confirmation Order, filed as Exhibit 2.1 to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission (the “SEC”) on September 20, 2016.

Litigation in the Normal Course of Business

We are party to a variety of legal, administrative, regulatory and government proceedings, claims and inquiries arising in the normal course of business. While the results of these proceedings, claims and inquiries cannot be predicted with certainty, management believes that the ultimate outcome of such matters will not have a material effect on the Company’s financial condition or results of operations.

Item 4: Mine Safety Disclosures

Not applicable.

PART II

Item 5: Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information.

There is no established public trading market for our common stock. Therefore, there is a risk that a stockholder may not be able to sell our stock at a time or price acceptable to the stockholder. Unless and until shares of our common stock are listed on a national securities exchange, it is not expected that a public market for shares of our common stock will develop.

Holders

As of March 31, 2017 there were approximately 70 record holders of our common stock.

Dividend Policy

We have never paid or declared any cash dividends on our common stock. Dividends are also restricted under the terms of Exit Credit Facility. We currently intend to retain earnings, if any, to service our debt obligations and finance the growth and development of our business and we do not expect to pay any cash dividends on our common stock in the foreseeable future.

Recent Sales of Unregistered Securities

None.

Securities Authorized for Issuance Under Compensation Plans

None.

The table below includes information about our equity compensation plans as of December 31, 2016, each of which has been approved by our stockholders:

	Number of Shares Authorized for Issuance under plan	Number of securities to be issued upon exercise of outstanding options and restricted stock	Weighted-average exercise price of outstanding options and restricted stock	Number of securities remaining available for future issuance under equity compensation plans
2016 Equity Incentive Plan	600,000	0	$ N/A	600,000

Item 6: Selected Financial Data

We are a smaller reporting company as defined in Rule 12b-2 of the Exchange Act; therefore, pursuant to Regulation S-K, we are not required to make disclosures under this Item.

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

The discussion and analysis that follows should be read together with the "Selected Consolidated Financial Data" and the accompanying financial statements and notes related thereto that are included elsewhere in this annual report on Form 10-K. It includes forward-looking statements that may reflect our estimates, beliefs, plans and expected performance. The forward-looking statements are based upon events, risks and uncertainties that may be outside our control. Our actual results could differ significantly from those discussed in these forward-looking statements. Factors that could cause or contribute to these differences include but are not limited to, market prices for natural gas and oil, regulatory changes, estimates of proved reserves, economic conditions, competitive conditions, development success rates, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this annual report on Form 10-K, including in "Cautionary Note Regarding Forward-Looking Statements", all of which are difficult to predict. As a result of these assumptions, risks and uncertainties, the forward-looking matters discussed may not occur.

Overview

We are an independent energy company engaged in the exploration and development of domestic onshore oil and natural gas reserves. We focus our efforts primarily on the development of our waterflood oil recovery properties in the Wilmington field within the Los Angeles Basin of California, the Marcellus Shale in northeastern Pennsylvania and our coalbed methane, or CBM, natural gas properties located in the Wyoming region.

As of December 31, 2016, we owned natural gas and oil leasehold interests in approximately 105,897 gross (80,099 net) acres, approximately 66% of which were undeveloped. Substantially all our undeveloped acreage is located in Wyoming. Our total estimated net proved reserves are located on approximately 30% of our net acreage.

Liquidity and Capital Resources

Our cash and cash equivalents decreased approximately $21.1 million in 2016 to $5.6 million compared to 2015. This resulted from cash used in operating activities of $25.5 million and cash used in investing activities of $3.9 million which was offset by cash provided by financing activities of $10.0 million.

Capital expenditures for 2016 amounted to $5.1 million which represents an 86% reduction in spending from the 2015 level. This drastic reduction reflects the severe cash limitations imposed on the Company in 2016.

Our primary sources of pre-petition liquidity through the first half of the calendar year was cash provided by operations. The Company also had access to a post-petition $20 million DIP Credit Facility during the pendency of the Chapter 11 Cases (as defined below). This was never utilized, as operating cash flow was sufficient to meet post-filing obligations.

Upon emergence from the Chapter 11 Cases (as defined below),bankruptcy, Warren was provided with a $150 million term loan, of which $130 million was immediately deemed outstanding as the initial debt under the terms of the restructuring, and $20 million of "new credit" available on a delayed draw basis. Warren borrowed $10 million of this amount during the fourth quarter of 2016 and the balance remained undrawn at year-end. See the section below for an expanded description of this facility. The full description of this term loan is below in the section titled "Successor Exit Credit Facility."

Reorganization

On June 2, 2016, the Company and certain of its wholly owned subsidiaries (together with the Company, the "Debtors") filed voluntary petitions (the "Bankruptcy Petitions") for reorganization (the "Chapter 11 Cases") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"), Case No. 16-32760. The Debtors continued to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The subsidiary Debtors in the Chapter 11 Cases were Warren E&P, Inc, Warren Resources of California, Inc., Warren Marcellus, LLC, Warren Energy Services, LLC and Warren Management Corp., which represent all subsidiaries of the Company. On September 14, 2016, the Bankruptcy Court entered an order (the "Confirmation Order") approving the Plan of Reorganization of Warren Resources, Inc. and Its Affiliated Debtors (as amended and supplemented, the "Plan"). On October 5, 2016 (the "Effective Date"), the Plan became effective pursuant to its terms, and the Debtors completed their reorganization under the Bankruptcy Code.

Fresh-start Accounting

Upon the Company's emergence from chapter 11 bankruptcy, the Company qualified for and adopted fresh-start accounting in accordance with the provisions set forth in ASC 852 as (i) the Reorganization Value of the Company's assets immediately prior to the date of confirmation was less than post-petition liabilities and allowed claims, and (ii) the holders of the existing voting shares of the Predecessor entity received less than 50% of the voting shares of the merging entity. Fresh-start accounting required the Company to present its assets, liabilities, and equity as if it were a new entity upon emergence from bankruptcy. The new entity is referred to as "Successor" or "Successor Company." However, the Company will continue to present financial information for any periods before adoption of fresh-start accounting for the Predecessor Company. The Predecessor and Successor companies may lack comparability and therefore, "black-line" financial statements are presented to distinguish between the Predecessor and Successor Companies.

Adopting fresh-start accounting results in a new financial reporting entity with no beginning retained earnings or deficit as of the fresh-start reporting date. Upon the application of fresh-start accounting, the Company allocated the Reorganization Value (the fair value of the Successor Company's total assets) to its individual assets based on their estimated fair values. The Reorganization Value is intended to represent the approximate amount a willing buyer would value the Company's assets immediately after the reorganization.

Successor Exit Credit Facility

On the Effective Date, pursuant to the Plan, the Company entered into a Credit Agreement by and among the Company, Wilmington Trust, National Association, as Administrative Agent (the "Agent"), and the lenders from time to time party thereto (the "Credit Agreement"). The Credit Agreement provides for a $150 million term loan facility (the "Exit Credit Facility"), consisting of initial senior secured term loans in an aggregate principal amount of $130 million (which, pursuant to the Plan, is deemed to be outstanding without any advancement of funds by the lenders under the Credit Agreement) and additional senior secured term loans (the "delayed draw term loans") in an aggregate principal amount of up to $20 million, which, subject to the conditions set forth in the Credit Agreement, may be drawn from time to time by the Company.

The outstanding term loans, along with accrued and unpaid obligations with respect to such loans, under the Exit Credit Facility are subject to prepayment in respect of (i) proceeds from the issuance or incurrence of debt, excluding those items of debt permitted to be issued or incurred under the Credit Agreement and (ii) casualty proceeds and proceeds received from asset dispositions, subject to limited reinvestment rights and certain excluded asset sales. The Exit Credit Facility is guaranteed by all of the Company's wholly owned subsidiaries. The Exit Credit Facility is secured by substantially all of the oil and gas assets of the Company and the Guarantors, as well as all of the equity interests in the Guarantors. Certain third-party swap and derivative transactions may be secured pursuant to an intercreditor agreement on a *pari passu* basis with the same collateral securing the Exit Credit Facility. The Exit Credit Facility also includes certain covenants, including a net debt to EBITDA ratio as defined in the credit agreement.

Proceeds of the delayed draw term loans under the Exit Credit Facility may be used from time to time for lawful corporate purposes, including for working capital needs and to finance corporate and capital expenditures and permitted acquisitions of oil and gas properties and other assets related to the exploration, production, development, processing, gathering, storage and transportation of hydrocarbons.

The interest rate on borrowings under the Exit Credit Facility will be equal to the sum of (i) the LIBOR rate (with a minimum LIBOR rate of 1%) plus 9.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid in cash, plus (ii) an amount equal to 1.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid-in-kind and added to the outstanding principal amount of the loans on each quarterly interest payment date. Other than with respect to prepayments or during periods in which the outstanding principal amount of the loans and other obligations under the Exit Credit Facility is subject to an increased interest rate following the occurrence of an event of default under the Credit Agreement, interest on each loan under the Exit Credit Facility shall be due and payable on the next to last business day of each March, June, September and December and on May 22, 2020, the maturity date under the Credit Agreement (the "Maturity Date").

The outstanding balance of the Exit Credit Facility at December 31, 2016 amounted to $140.3 million which includes $0.3 million of paid-in-kind interest.

During 2016, the Company reported a net loss of $317.6 million (which included $232.2 million of impairment expense and $35.5 million of interest expense). This compares to 2015 when the Company had a net loss of $620.0 million (which included $578.3 million of impairment expense and $30.4 million of interest expense).

On December 31, 2016, our total proved reserves were 25.4 MMBoe. Revisions decreased 2016 proved natural gas reserves and oil reserves by a net amount of 16.9 Bcf and 7.4 MMbbls as described below:

Wyoming – Lower gas prices coupled with increased marketing differentials resulted in a 53% drop in total proved reserves, comprised of a 10% decrease in proved developed producing reserves, 20% in proved developed non-producing and a 100% drop in the proved undeveloped category. The total value of the proved reserves (PV10%) decreased by $7.4 million from $15.4 million to $8.0 million.

Pennsylvania – Although the gas pricing used to generate the 2016 reserves was lower than 2015 pricing, marketing differentials decreased significantly resulting in a 17% increase in total proved reserves compared with 2015, virtually all realized in the proved developed producing category. The total value of the proved reserves (PV10%) increase by $12.6 million from a negative $5.6 million to $7.0 million.

California – A significant drop in SEC oil prices resulted in a decrease of 58% to the total proved reserves. This decrease was comprised of a 33% decrease in proved developed producing reserves, a 25% decrease in proved developed non-producing reserves and an 88% decrease in proved undeveloped reserves. A significant portion of the reduction in proved undeveloped reserves is attributable to the SEC "5 year rule"; these reserves will be returned to the reserve report in the following year, subject to pricing. The total value of the proved reserves (PV10%) decreased by $73.0 million from $85.9 million to $12.9 million, mainly due to pricing and the SEC "5 year rule".

The Company's proved reserves decreased as of December 31, 2015 compared to prior years. The 2015 decrease was primarily the result of the sustained low commodity price environment. Our oil operations include a secondary recovery waterflood with significant fixed costs. During 2015, our oil lease operating expenses were $21.83 per barrel of oil produced. Our natural gas operations include reinjecting the produced water into deep formations and compressing and transporting the gas with significant fixed costs. During 2015, our natural gas lease operating expenses were $1.00 per Mcf of gas produced. The Company's estimated proved reserves are based on assumptions that may prove to be inaccurate. The Company's estimated proved reserves for the periods indicated are listed below.

	Successor Year Ended December 31, 2016	Predecessor Year Ended December 31, 2015
Estimated Proved Oil and Natural Gas Reserves:		
Net oil reserves (MBbls)	4,732	12,939
Net natural gas reserves (MMcf)	123,816	163,731
Total Net Proved Oil and Natural Gas Reserves (MBoe)	25,368	40,227
Estimated Present Value of Net Proved Reserves (in thousands):		
PV-10 Value		
Proved developed	$ 21,497	$ 85,147
Proved undeveloped	6,858	10,876
Total	28,355	96,023
Less: future income taxes, discounted at 10%	—	—
Standardized measure of discounted future net cash flows	$ 28,355	$ 96,023
Prices Used in Calculating Reserves:		
Oil (per Bbl)	$ 33.39	$ 42.81
Natural Gas (per Mcf)	$ 1.59	$ 1.74
Proved Developed Reserves (MBoe)	23,127	32,339

2016 and 2017 Capital Expenditure Program

During 2016, we invested $5.0 million in our capital expenditure program. This was substantially below the $36.1 million spent during the course of 2015 and reflected the Company's objective to conserve cash. The majority of this investment consisted of infrastructure expenditures in California and other projects designed to sustain production levels as much as possible during the restructuring period.

The Company forecasts a 2017 capital expenditure budget of $8.5 million. Given the continued downward pressure on hydrocarbon prices, most of this commitment will be dedicated to returning existing wells to production and, to a limited degree, development opportunities in our Marcellus Shale field. The Company intends to fund 2017 capital expenditures with cash flows from operations. Of course, we will continue to look for strategic acquisition opportunities in the normal course, but have not designated any of our projected spending to that end.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Below, we provide expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Notes to the Consolidated Financial Statements for a discussion of additional accounting policies and estimates made by management.

Oil and Gas Producing Activities

We account for our oil and gas activities using the full cost method. As prescribed by full cost accounting rules, all costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of oil and gas properties as well as other internal costs that can be specifically identified with acquisition, exploration and development activities are also capitalized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs are depleted on the equivalent unit-of-production method, based on proved oil and gas reserves as determined by independent petroleum engineers.

In accordance with full cost accounting rules, Warren is subject to a limitation on capitalized costs. The capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10 percent, plus the cost of unproved properties excluded from amortization, as adjusted for related tax effects. If capitalized costs exceed this limit (the “ceiling limitation”), the excess must be charged to expense. In 2016, we recorded an impairment charge of $232.2 million. In 2015 we recorded an impairment charge of $578.3 million.

The costs of certain unevaluated oil and gas properties and exploratory wells being drilled are not included in the costs subject to amortization. Warren assesses costs not being amortized for possible impairments or reductions in value and if impairments or a reduction in value has occurred, the portion of the carrying cost in excess of the current value is transferred to costs subject to amortization.

Our estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows are derived from these reserve estimates, in accordance with SEC guidelines by an independent engineering firm based in part on data provided by us. The accuracy of our reserve estimates depends in part on the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Revenue Recognition

Oil and gas sales result from undivided interests held by us in various oil and gas properties. Sales of natural gas and oil produced are recognized when delivered to or picked up by the purchaser. Warren accrues for revenue based on estimated pricing and production.

Results of Operations

Three Months Ended December 31, 2016 and Nine Months Ended September 30, 2016 Compared to the Year Ended December 31, 2015

Revenues

Oil and Gas Revenues

Revenue from oil and gas sales were $16.9 million and $39.7 million for the three months ended December 31, 2016 (Successor) and the nine months ended September 30, 2016 (Predecessor), respectively. This represents a year over year decrease of $27.1 million or 32% when compared to oil and gas sales of $83.7 million for the year ended December 31, 2015 (Predecessor). This decrease results from a 19% reduction in production from both oil and gas as well as a 17% reduction in realized price. The average realized price of oil on a year over year basis dropped from $41.14/bbl in 2015 to $34.09/bbl in 2016. Additionally the average realized gas prices dropped from $1.55/mcf in 2015 to $1.30 in 2016.

Transportation Revenue

We receive fees for transporting gas through our Atlantic Rim intrastate pipeline, which connects with the Wyoming Interstate Company (WIC) System. Transportation revenue totaled $1.0 million for the three months ended December 31, 2016 (Successor) and $3.2 million for the nine months ended September 30, 2016 (Predecessor). This represents a year over year decrease of 10% when compared to transportation revenue of $4.6 million for the year ended December 31, 2016 (Predecessor).

Operating Expenses

Lease operating expenses and taxes

Lease operating expense amounted to $10.7 million for the three months ended December 31, 2016 (Successor) and $32.6 million for the nine months ended September 30, 2016 (Predecessor). This represents a year over year reduction of $6.3 million or 13% when compared to lease operating expense of $49.6 million for the year ended December 31, 2015 (Predecessor). This decrease results from cost savings efforts instituted to control operating expenses.

Depreciation, depletion and accretion (DD&A)

DD&A totaled $10.8 million for the three months ended December 31, 2016 (Successor) and $18.9 million for the nine months ended September 30, 2016 (Predecessor). This represents a year over year reduction of $36.5 million when compared to DD&A of $66.2 million for the year ended December 31, 2015 (Predecessor). DD&A for the three months ended December 31, 2016 (Successor) reflects the impact of restating the Company's oil and gas properties at fair value under fresh-start accounting. DD&A for 2016 was also significantly less than 2015 reflecting the impact of large impairments for the nine months ended September 30, 2016 (Predecessor) and for the year ended December 31, 2015 (Predecessor). In 2017, DD&A will continue to decrease in comparison to 2016 given the effects of the impairment charge recognized as of December 31, 2016.

Impairment expense

The Company recorded impairment expense of $145.1 million for the three months ended December 31, 2016 (Successor). This impairment reflects the pricing differences between the first-day-of-the-month average price for the preceding twelve months required by Regulation S-X, Rule 4-10 and ASC 932 used in calculating the ceiling test and the forward-looking prices used by ASC 852 to estimate the fair value of the Company's oil and gas properties on the fresh-start reporting date, September 30, 2016. The Company recorded ceiling test impairments totaling $87.1 million for the nine months ended September 30, 2016 (Predecessor). These impairments were driven by decreases in commodity prices used in the ceiling test calculation since December 31, 2015. We recorded ceiling test impairments totaling $578.3 million for the year ended December 31, 2015 (Predecessor). The impairments in 2015 were driven by decreases in commodity prices used in the ceiling test calculation since December 31, 2014.

Transportation expense

Pipeline operating expenses totaled $0.5 million for the three months ended December 31, 2016 (Successor) and $1.0 million for the nine months ended September 30, 2016 (Predecessor). This represents a year over year reduction $0.2 million when compared to transportation expense for the year ended December 31, 2015 (Predecessor).

General and administrative expense (G&A expense)

G&A expense was $3.3 million for the three months ended December 31, 2016 (Successor) and $8.9 million for the nine months ended September 30, 2016 (Predecessor). This represents a $5.5 million or 31% reduction in G&A expense of $17.7 million for the year ended December 31, 2015 (Predecessor). This reduction reflects management's cost savings efforts to control G&A expense.

Reorganization items

The Company incurred restructuring expenses of $14.2 million for the nine months ended September 30, 2016 (Predecessor). These amounts consist of legal and professional fees associated with the Chapter 11 Cases.

Other Income (Expense)

Interest and other income

Interest and other income amounted to $0.1 million for the three months ended December 31, 2016 (Successor) and $0.5 million for the nine months ended September 30, 2016 (Predecessor). However, interest and other income amounted to $5.6 million for the year ended December 31, 2015 (Predecessor). The 2015 amount primarily pertains to the sale of non-oil and gas property in our North Wilmington Unit in California.

Interest expense

Interest expense totaled $3.6 million for the three months ended December 31, 2016 (Successor). This level of interest expense reflects the discontinuance of interest expense on our Predecessor borrowings that were cancelled as part of our Chapter 11 Cases. However, it does include interest expense on our Exit Credit Facility for the three month period.

Interest expense amounted to $31.8 million for the nine months ended September 30, 2016 (Predecessor) which includes interest expense on our First Lien Credit Facility, Second Lien Credit Facility and Senior Notes.

Interest expense amounted to $30.4 million for the year ended December 31, 2015 (Predecessor). This excludes $8.8 million of capitalized interest associated with the development of the Marcellus Assets.

Gain (Loss) on financial instruments

The Company recorded a loss on derivative financial instruments of $10.9 million during the three months ended December 31, 2016 (Successor). This consisted of an unrealized loss on the change in mark-to-market valuations of $10.2 million and a realized loss on cash settlements of $0.7 million.

The Company recorded a gain on derivative financial instruments of $0.8 million during the nine months ended September 30, 2016 (Predecessor). This consisted of an unrealized loss on the change in mark-to-market valuations of $10.9 million and a realized gain on cash settlements of $11.7 million.

The Company recorded a gain on derivative financial instruments of $20.1 million for the year ended December 31, 2015 (Predecessor). This consisted of an unrealized gain on the change in mark-to-market valuations of $13.0 million and a realized gain on cash settlements of $7.1 million.

Loss on contingent consideration

The Company recorded a loss of $0.4 million from the contingent consideration related to the acquisition of our Marcellus Assets for the nine months ended September 30, 2016 (Predecessor). Additionally, a loss of $0.5 million was incurred for the year ended December 31, 2015 (Predecessor). This amount reflects the fair value adjustment for the contingent consideration payment as part of the purchase and sale with Citrus.

Gain on debt extinguishment

A $14.4 million gain from the retirement of debt related to the exchange of previously issued Senior Notes for term notes under the First Lien Credit Facility was recorded for the year end December 31, 2015 (Predecessor).

Troubled debt restructuring expense

Troubled debt restructuring expense of $4.0 million was recognized during the year ended December 31, 2015 (Predecessor). This resulted from the exchange of previously issued Senior Notes for term notes under the Second Lien Credit Facility. This transaction was accounted for as a troubled debt restricting in accordance with ASC 470.

Contractual Obligations

Leases

The Company leases corporate office space in Denver, Colorado on a month to month status. The Company leases oil and gas administrative offices located in Dallas, Texas which expires in April, 2022. The Company leases field office space in Rawlins, Wyoming which is on a month to month status. The Company leases office space in Long Beach, California which expires in November 2018. The Company leases office space in Tunkhannock, Pennsylvania which expires in August 2019. The Company leases office space in Casper, Wyoming on a month to month status.

Transportation Fee

Contracts assumed related to the Marcellus assets stipulated that the Company pay a fixed monthly amount of $1,241,000 for transportation of gas through the interstate pipeline, up to 120,000 dekatherms per day for a term ending in July 2022 (67 months remain on the contract). If the Company exceeds 120,000 dekatherms per day, the agreement states that a monthly fee of $0.34 per dekatherm over the contractually stipulated amount should be paid. Following the emergence from bankruptcy in October 2016, the commitment was reduced to 90,000 dekatherms per day for the next 36 months of the contract. Warren accounts for the aforementioned gathering and transportation fees on the Consolidated Statements of Operations within the lease operating expenses and taxes line item, as incurred. No overage fees have been included in the calculation of transportation fees.

Long-term debt and interest obligations

On the Effective Date, pursuant to the Plan, the Company entered into a Credit Agreement by and among the Company, Wilmington Trust, National Association, as Administrative Agent (the "Agent"), and the lenders from time to time party thereto (the "Credit Agreement"). The Credit Agreement provides for a $150 million term loan facility (the "Exit Credit Facility"), consisting of initial senior secured term loans in an aggregate principal amount of $130 million (which, pursuant to the Plan, is deemed to be outstanding without any advancement of funds by the lenders under the Credit Agreement) and additional senior secured term loans (the "delayed draw term loans") in an aggregate principal amount of up to $20 million, which, subject to the conditions set forth in the Credit Agreement, may be drawn from time to time by the Company. The outstanding balance of the Exit Credit Facility at December 31, 2016 amounted to $140.3 million which includes $0.3 million of paid-in-kind interest. The maturity date under the Credit Agreement (the "Maturity Date") is May 22, 2020.

The interest rate on borrowings under the Exit Credit Facility will be equal to the sum of (i) the LIBOR rate (with a minimum LIBOR rate of 1%) plus 9.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid in cash, plus (ii) an amount equal to 1.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid-in-kind and added to the outstanding principal amount of the loans on each quarterly interest payment date. Other than with respect to prepayments or during periods in which the outstanding principal amount of the loans and other obligations under the Exit Credit Facility is subject to an increased interest rate following the occurrence of an event of default under the Credit Agreement, interest on each loan under the Exit Credit Facility shall be due and payable on the next to last business day of each March, June, September and December and on May 22, 2020, the Maturity Date under the Credit Agreement.

Asset Retirement Obligations

Our obligations result from the acquisition, construction or development and the normal operation of out long-lived assets. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. At December 31, 2016, a liability of $34.9 million was recorded as a long-term liability in the consolidated financial statements.

Bankruptcy Claims

Associated with the Company's filing and emergence from the Chapter 11 Cases, creditors have filed claims against the Company. The claims reconciliation process is ongoing and the estimated liability has not been finalized. The process includes review of the underlying claim filed against the Company and a reconciliation against the debtor's books and records.

The Company has estimated the liabilities associated with these claims at $1.5 million. This liability is included as a current liability in the consolidated financial statements at December 31, 2016.

Recent Accounting Pronouncements

A detail of recent accounting pronouncements can be found in Note A – Organization on Accounting Policies.

Off-Balance Sheet Arrangement

The Company does not have any off-balance sheet arrangements.

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Risk

Our primary market risk exposure is in the price we receive for our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot regional market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

We have entered into several commodity derivative contracts to hedge our exposure to commodity price risk associated with anticipated future oil and gas production. We believe we will have more predictability of our crude oil and gas revenues as a result of these derivative contracts.

The following table summarizes our open financial derivative positions as of December 31, 2016 related to oil and gas production.

Product	Type	Contract Period	Volume	Price per Mcf or Bbl
BRENT Oil	Collar	01/01/17 - 12/31/17	250 Bbl/d	$ 42.00 – 57.25
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 42.00 – 60.00
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 42.00 – 60.50
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 43.00 – 61.50
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 42.00 – 59.60
BRENT Oil	Swap	01/01/17 - 12/31/17	100 Bbl/d	$ 55.30
BRENT Oil	Swap	01/01/17 - 12/31/17	250 Bbl/d	$ 56.25
CIG Basis	Swap	01/01/17 - 03/31/19	7,500 MMBtu/d	$ (0.36)
DTI Basis	Swap	01/01/17 - 03/31/17	10,000 MMBtu/d	$ (0.86)
DTI Basis	Swap	01/01/17 - 03/31/19	10,000 MMBtu/d	$ (0.98)
DTI Basis	Swap	01/01/17 - 03/31/19	10,000 MMBtu/d	$ (1.04)
NYMEX Gas	Collar	01/01/17 - 12/31/17	15,000 MMBtu/d	$ 2.80 – 3.10
NYMEX Gas	Collar	01/01/17 - 12/31/18	10,000 MMBtu/d	$ 2.80 – 3.15
NYMEX Gas	Collar	01/01/18 - 12/31/18	10,000 MMBtu/d	$ 2.80 – 3.30
NYMEX Gas	Swap	01/01/17 - 03/31/18	10,000 MMBtu/d	$ 3.56
NYMEX Gas	Swap	01/01/17 - 07/31/17	5,000 MMBtu/d	$ 3.55

Under a swap contract, the counterparty is required to make a payment to us if the index price for any settlement period is less than the fixed price, and we are required to make a payment to the counterparty if the index price for any settlement period is greater than the fixed price.

Interest Rate Risk

At December 31, 2016, we had debt outstanding under our Exit Credit Facility of $140.3 million. The annual interest rate on borrowings under the Exit Credit Facility is the sum of (i) the LIBOR rate (with a minimum LIBOR rate of 1%) plus 9.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid in cash, plus (ii) an amount equal to 1.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid-in-kind and added to the outstanding principal amount of the loans on each quarterly interest payment date. At present, the interest rate is 11%. During 2016, the Company incurred $3.5 million of interest under the Exit Credit Facility of which approximately $0.1 million of interest was accrued at December 31, 2016.

Financial Instruments

Our financial instruments consist of cash and cash equivalents, collateral security accounts, derivatives and other long-term liabilities. The carrying amounts of cash and cash equivalents approximate fair market value due to the highly liquid nature of these short-term instruments or they are reported at fair value. Derivatives and other long-term liabilities are recorded at the approximate fair value of such items.

Inflation and Changes in Prices

The general level of inflation affects our costs. Salaries and other general and administrative expenses are impacted by inflationary trends and the supply and demand of qualified professionals and professional services. Inflation and price fluctuations affect the costs associated with exploring for and producing natural gas and oil, which have a material impact on our financial performance.

Item 8: Financial Statements and Supplementary Data

See Report of Independent Registered Public Accounting Firm and Audited Financial Statements at Item 15.

Item 9: Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A: Controls and Procedures

Disclosure Controls and Procedures.

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Evaluations have been performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act). Based upon those evaluations, management, including the Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2016 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realties that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Chief Executive Officer and the Chief Financial Officer, as of December 31, 2016, have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. As defined in Exchange Act Rule 13a-15(f), internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer and effected by our Board of Directors, management and other personnel, 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 and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the 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 directors; 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.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2016 based on the criteria in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based upon this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2016.

The annual report on Form 10-K does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. As a smaller reporting company as defined in Rule 12b-2 of the Exchange Act, our management's report was not subject to attestation by our registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit us to provide only management's report in this annual report on Form 10-K.

Changes in Internal Control over Financial Reporting.

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

Item 9B: Other Information.

Not applicable.

PART III

Item 10: Directors, Executive Officers and Corporate Governance

Information required by this item will be provided in an amendment of Form-10K/A and is hereby incorporated by reference herein.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer can be found on the Company's internet website located at www.warrenresources.com. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company intends to disclose the information on its internet website. This information will remain on the website for at least 12 months.

Item 11: Executive Compensation

Information required by this item will be provided in an amendment on Form 10-K/A and is hereby incorporated by reference herein.

Item 12: Securities Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item will be provided in an amendment on Form 10-K/A and is incorporated herein by reference.

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

Information required by this item will be provided in an amendment on Form 10-K/A and is hereby incorporated by reference herein.

Item 14: Principal Accountant Fees and Services

Information required by this item will be provided in an amendment on Form 10-K/A and is hereby incorporated by reference herein.

PART IV

Item 15: Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

(a)(2) All other schedules have been omitted because the required information is inapplicable or is shown in the Notes to the Consolidated Financial Statements.

(a)(3) Exhibits required to be filed by Item 601 of Regulation S-K.

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K and are incorporated herein by reference.

Item 16: Form 10-K Summary

None.

Table of Contents

Index to Financial Statements

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Warren Resources, Inc.

We have audited the accompanying consolidated balance sheet of Warren Resources, Inc. and its subsidiaries (collectively, the "Company") as of December 31, 2016 and the related consolidated statements of operations, stockholders' deficit, and cash flows for three month period ended December 31, 2016 and the nine month period ended September 30, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and schedule 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 an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Successor Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Warren Resources, Inc. and its subsidiaries as of December 31, 2016, and the consolidated results of their operations and their cash flows for the three months period ended December 31, 2016 and the nine months ended September 30, 2016, in conformity with accounting principles generally accepted in the United States of America.

We also have audited the adjustments to the 2015 financial statements to retrospectively apply the change in method of accounting for debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability due to the adoption of ASU 2015-03, Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs, as described in Note A to the financial statements. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2015 financial statements of the Company other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2015 financial statements taken as a whole.

/s/ MaloneBailey, LLP
www.malonebailey.com
Houston, Texas
April 7, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Warren Resources, Inc.

We have audited, before the effects of the adjustments to retrospectively apply the change in accounting described in Note A, the consolidated balance sheet of Warren Resources, Inc. (a Maryland corporation) and subsidiaries (the "Company") as of December 31, 2015, and the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity (deficit), and cash flows for the year then ended (the 2015 consolidated financial statements before the effects of the adjustments discussed in Note A are not presented herein). These 2015 consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the 2015 consolidated financial statements referred to above, which are before the effects of the adjustments to retrospectively apply the change in accounting described in Note A, present fairly, in all material respects, the financial position of Warren Resources, Inc. and subsidiaries as of December 31, 2015, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The 2015 consolidated financial statements were prepared assuming that the Company would continue as a going concern. As discussed in Note A in the previously filed 2015 financial statements, which is not presented herein, the Company incurred a net loss of approximately $620 million during the year ended December 31, 2015, and as of that date, the Company's current liabilities exceeded its current assets by approximately $465.1 million and its total liabilities exceeded its total assets by approximately $323.6 million. Also discussed in that Note A, subsequent to December 31, 2015, the Company was in default on its unsecured senior notes, first lien credit facility and second lien credit facility. These conditions, along with other matters as set forth in that Note A, raised substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in that Note A. The 2015 consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively apply the change in accounting described in Note A, and accordingly, we do not express an opinion or any other form of assurance about whether such adjustments are appropriate and have been properly applied. Those adjustments were audited by MaloneBailey, LLP.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 17, 2016

Table of Contents

Index to Financial Statements

WARREN RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)

	Successor December 31, 2016	Predecessor December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 5,642	$ 26,764
Accounts receivable, net of allowance for doubtful accounts of $808 and $15 at December 31, 2016 and 2015, respectively	10,847	9,880
Restricted investments in U.S. Treasury Bonds - available for sale at fair value (amortization costs of $- and $1,138 in 2016 and 2015, respectively)	—	1,448
Derivative financial instruments	587	11,081
Other current assets	4,503	5,439
Total current assets	21,579	54,612
Noncurrent Assets		
Oil and gas properties - at cost, based on full cost method of accounting, net of accumulated depreciation, depletion and impairment (includes unproven properties excluded from depletion of $- and $14,658 in 2016 and 2015, respectively)	68,363	162,685
Property and equipment - at cost, net	30,913	1,548
Other assets	3,036	3,107
Total other assets	102,312	167,340
	$ 123,891	$ 221,952
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities		
Accounts payable and accrued expenses	14,218	42,971
Current maturities on other long-term debt	—	153
First Lien Credit Facility, net of debt issuance costs of $4,980	—	229,685
Second Lien Credit Facility, net of debt issuance costs of $1,952	—	72,960
Senior Notes, net of debt issuance costs of $5,482	—	159,885
Convertible Debentures, net of debt issuance costs of $96	—	1,540
Short-term derivatives	6,313	—
Total current liabilities	20,531	507,194
Noncurrent liabilities		
Long-term debt-related party	140,320	—
Other long-term liabilities	39,229	38,322
Total liabilities	200,080	545,516
Commitments and contingencies		
Stockholders' Equity (Deficit)		
8% convertible preferred stock, par value $.0001; authorized 10,000,000 shares, issued and outstanding, 10,703 shares in 2015, (aggregate liquidation preference $128,437 in 2015)	—	128
Common stock, $.01 par value, authorized 100,000,000 shares, 10,000,000 shares issued in 2016; $.001 par value, authorized 100,000,000 shares, 85,203,466 issued in 2015	100	9
Additional paid-in capital	90,824	516,715
Accumulated deficit	(167,113)	(840,606)
Accumulated other comprehensive income, net of applicable income taxes	—	190
Total stockholders' equity (deficit)	(76,189)	(323,564)
	$ 123,891	$ 221,952

The accompanying notes are an integral part of these statements.

Table of Contents

Index to Financial Statements

WARREN RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except share and per share data)

	Successor	Predecessor	
	Three months ended December 31, 2016	Nine months ended September 30, 2016	Year ended December 31, 2015
Operating Revenues			
Oil and gas sales	$ 16,862	$ 39,712	$ 83,734
Transportation revenue	977	3,205	4,639
Total revenues	17,839	42,917	88,373
Operating Expenses			
Lease operating expenses and taxes	10,678	32,611	49,557
Depreciation, depletion and accretion	10,837	18,885	66,159
Impairment expense	145,117	87,094	578,323
Transportation expense	459	1,048	1,706
General and administrative	3,349	8,864	17,703
Reorganization items	—	14,171	—
Total operating expenses	170,440	162,673	713,448
Loss from operations	(152,601)	(119,756)	(625,075)
Other income (expense)			
Interest and other income	11	537	5,621
Interest expense, net (includes contractual interest expense on debt subject to compromise of $13,040 the nine months ended September 30, 2016)	(3,649)	(31,812)	(30,403)
Gain (loss) on financial instruments	(10,874)	1,131	20,083
Loss on contingent consideration	—	(430)	(540)
Gain on debt extinguishment	—	—	14,407
Troubled debt restructuring expense	—	—	(4,039)
Total other income (expense)	(14,512)	(30,574)	5,129
Loss before provision for income taxes	(167,113)	(150,330)	(619,946)
Deferred income tax expense	—	124	17
Net loss	(167,113)	(150,454)	(619,963)
Less dividends and accretion on preferred shares	—	—	10
Net loss applicable to common stockholders	$ (167,113)	$ (150,454)	$ (619,973)
Loss per common share - Basic and diluted	($ 16.71)	($ 1.77)	($ 7.55)
Weighted average common shares outstanding - Basic and diluted	10,000,000	85,239,176	82,128,892

The accompanying notes are an integral part of these statements.

WARREN RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Successor	Predecessor	
	Three months ended December 31, 2016	Nine months ended September 30, 2016	Year ended December 31, 2015
Cash flows from operating activities:			
Net loss	$ (167,113)	$ (150,454)	$ (619,963)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Accretion of discount on available for sale debt securities	—	(393)	(69)
Accretion of discount on senior notes	—	214	426
Accretion of second lien premium	—	(3,539)	—
Amortization of deferred bond offering costs	—	1,783	4,655
Depreciation, depletion and accretion	10,837	18,885	66,159
Impairment of oil and gas properties	145,117	87,094	578,323
Deferred tax benefit	—	124	17
Unrealized loss (gain) on derivative instruments	10,181	10,947	(7,076)
Loss on contingent consideration	—	430	540
Stock-based compensation	—	640	2,212
Bad debt expense	—	701	—
Gain on debt extinguishment	—	—	(14,407)
Change in assets and liabilities:			
Decrease in accounts receivable - trade	(4,243)	2,277	10,145
Decrease (increase) in other assets	236	868	(7,303)
Increase (decrease) in accounts payable and accruals	(2,462)	12,239	(8,255)
Decrease in other long term liabilities	—	—	(1,772)
Net cash provided by (used in) operating activities	(7,447)	(18,184)	3,632
Cash flows from investing activities:			
Purchase, exploration and development of oil and gas properties	(1,720)	(3,332)	(36,112)
Purchase of property and equipment	(225)	(110)	(254)
Liquidation of U.S. Treasury Bonds	—	1,527	—
Net cash used in investing activities	(1,945)	(1,915)	(36,366)
Cash flows from financing activities:			
Payments on debt issuance costs	—	(8)	—
Payments on debt and debentures	—	(1,623)	(289,860)
Proceeds from Credit Facility and Senior Note offerings	10,000	—	347,984
Payments on taxes of vested restricted stock and proceeds from the exercise of options	—	—	(329)
Net cash provided by (used in) financing activities	10,000	(1,631)	57,795
Net increase (decrease) in cash and cash equivalents	608	(21,730)	25,061
Cash and cash equivalents at beginning of period	5,034	26,764	1,703
Cash and cash equivalents at end of period	$ 5,642	$ 5,034	$ 26,764
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amounts capitalized	$ 3,200	$ 17,048	$ 21,763
Income taxes paid	—	—	—
Noncash investing and financing activities			
Accrued interest converted to debt	$ 320	$ 3,079	$ —
Accrued preferred stock dividend	—	—	10
Change in accounts payable relating to oil and gas property	—	—	(6,173)
Increase in asset retirement liability	—	—	9
Earn-Out provision for Citrus Acquisition	—	—	730
Farm-Out provision for Citrus Acquisition	—	—	(3,410)
Common stock issued for Second Lien Credit Facility	—	—	2,000
Noncash debt restructuring exchanges	—	—	40221

The accompanying notes are an integral part of these statements.

WARREN RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(in thousands)

	Successor	Predecessor	
	Three months ended December 31, 2016	Nine months ended September 30, 2016	Year ended December 31, 2015
Net loss	$ (167,113)	$ (150,454)	$ (619,963)
Other comprehensive loss:			
Gain (loss) on investments available for sale	—	(190)	(26)
Comprehensive loss	$ (167,113)	$ (150,644)	$ (619,989)

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity (Deficit)
Years ended December 31, 2016 and 2015
(in thousands)

	Preferred Stock		Common Stock		Additional Paid-In Capital	Accumulated Deficit	Accumulated other comprehensive income (loss)	Total Stockholders' Equity (Deficit)
	Shares	Amount	Shares	Amount				
Balance at December 31, 2014 (Predecessor)	11	$ 128	80,754	$ 8	$ 512,843	$ (220,643)	$ 216	$ 292,552
Shares issued and taxes paid from vesting of restricted stock	—	—	449	1	(330)	—	—	(329)
Shares issued from debt exchange	—	—	4,000	—	2,000	—	—	2,000
Dividends declared on preferred stock	—	—	—	—	(10)	—	—	(10)
Stock-based compensation	—	—	—	—	2,212	—	—	2,212
Net loss	—	—	—	—	—	(619,963)	—	(619,963)
Net change in unrealized gain on investment securities available for sale, net of applicable income tax	—	—	—	—	—	—	(26)	(26)
Balance at December 31, 2015 (Predecessor)	11	$ 128	85,203	$ 9	$ 516,715	$ (840,606)	$ 190	$ (323,564)
Shares issued and taxes paid from vesting of restricted stock	—	—	51	—	—	—	—	—
Stock-based compensation	—	—	—	—	640	—	—	640
Reverse preferred stock dividend	—	—	—	—	113	—	—	113
Net loss	—	—	—	—	—	(150,454)	—	(150,454)
Net change in unrealized gain on investment securities available for sale, net of applicable income tax	—	—	—	—	—	—	(190)	(190)
Balance at September 30, 2016 (Predecessor)	11	$ 128	85,254	$ 9	$ 517,468	$ (991,060)	$ —	$ (473,455)
Cancellation of Predecessor equity	(11)	(128)	(85,254)	(9)	(517,468)	991,060		473,455
Balance at September 30, 2016 (Predecessor)	—	$ —	—	$ —	$ —	$ —	$ —	$ —
Issuance of Successor common stock and warrants	—	—	10,000	100	90,824	—	—	90,924
Balance at September 30, 2016 (Successor)	—	$ —	10,000	$ 100	$ 90,824	$ —	$ —	$ 90,924
Net loss	—	—	—	—	—	(167,113)	—	(167,113)
Balance at December 31, 2016 (Successor)	—	$ —	10,000	$ 100	$ 90,824	$ (167,113)	$ —	$ (76,189)

The accompanying notes are an integral part of these statements.

WARREN RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2016 and 2015

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES

Nature of Operations

Warren Resources, Inc. (the "Company" or "Warren Resources" or "Warren"), was originally formed on June 12, 1990 for the purpose of acquiring and developing oil and gas properties. The Company was incorporated under the laws of the state of Maryland prior to its reincorporation in the state of Delaware effective October 5, 2016. The Company's properties are primarily located in California, Pennsylvania and Wyoming.

Reclassifications

Certain prior year amounts in the consolidated financial statements have been reclassified to conform to the current year presentation.

Emergence from Voluntary Reorganization under Chapter 11

On June 2, 2016, the Company and certain of its wholly owned subsidiaries (together with the Company, the "Debtors") filed voluntary petitions (the "Bankruptcy Petitions") for reorganization (the "Chapter 11 Cases") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"), Case No. 16-32760. The Debtors continued to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The subsidiary Debtors in the Chapter 11 Cases were Warren E&P, Inc. ("Warren E&P"), Warren Resources of California, Inc. ("Warren California"), Warren Marcellus, LLC ("Warren Marcellus"), Warren Energy Services, LLC and Warren Management Corp., which represent all subsidiaries of the Company. On September 14, 2016, the Bankruptcy Court entered an order (the "Confirmation Order") approving the Plan of Reorganization of Warren Resources, Inc. and Its Affiliated Debtors (as amended and supplemented, the "Plan"). On October 5, 2016 (the "Effective Date"), the Plan became effective pursuant to its terms, and the Debtors completed their reorganization under the Bankruptcy Code.

The description of the Plan can be found in its entirety by reference to the full text of the Confirmation Order, filed as Exhibit 2.1 to the Company's Current Report on Form 8-K with the Securities and Exchange Commission (the "SEC") on September 20, 2016.

Principles of Consolidation

The consolidated financial statements include accounts of the Company, its wholly-owned subsidiaries, Warren Development Corp., Warren Drilling Corp., Warren Management Corp., Warren Resources of California, Inc., Warren Energy Services LLC, Warren Marcellus LLC and Warren E&P, Inc. All significant intercompany accounts and transactions have been eliminated in consolidation.

Related Parties

A party is considered to be related to the Company if the party directly or indirectly or through one or more intermediaries, controls, is controlled by, or is under common control with the Company. Related parties also include principal owners of the Company, its management, members of the immediate families of principal owners of the Company and its management and other parties with which the Company may deal if one party controls or can significantly influence the management or operating policies of the other to an extent that one of the transacting parties might be prevented from fully pursuing its own separate interests. A party which can significantly influence the management or operating policies of the transacting parties or if it has an ownership interest in one of the transacting parties and can significantly influence the other to an extent that one or more of the transacting parties might be prevented from fully pursuing its own separate interests is also a related party.

Reorganization Items

The Company and the Chapter 11 Subsidiaries have incurred significant one-time costs associated with their reorganization under the Bankruptcy Code, principally professional and legal fees. The amount of these costs, which are being expensed as incurred, significantly affect our results of operations. For the year ended December 31, 2016, restructuring costs amounted to $14.2 million.

Oil and Gas Properties

The Company accounts for its oil and gas activities using the full cost method. As prescribed by full cost accounting rules, all costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of oil and gas properties as well as other internal costs that can be specifically identified with acquisition, exploration and development activities are also capitalized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs are depleted on the equivalent unit-of-production method, based on proved oil and gas reserves as determined by independent petroleum engineers.

In accordance with full cost accounting rules, the Company is subject to a limitation on capitalized costs. The capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10 percent, plus the cost of unproved properties excluded from

amortization, as adjusted for related tax effects. If capitalized costs exceed this limit (the "ceiling limitation"), the excess must be charged to expense. The Company recorded impairment expenses of $145 million in the three months ended December 31, 2016 (Successor), $87 million in the nine months ended September 30, 2016 (Predecessor) and $578 million in the year ended December 31, 2015 (Predecessor).

The costs of certain unevaluated oil and gas properties and exploratory wells being drilled are not included in the costs subject to amortization. The Company assesses costs not being amortized for possible impairments or reductions in value and if impairments or a reduction in value has occurred. An impairment of unevaluated oil and gas properties of $184 million was recorded for the year ended December 31, 2015.

Revenue Recognition

Oil and gas sales result from undivided interests held by the Company in various oil and gas properties. Sales of natural gas and oil produced are recognized when delivered to, or picked up by, the purchaser. For 2016, the largest purchasers and marketers of our total oil and gas production were Phillips 66, Clearwater Enterprises and Devlar Energy, which accounted for 58%, 35% and 6%, respectively, of total oil and natural gas sales sold in 2016. For 2015, the largest purchasers and marketers of our total oil and gas production were Phillips 66, Clearwater Enterprises and Devlar Energy, which accounted for 48%, 41% and 9%, respectively, of total oil and natural gas sales sold in 2015.

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less when acquired to be cash equivalents. The Company maintains its cash and cash equivalents in bank deposit accounts that may exceed federally insured limits. At December 31, 2016, the Company had the majority of its cash and cash equivalents with one financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on cash and cash equivalents.

Accounts Receivable

Accounts receivable include trade receivables from joint interest owners and oil and gas purchasers. Credit is extended based on evaluation of a customer's financial condition and, generally, collateral is not required. Accounts receivable under joint operating agreements generally have a right of offset against future oil and gas revenues if a producing well is completed. Accounts receivable are due within 30 days and are stated at amounts due from customers net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time trade accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. As of December 31, 2016 and 2015, the Company has an allowance of $808,000 and $16,000 respectively, for doubtful accounts.

Investments

The Company classifies its investment in debt securities as available-for-sale securities. Available-for-sale securities are recorded at fair value, with net unrealized gains and losses excluded from net earnings and reported as other comprehensive income (loss). Available-for-sale securities represent the market value of zero coupon Treasury Bonds collateralizing convertible debentures and are classified as current or non-current based on the classification of the related debentures. Realized gains and losses are determined on the basis of specific identification of the securities.

Offering Costs

Costs incurred in connection with the issuance of debt are capitalized and amortized over the term of the related debt using the straight-line method, which approximates the effective interest rate method. The Company had $- million (Successor) and $12.5 million (Predecessor), net of accumulated amortization of $- million (Successor) and $4.7 million (Predecessor), included as a direct deduction from the carrying amount of the associated debt liability at December 31, 2016 and 2015, respectively. Costs associated with the issuance of preferred and common stock are reflected as a reduction of proceeds.

Income Taxes

Deferred income taxes are recognized for the tax consequences in future years of differences between the tax basis of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory rates applicable to the period in which the differences are expected to affect taxable income. Valuation allowances are established when, in management's opinion, it is more likely than not that a portion or all of the deferred tax assets will not be realized. The Company's policy is to classify accrued penalties and interest related to unrecognized tax benefits in the Company's income tax provision. The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. Only tax positions that meet the more-likely-than-not recognition threshold are recorded.

Use of Estimates

In preparing financial statements, accounting principles generally accepted in the United States of America require management to make estimates and assumptions in determining the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In addition, significant estimates are used in determining year end proved oil and gas reserves. Actual results could differ from those estimates. The estimate of the Company's oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment of oil and gas properties, is the most significant of the estimates and assumptions that affect reported results.

Gas Imbalances

The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. The Company has no significant gas imbalances at December 31, 2016 or December 31, 2015.

Stock Based Compensation

The Company uses the Black-Scholes option-pricing formula and the Monte Carlo Simulation method to estimate the fair value of stock based compensation expense at the grant date related to stock options and certain restricted stock grants issued. This expense is then recognized using the straight-line method over the vesting period. For the nine months ended September 30, 2016 (Predecessor), the Company recognized approximately $0.6 million in compensation expense related to stock option plans and restricted stock. Compensation expense incurred during the year ended December 31, 2015 (Predecessor) amounted to $2.2 million Both the Black-Scholes and the Monte Carlo Simulation method require numerous assumptions, including volatility, service periods and cancellations in their calculations.

The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes options-pricing model with the following weighted average assumptions used for grants in 2015. No expected dividends, weighted average volatility of 64%, risk free interest rates of 1.23% and expected lives of 3.5 years for incentive options issued in 2015. The volatility assumptions were calculated based on the performance of our stock prices for the year. The weighted average per share fair values of the options issued in 2015 were $0.40. There were no stock options issued in 2016.

Accounting for Long-Lived Assets

The Company reviews property and equipment for impairment whenever indicators of impairment are present to determine if the carrying amounts exceed the estimated future net cash flows to be realized. Impairment losses are recognized based on the estimated fair value of the asset.

Derivative financial instruments

The Company has entered into several crude oil and natural gas hedges in order to minimize any effect of a downturn in oil and gas prices and protect profitability. These derivative financial instruments are carried on the balance sheet at fair value. If a derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. Gains and losses resulting from changes in the fair value of the non-designated hedges are recognized in earnings.

Property and Equipment

Property and equipment are stated at cost and are depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three to twenty-five years, except for land which is not depreciated. Property and equipment consisted of the following at December 31:

	Successor Year ended December 31, 2016	Predecessor Year ended December 31, 2015
	(in thousands)	
Drilling rig	$ —	$ 22,374
Equipment	21,592	1,503
Automobiles and trucks	278	801
Furniture and fixtures	—	522
Land and buildings	9,077	242
Office equipment	385	2,124
	31,332	27,566
Less accumulated depreciation and amortization	(419)	(26,018)
	$ 30,913	$ 1,548

During the year ended December 31, 2015, the Company recognized an impairment expense on their drilling rig of $16.7 million (Predecessor).

Earnings (Loss) Per Common Share

Basic earnings (loss) per common share is computed by dividing the net earnings (loss) applicable to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share is based on the assumption that stock options and warrants are converted into common shares using the treasury stock method and convertible debentures and preferred stock are converted using the if-converted method. Conversion or exercise is not assumed if the results are antidilutive.

	Successor Year ended December 31, 2016	Predecessor Year ended December 31, 2015
Weighted average shares outstanding—basic	10,000,000	82,128,892
Incremental shares issuable from dilutive stock options	—	—
Weighted average shares outstanding—diluted	10,000,000	82,128,892

Potential common shares relating to options, warrants, preferred stock, restricted stock and convertible debentures excluded from the computations of diluted earnings (loss) per share because they are anti-dilutive are as follows:

	Successor Year ended December 31, 2016	Predecessor Year ended December 31, 2015
Employee stock options	—	3,593,589
Convertible debentures	—	32,720
Preferred stock	—	5,352
Restricted stock	—	1,277,468
Warrants	526,316	—

Preferred stock was convertible from the date of issuance until redemption at 100% of the redemption price amount into common stock of the Company at a conversion rate between 1 to 1 and 1 to 0.5.

At December 31, 2015, the Convertible Debentures could be converted until maturity at 100% of principal amount into common stock of the Company at a price of $50.00.

Asset Retirement Obligations

The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a risk adjusted rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method. The associated liability is classified in other long-term liabilities, net of current portion, in the accompanying Consolidated Balance Sheets. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense, and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion and amortization. The Company has cash held in escrow with a fair market value of $2.9 million at December 31, 2016 and 2015 that is legally restricted for potential plugging and abandonment liability in the Wilmington field which is recorded in other assets in the Consolidated Balance Sheets. A reconciliation of the Company's asset retirement obligations is as follows:

Balance at December 31, 2014 (Predecessor)	$29,771
Liabilities incurred	9
Liabilities settled	(1,232)
Accretion expense	2,857
Balance at December 31, 2015 (Predecessor)	$31,405
Liabilities incurred	—
Liabilities settled	—
Accretion expense	2,248
Balance at September 30, 2016 (Predecessor)	$33,653
Fair value fresh-start adjustment	$ (22)
Balance at September 30, 2016 (Successor)	$33,631
Liabilities incurred	—
Liabilities settled	—
Accretion expense	1,277
Balance at December 31, 2016 (Successor)	$34,908

Capitalized Interest

The Company capitalizes interest on qualifying assets, which include investments in undeveloped oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress. The capitalized interest is determined by multiplying the Company's interest rate on specific borrowing costs, adjusted to include amortization of bond discount and issuance costs, by the qualifying costs incurred that are excluded from the full cost pool. However, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The capitalized interest amounts are recorded as additions to unevaluated oil and natural gas properties on the consolidated balance sheets. As the costs excluded are transferred to the full cost pool, the associated capitalized interest is also transferred to the full cost pool. Interest of $9.0 million was capitalized for the year ended 2015 and no interest amount was capitalized in 2016.

Recent Accounting Pronouncements

In May 2014, the FASB issued authoritative guidance that supersedes previous revenue recognition requirements and requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The FASB recently approved a delay which will make the updated guidance effective for fiscal years beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is not permitted. We are currently evaluating the effect the new standard will have on our financial statements and results of operations.

In August 2014, the FASB issued ASU No. 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 will explicitly require management to assess an entity's ability to continue as a going concern, and to provide related footnote disclosure in certain circumstances. The new standard was adopted by the Company, effective December 31, 2016.

In April 2015, the Financial Accounting Standards Board issued an Accounting Standards Update ("ASU") that is intended to simplify the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This ASU will be applied retrospectively as of the date of adoption and is effective for fiscal years beginning after December 15, 2015, and interim periods within those years (early adoption permitted). The Company has included the impact of the adoption of this ASU on its consolidated financial statements and related disclosures and reclassified $12.5 million of deferred bond offering costs to offset debt as of December 31, 2015.

In November 2015, the FASB issued authoritative guidance aimed at simplifying the accounting for deferred taxes. Current GAAP requires the deferred taxes for each jurisdiction (or tax-paying component of a jurisdiction) to be presented as a net current asset or liability and net noncurrent asset or liability. This requires a jurisdiction-by-jurisdiction analysis based on the classification of the assets and liabilities to which the underlying temporary differences relate, or, in the case of loss or credit carryforwards, based on the period in which the attribute is expected to be realized. Any valuation allowance is then required to be allocated on a pro rata basis, by jurisdiction, between current and noncurrent deferred tax assets. To simplify presentation, the new guidance requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. As a result, each jurisdiction will now only have one net noncurrent deferred tax asset or liability. Importantly, the guidance does not change the existing requirement that only permits offsetting within a jurisdiction – that is, companies are still prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. The guidance is effective for public business entities in fiscal years beginning after December 15, 2016, and interim periods thereafter. We do not expect this guidance to have a significant impact on our consolidated financial statements, other than balance sheet reclassifications.

In January 2016, the FASB issued authoritative guidance that amends existing requirements on the classification and measurement of financial instruments. The standard principally affects accounting for equity investments and financial liabilities where the fair value option has been elected. The guidance is effective for fiscal periods after December 15, 2017, and interim periods thereafter. Early adoption of certain provisions is permitted. We are currently evaluating the effect the new guidance will have on our financial statements and results of operations.

In February 2016, the FASB issued authoritative guidance that supersedes previous lease accounting requirements and requires that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods thereafter. Early adoption is permitted. We are currently evaluating the effect the new guidance will have on our consolidated financial statements and results of operations.

In March 2016, the FASB issued Accounting Standard Update (ASU) No. 2016-9, *Compensation-Stock Compensation* (ASU 2016-9). For public business entities, ASU 2016-9 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and early adoption is permitted. The areas for simplification in this ASU involve several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Some of the areas for simplification apply only to nonpublic entities. As there are multiple amendments in this ASU, the FASB has issued guidance on how an entity should apply each amendment, either prospectively or retrospectively. The Company is in the process of assessing the effects of the application on the new guidance.

In March 2016, the FASB issued ASU No. 2016-06, *Contingent Put and Call Options in Debt Instruments* (ASU 2016-06). For public business entities, ASU 2016-06 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and early adoption is permitted. ASU 2016-06 provides new guidance that simplifies the analysis of whether a contingent put or call option in a debt instrument qualifies as a separate derivative. An entity should apply the amendments in this ASU on a modified retrospective basis to existing debt instruments as of the beginning of the fiscal year for which the amendments are effective. The Company is in the process of assessing the effects of the application of the new guidance.

In August 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-15, Statement of Cash Flows (Topic 230) (ASU 2016-15). For public business entities, ASU 2016-15 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 and early adoption is permitted. The areas for simplification in this ASU involve addressing eight specific classification issues in the statement of cash flows. An entity should apply the amendments in this ASU using a retrospective transition method. The Company is in the early state of assessing the effects of the application of the new guidance.

NOTE B—REORGANIZATION

Bankruptcy Proceedings

On June 2, 2016, the Company and certain of its wholly owned subsidiaries (together with the Company, the “Debtors”) filed voluntary petitions (the “Bankruptcy Petitions”) for reorganization (the “Chapter 11 Cases”) under Chapter 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of Texas (the “Bankruptcy Court”), Case No. 16-32760. The Debtors continued to operate their businesses as “debtors-in-possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The subsidiary Debtors in the Chapter 11 Cases were Warren E&P, Inc., Warren Resources of California, Inc., Warren Marcellus, LLC, Warren Energy Services, LLC and Warren Management Corp., which represent all subsidiaries of the Company. On September 14, 2016, the Bankruptcy Court entered an order (the “Confirmation Order”) approving the Plan of Reorganization of Warren Resources, Inc. and Its Affiliated Debtors (as amended and supplemented, the “Plan”). On October 5, 2016 (the “Effective Date”), the Plan became effective pursuant to its terms, and the Debtors completed their reorganization under the Bankruptcy Code.

The description of the Plan can be found in its entirety by reference to the full text of the Confirmation Order, filed as Exhibit 2.1 to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission (the “SEC”) on September 20, 2016.

Termination of Material Definitive Agreements

First- and Second-Lien Credit Facilities

On the Effective Date, pursuant to the Plan, all amounts outstanding under the First Lien Credit Facility and Second Lien Credit Facility were cancelled and the obligations thereunder were terminated, released and discharged. Lenders under the First Lien Credit Facility and Second Lien Credit Facility received distributions of New Common Stock under the Plan. The Company also entered into the Exit Credit Facility with the lenders of the first-lien credit facility.

Indenture

On the Effective Date, pursuant to the Plan, the Company’s Senior Notes and the indenture governing the Senior Notes were cancelled and the obligations of the Debtors thereunder were terminated, released and discharged. Holders of the Senior Notes received distributions of New Common Stock under the Plan.

Convertible Debentures

As of September 30, 2016, pursuant to the Plan, holders of the Company’s Convertible Debentures received payment in full in cash such that the claim of such holders was unimpaired, and the trustees under each series of Convertible Debentures were paid reasonable and documented unpaid fees and expenses incurred on or before the Effective Date. The Convertible Debentures and the indentures governing each series of Convertible Debentures were cancelled and the obligations of the Debtors thereunder were terminated, released and discharged. Other than pursuant to the foregoing, holders of the Convertible Debentures did not receive distributions under the Plan in respect of the Convertible Debentures.

Equity Securities and Related Instruments

Pursuant to the Plan, on the Effective Date, the previously outstanding shares of the Prepetition Equity Securities, and the obligations of the Debtors thereunder were terminated, released and discharged. Holders of the Prepetition Equity Securities did not receive distributions under the Plan in respect of the Prepetition Equity Securities

Entry into a Material Definitive Agreements

New First Lien Exit Facility

On the Effective Date, pursuant to the Plan, the Company entered into a Credit Agreement by and among the Company, Wilmington Trust, National Association, as Administrative Agent (the “Agent”), and the lenders from time to time party thereto (the “Credit Agreement”). The Credit Agreement provides for a $150 million term loan facility (the “Exit Credit Facility”), consisting of initial senior secured term loans in an aggregate principal amount of $130 million (which, pursuant to the Plan, is deemed to be outstanding without any advancement of funds by the lenders under the Credit Agreement) and additional senior secured term loans (the “delayed draw term loans”) in an aggregate principal amount of up to $20 million, which, subject to the conditions set forth in the Credit Agreement, may be drawn from time to time by the Company.

The outstanding term loans, along with accrued and unpaid obligations with respect to such loans, under the Exit Credit Facility are subject to prepayment in respect of (i) proceeds from the issuance or incurrence of debt, excluding those items of debt permitted to be issued or incurred under the Credit Agreement and (ii) casualty proceeds and proceeds received from asset dispositions, subject to limited reinvestment rights and certain excluded asset sales. The Exit Credit Facility is guaranteed by all of the Company's wholly owned subsidiaries (the "Guarantors"). The Exit Credit Facility is secured by substantially all of the oil and gas assets of the Company and the Guarantors, as well as all of the equity interests in the Guarantors. Certain third-party swap and derivative transactions may be secured pursuant to an intercreditor agreement on a *pari passu* basis with the same collateral securing the Exit Credit Facility.

Proceeds of the delayed draw term loans under the Exit Credit Facility may be used from time to time for lawful corporate purposes, including for working capital needs and to finance corporate and capital expenditures and permitted acquisitions of oil and gas properties and other assets related to the exploration, production, development, processing, gathering, storage and transportation of hydrocarbons.

The interest rate on borrowings under the Exit Credit Facility will be equal to the sum of (i) the LIBOR rate (with a minimum LIBOR rate of 1%) plus 9.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid in cash, plus (ii) an amount equal to 1.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid-in-kind and added to the outstanding principal amount of the loans on each quarterly interest payment date. Other than with respect to prepayments or during periods in which the outstanding principal amount of the loans and other obligations under the Exit Credit Facility is subject to an increased interest rate following the occurrence of an event of default under the Credit Agreement, interest on each loan under the Exit Credit Facility shall be due and payable on the next to last business day of each March, June, September and December and on May 22, 2020, the maturity date under the Credit Agreement (the "Maturity Date").

Stockholders Agreement

On the Effective Date, pursuant to the Plan, the Company entered into a Stockholders Agreement (the "Stockholders Agreement") by and among the Company and the stockholders named therein, providing for certain stockholders' rights and obligations. Among other things, the Stockholders Agreement provides for Board Compensation, Transfer Restrictions, Restrictions on Authority of Board, Information Rights, Registration Rights, Preemptive Rights, Draw-Along and Tag-Along Rights.

Warrant Agreement

On the Effective Date, pursuant to the Plan, the Company entered into the Warrant Agreement, pursuant to which the Company issued the Warrants to Claren Road. The Warrants may be exercised in whole or in part and only during the period (the "Exercise Period") commencing on the Effective Date and terminating at 5:00 p.m., Eastern time, on October 5, 2021 (the "Warrant Expiration Date"), at an exercise price of $10.50 per share. All Warrants not exercised on or before such time on the Warrant Expiration Date shall become void, and the rights of the holders of such warrants pursuant to the warrants, the Warrant Agreement or the Stockholders Agreement shall cease at such time on the Warrant Expiration Date. The Company may, subject to the Stockholders Agreement, extend the duration of the Warrants by delaying the Warrant Expiration Date.

Sales of Equity Securities

On the Effective Date, pursuant to the Plan:

- 7,899,537 shares of New Common Stock were issued to the lenders under the prepetition first-lien credit facility;
- 755,000 shares of New Common Stock were issued to the lenders under the prepetition second-lien credit facility;
- 1,284,818 shares of New Common Stock were issued pro rata to the holders of the Senior Notes; and
- 60,645 shares of New Common Stock were issued to parties involved in the Marcellus Acquisition.

The lenders under the prepetition second-lien credit facility are party to the Warrant Agreement, pursuant to which they received Warrants that are initially exercisable for an aggregate of 526,316 shares of New Common Stock. Additionally, 600,000 shares of New Common Stock were authorized to be issued under the 2016 Equity Compensation Plan. To date, no shares have been issued under this plan.

NOTE C—FRESH-START ACCOUNTING

The Restructuring was accounted for as a purchase and was effective October 5, 2016. However, due to the immateriality of the five day activity period from October 1, 2016 through October 5, 2016, the Restructuring was treated for accounting purposes as effective September 30, 2016. The Restructuring resulted in a new basis of accounting and the Company qualified for and adopted fresh-start accounting in accordance with the provisions set forth in ASC 852 as (i) the Reorganization Value of the Company's assets immediately prior to the date of confirmation was less than post-petition liabilities and allowed claims, and (ii) the holders of the existing voting shares of the Predecessor entity received less than 50% of the voting shares of the merging entity. Refer to Note 2, "*Reorganization*," for the terms of the Plan. Fresh-start accounting required the Company to present its assets, liabilities, and equity as if it were a new entity upon emergence from bankruptcy. The new entity is referred to as "Successor" or "Successor Company." However, the Company will continue to present financial information for any periods before adoption of fresh-start accounting for the Predecessor Company. The Predecessor and Successor companies may lack comparability, as required in ASC Topic 205, *Presentation of Financial Statements* (ASC 205). ASC 205 states financial statements are required to be presented comparably from year to year, with any exceptions to comparability clearly disclosed. Therefore, "black-line" financial statements are presented to distinguish between the Predecessor and Successor Companies.

Adopting fresh-start accounting results in a new financial reporting entity with no beginning retained earnings or deficit as of the fresh-start reporting date. Upon the application of fresh-start accounting, the Company allocated the Reorganization Value (the fair value of the Successor Company's total assets) to its individual assets based on their estimated fair values. The Reorganization Value is intended to represent the approximate amount a willing buyer would value the Company's assets immediately after the reorganization.

Reorganization Value is derived from an estimate of Enterprise Value, or the fair value of the Company's long-term debt, stockholders' equity and working capital. The Enterprise Value was derived from a valuation using an asset-based methodology of proved reserve, undeveloped acreage, other long-term asset values and other financial information, considerations and projections, applying a combination of the income, cost and market approaches as of the fresh-start reporting date of September 30, 2016.

The Company's principal assets are its oil and natural gas properties. For purposes of estimating the fair value of the Company's proved reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company's reserves and discounted using a weighted average cost of capital rate of 10%. Weighted average commodity prices utilized in the determination of the fair value of oil and natural properties were $48.24 per barrel of oil, $2.54 per MMBtu of natural gas, after adjustment for transportation fees and regional price differentials.

Although the Company believes the assumptions and estimates used to develop Enterprise Value and Reorganization Value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating these values are inherently uncertain and require judgement.

The following table reconciles the Company's Enterprise Value to the estimated fair value of the Successor's common stock as of (in thousands):

	September 30, 2016
Enterprise Value	$ 215,890
Plus: Cash	5,034
Less: Fair value of debt	(130,000)
Fair Value of Successor common stock	$ 90,924

The following table reconciles the Company's Enterprise Value to its Reorganization Value as of September 30, 2016 (in thousands):

	September 30, 2016
Enterprise Value	$ 215,890
Plus: Cash	5,034
Plus: Current liabilities	16,999
Plus: Noncurrent asset retirement obligation	33,632
Reorganization Value of Successor assets	$ 271,555

Condensed Consolidated Balance Sheet

The following illustrates the effects on the Company's consolidated balance sheet due to the reorganization and fresh-start accounting adjustments. The explanatory notes following the table below provide further details on the adjustments, including the Company's assumptions and methods used to determine fair value for its assets and liabilities. Amounts included in the table below are rounded to thousands.

	As of September 30, 2016			
	Predecessor Company	Reorganization Adjustments	Fresh-Start Adjustments	Successor Company
ASSETS				
Current assets				
Cash and cash equivalents	$ 5,034	$ —	$ —	$ 5,034
Accounts receivable	7,094	—	(521)(6)	6,573
Other current assets	5,498	—	(759)(6)	4,739
Derivative financial instruments	134	—	—	134
Total current assets	17,760	—	(1,280)	16,480
Noncurrent Assets				
Oil and gas properties	62,659	—	158,276(6)(7)	220,935
Property and equipment	1,176	—	29,931(6)(7)	31,107
Other assets	3,026	—	7(6)	3,033
Total other assets	66,861	—	188,214	255,075
	$ 84,621	$ —	$ 186,934	$271,555
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued expenses	$ 15,116	—	$ 1,883(6)	16,999
Total current liabilities	15,116	—	1,883	16,999
Noncurrent liabilities				
Other long-term liabilities	33,654	—	(22)(8)	33,632
Long-term debt	—	130,000(1)		130,000
Liabilities subject to compromise	509,306	(509,306)(2)	—	—
Total liabilities	558,076	(379,306)	1,861	180,631
Commitments and contingencies	—	—	—	—
Stockholders' Equity (Deficit)				
Predecessor preferred stock	128	(128)(3)	—	—
Predecessor common stock	9	(9)(3)	—	—
Predecessor additional paid-in capital	517,468	(517,468)(3)		—
Successor common stock	—	100(4)	—	100
Successor additional paid-in capital	—	90,824(4)	—	90,824
Accumulated deficit	(991,060)	805,987(5)	185,073(9)	—
Total stockholders' equity (deficit)	(473,455)	379,306	185,073	90,924
	$ 84,621	$ —	$ 186,934	$271,555

Reorganization adjustments

1) Reflects issuance of $130 million of debt from the Exit Credit Facility
2) Liabilities subject to compromise were as follows (in thousands):

Accounts payable and accrued expenses	$ 38,105
First Lien Credit Facility	230,532
Second Lien Credit Facility	71,617
Senior Notes	161,635
Convertible Debentures	(83)
Other long-term liabilities	7,500
Gain on settlement of liabilities subject to compromise	$509,306

3) Reflects the cancellation of Predecessor equity as follows (in thousands):

Predecessor preferred stock	$ 128
Predecessor common stock	9
Predecessor additional paid-in-capital	517,468
Cancellation of Predecessor Company equity	$517,605

4) Reflects the issuance of Successor equity as follows (in thousands):

Successor common stock	$ 100
Successor additional paid-in-capital	90,824
Issuance of Successor equity	$90,924

5) Reflects the cumulative effect of the reorganization adjustments of $806 million.

Fresh-start accounting adjustments

6) In estimating the fair value of its oil and natural gas and other properties, the Company used a combination of the income and market approaches. For purposes of estimating the fair value of the Company’s proved reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company’s reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 10% for proved reserves. Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $48.24 per barrel of oil and $2.54 per MMBtu of natural gas, after adjustment for transportation fees and regional price differentials. Amount reflects the reclassification of the Company’s gas pipeline cost from oil and gas properties into property and equipment. Other line item amounts reflects changes attributable to oil and gas operations.
7) For purposes of estimating the fair value of its gas pipeline, an income approach was used that estimated future cash flows associated with the assets over the remaining useful lives. The valuation included such inputs as estimated future production, gathering and compression revenues and operating expenses that were discounted at a weighted average cost of capital rate of 9.5%.

   For purposes of estimating the fair value of the land, an appraisal was performed by an independent third party appraisal firm.

8) Reflects the adjustment of asset retirement obligations to fair value using estimated plugging and abandonment costs as of September 30, 2016.
9) Reflects the cumulative effect of fresh-start accounting adjustments.

NOTE D— DEBT

Current maturing long-term debt, net of debt issuance costs and discounts, consisted of the following:

	Successor December 31, 2016	Predecessor December 31, 2015
	(in thousands)	
Exit Credit Facility	$ 140,320	$ —
First Lien Credit Facility	—	229,685
Second Lien Credit Facility	—	72,960
Convertible Debentures	—	1,540
Senior Notes	—	159,885
	140,320	464,070
Less current portion	—	(464,070)
Long-term portion	$ 140,320	$ —

Exit Credit Facility

On the Effective Date, pursuant to the Plan, the Company entered into a Credit Agreement by and among the Company, Wilmington Trust, National Association, as Administrative Agent (the "Agent"), and the lenders (related party) from time to time party thereto (the "Credit Agreement"). The Credit Agreement provides for a $150 million term loan facility (the "Exit Credit Facility"), consisting of initial senior secured term loans in an aggregate principal amount of $130 million (which, pursuant to the Plan, is deemed to be outstanding without any advancement of funds by the lenders under the Credit Agreement) and additional senior secured term loans (the "delayed draw term loans") in an aggregate principal amount of up to $20 million, which, subject to the conditions set forth in the Credit Agreement, may be drawn from time to time by the Company.

The outstanding term loans, along with accrued and unpaid obligations with respect to such loans, under the Exit Credit Facility are subject to prepayment in respect of (i) proceeds from the issuance or incurrence of debt, excluding those items of debt permitted to be issued or incurred under the Credit Agreement and (ii) casualty proceeds and proceeds received from asset dispositions, subject to limited reinvestment rights and certain excluded asset sales. The Exit Credit Facility is guaranteed by all of the Company's wholly owned subsidiaries (the "Guarantors"). The Exit Credit Facility is secured by substantially all of the oil and gas assets of the Company and the Guarantors, as well as all of the equity interests in the Guarantors. Certain third-party swap and derivative transactions may be secured pursuant to an intercreditor agreement on a *pari passu* basis with the same collateral securing the Exit Credit Facility. The Exit Credit Facility also includes certain covenants, including a net debt to EBITDA ratio as defined in the credit agreement.

Proceeds of the delayed draw term loans under the Exit Credit Facility may be used from time to time for lawful corporate purposes, including for working capital needs and to finance corporate and capital expenditures and permitted acquisitions of oil and gas properties and other assets related to the exploration, production, development, processing, gathering, storage and transportation of hydrocarbons.

The interest rate on borrowings under the Exit Credit Facility will be equal to the sum of (i) the LIBOR rate (with a minimum LIBOR rate of 1%) plus 9.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid in cash, plus (ii) an amount equal to 1.0% per annum on the aggregate outstanding principal amount of the loans outstanding, which shall be paid-in-kind and added to the outstanding principal amount of the loans on each quarterly interest payment date. Other than with respect to prepayments or during periods in which the outstanding principal amount of the loans and other obligations under the Exit Credit Facility is subject to an increased interest rate following the occurrence of an event of default under the Credit Agreement, interest on each loan under the Exit Credit Facility shall be due and payable on the next to last business day of each March, June, September and December and on May 22, 2020, the maturity date under the Credit Agreement (the "Maturity Date").

At any time on or prior to October 5, 2017, if the Company repays all or any part of the principal balance of any loan under the Exit Credit Facility, or there is an acceleration of the Company's obligations under the Exit Credit Facility following the occurrence and continuation of an event of default under the Credit Agreement and notice from the Agent of such acceleration or there occurs a substitution of any lender pursuant to the terms of the Credit Agreement, the Company will pay the Agent, for the benefit of all of the lenders (or in the case of substitution, the substituted lender), in addition to the amount so repaid, due or assigned and any accrued and unpaid interest thereon, a make-whole premium equal to the present value at such time, computed on such repayment or assignment date using a discount rate equal to the treasury rate plus 50 basis points of the amount of (i) 4% the principal amount of such loan so repaid, due or assigned and (ii) the interest that would have accrued on the principal balance of the applicable loan being repaid or so due or assigned from the date of repayment, acceleration or assignment through October 5, 2017 if such loan remained outstanding and were repaid one day after such date.

After October 5, 2017, if the Company repays all or any part of the principal balance of any loan under the Exit Credit Facility, or if there is an acceleration of the Company's obligations under the Exit Credit Facility following the occurrence and continuation of an event of default under the Credit Agreement and notice from the Agent of such acceleration or there occurs a substitution of any lender pursuant to the terms of the Credit Agreement, the Company will pay the Agent, for the benefit of all of the lenders (or in the case of substitution, the substituted lender), in addition to the amount so repaid, due or assigned and any accrued and unpaid interest thereon, a repayment premium equal to the product of (i) the principal amount of the loans so repaid, due or assigned multiplied by (ii) the applicable percentage set forth below:

Year	Percentage
October 6, 2017 through October 5, 2018	4%
October 6, 2018 through October 5, 2019	2%
October 6, 2019 and thereafter	0%

The Company is subject to affirmative and negative covenants under the Credit Agreement, including, but not limited to, financial covenants with respect to Consolidated Total Leverage Ratio (as such term is defined in the Credit Agreement) and minimum liquidity. The Consolidated Total Leverage

Ratio covenant requires that, commencing on June 30, 2017, the Consolidated Total Leverage Ratio for any period of four consecutive fiscal quarters shall not be greater than, determined as of the last day of each fiscal quarter, (a) during the period following June 30, 2017 until December 31, 2017, 5.5 to 1.0, (b) during the period following March 31, 2018 until December 31 , 2018, 5.0 to 1 .0 and (c) during the period following March 31, 2019 until the Maturity Date, 4.5 to 1.0. The minimum liquidity covenant requires that the Company and its Subsidiaries at all times maintain the aggregate amount of undrawn availability under the delayed draw term loans, unrestricted cash and cash equivalents of at least $5 million.

The Exit Credit Facility is subject to other usual and customary conditions, representations, warranties and covenants including, but not limited to, restrictions on additional indebtedness, liens, contingent obligations, payments, investments, mergers, asset dispositions, speculative commodity transactions, transactions with affiliates and other matters. The Exit Credit Facility is subject to customary events of default. If an event of default occurs and is continuing, the Agent may, or at the request of certain required lenders shall, accelerate amounts due under the Exit Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

The outstanding balance of the Exit Credit Facility at December 31, 2016 amounted to $140.3 million which includes $0.3 million of paid-in-kind interest.

First Lien Credit Facility and Senior Notes Exchange

On May 22, 2015, Warren Resources entered into a first lien credit agreement by and among the Company, Wilmington Trust, National Association, as Administrative Agent, and the lenders from time to time party thereto, that provides for a five-year, $250 million term loan facility (as amended, the “First Lien Credit Facility”) which matures on May 22, 2020. At the closing of the

First Lien Credit Facility, certain of the first lien lenders extended credit in the form of new term loans in the amount of $172.5 million and in the form of commitments for delayed draw term loans for up to an additional $30 million, subject to certain incurrence tests. Approximately $47 million in additional term loans were issued under the First Lien Credit Facility at closing in exchange for $69.59 million in face value of the 9.000% Senior Notes due 2022, as described further under “9.000% Senior Notes due 2022” below.

The conditions applicable to further draw downs under the First Lien Credit Facility were modified as part of the First Amendment to the First Lien Credit Facility that was entered into on October 22, 2015. The First Lien Credit Facility was guaranteed by Warren California, Warren E&P and Warren Marcellus, which are three of the Company’s wholly-owned subsidiaries, and was collateralized by substantially all of Warren’s assets, including the equity interests of the guarantors. Warren used the proceeds drawn at the closing of the First Lien Credit Facility to repay the balance on its former credit facility, and has been released from all legal obligations on such former facility. The Company accounted for this Exchange transaction in accordance with ASC 470 and ASC 405 and as a result recognized a gain on the retirement of debt in the amount of $14.4 million during 2015.

The First Lien Credit Facility is subject to prepayment in respect of asset sales, subject to limited reinvestment rights and certain excluded asset sales. The First Lien Credit Facility also includes certain covenants, including a maintenance covenant requiring the Company to maintain a minimum consolidated first lien leverage ratio. The terms of the maintenance covenant were modified as part of the First Amendment to the First Lien Credit Facility that was entered into on October 22, 2015.

The First Lien Credit Facility is subject to other usual and customary conditions, representations, and warranties, including restrictions on certain additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters. The First Lien Credit Facility is also subject to customary events of default. If an event of default occurs and is continuing, the Agent may, or at the request of certain required lenders shall, accelerate amounts due under the First Lien Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically, by their terms, become due and payable).

The annual interest rate on borrowings under the First Lien Credit Facility was 8.5% plus LIBOR for the applicable LIBOR period (with a minimum LIBOR rate of 1%) and was payable quarterly in arrears on the next to last business day of each March, June, September and December. At September 30, 2016 the interest rate was 9.5%.

On November 9, 2015, $15 million of additional borrowings were drawn depleting the total available under the facility.

On the Effective Date, pursuant to the Plan, all amounts outstanding under the First Lien Credit Facility were cancelled and the obligation thereunder terminated, released and discharged. Lenders under the First Lien Credit Facility received distributions of the Company’s common stock, par value $0.01 (the “New Common Stock”) under the Plan and entered into a new term loan facility with the Company (the Exit Credit Facility as discussed below).

Second Lien Credit Facility and Senior Note Exchange

On October 22, 2015, the Company entered into a second lien credit facility (the “Second Lien Credit Facility”) by and among the Company, Cortland Capital Market Services, LLC, as Administrative Agent, and the lenders from time to time party thereto. The Second Lien Credit Facility provided for a five-year, approximately $51.0 million term loan facility that matured on November 1, 2020. At closing, certain of the lenders exchanged approximately $63.1 million in face value of previously-issued Senior Notes held by them, plus accrued interest, for (i) approximately $40.1 million of second lien term loans under the Second Lien Credit Facility, and (ii) four million (4,000,000) shares of the Company’s Common Stock and, in addition, extended credit in the form of new second lien term loans in the amount of approximately $11.0 million. The annual interest rate on borrowings under the Second Lien Credit Facility was 12%, with interest payable semi-annually in arrears on each April 20 and October 20. On the first three semi-annual interest payment dates, beginning with April 20, 2016, the Company could elect to pay up to all of such interest (6% per semi-annual period) by capitalizing accrued and unpaid interest and adding the same to the principal amount of the second lien loans then outstanding. For the subsequent three semi-annual interest payment dates, beginning with October 20, 2017 and ending October 20, 2018, the Company could elect to pay up to one quarter of such interest (1.5% per semi-annual period) by capitalizing accrued and unpaid interest and adding the same to the principal amount of the Second Lien Loans then outstanding.

The transaction was accounted for as a troubled debt restructuring in accordance with ASC 470, whereby no gain on the retirement of debt was recognized and a premium on the issuance equal to the amount of debt retired could be amortized over the life of the instrument. The total outstanding balance at September 30, 2016 amounted to $71.6 million which was net of debt issuance costs of $1.6 million.

On the Effective Date, pursuant to the Plan, all amounts outstanding under the Second Lien Credit Facility were cancelled and the obligations thereunder terminated, released and discharged. Lenders under the Second Lien Credit Facility received distributions of New Common Stock under the Plan. Additionally, the lenders under the Second Lien Credit Facility were party to the Plan Warrant

Agreement, dated as of October 5, 2016, by and among the Company, and Claren Road Credit Master Fund, Ltd. and Claren Road Credit Opportunities Master Fund, Ltd. (collectively, "Claren Road") and the other registered holders from time to time party thereto, pursuant to which they received warrants exercisable, in accordance with the terms thereof, for an aggregate of 526,316 shares of New Common Stock (the "Warrants").

9.000% Senior Notes due 2022

On August 11, 2014, we acquired essentially all of the Marcellus Assets (the "Marcellus Assets") of Citrus Energy Corporation ("Citrus") and two other working interest owners (the "Marcellus Asset Acquisition"). To finance the Marcellus Asset Acquisition, on August 11, 2014, the Company issued 9.000% senior notes in a private offering at a price equal to 98.617% for a total of $300 million due to mature on August 1, 2022 (the "Unregistered Senior Notes"). Interest was payable on the Unregistered Senior Notes semi-annually in arrears at a rate of 9.000% per annum on each February 1 and August 1.

In connection with the First Lien Credit Facility entered into on May 22, 2015, the Company exchanged $69.59 million in face value of the Unregistered Senior Notes previously held by the lenders under the First Lien Credit Facility for approximately $45.23 million of first lien term loans plus accrued unpaid interest of $1.9 million rolled into the First Lien Term Loans as additional borrowing.

On July 27, 2015, substantially all of the outstanding Unregistered Senior Notes were exchanged for an equal principal amount of registered 9.000% Senior Notes due 2022 pursuant to a registration statement on Form S-4 that was declared effective by the SEC on June 19, 2015 under the Securities Act (the "Registered Senior Notes" and, together with the Unregistered Senior Notes, the "Senior Notes"). The Registered Senior Notes are identical to the Unregistered Senior Notes except that the Registered Senior Notes were registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest.

In connection with the Second Lien Credit Facility entered into on October 22, 2015, the Company exchanged $63.1 million in face value of Registered Senior Notes previously held by the lenders under the Second Lien Credit Facility for approximately $40.1 million of second lien term loans.

We could redeem, at specified redemption prices, some or all of the Senior Notes at any time on or after August 1, 2017. We could also redeem up to 35% of the Senior Notes using the proceeds of certain equity offerings completed before August 1, 2017. If we should sell certain of our assets or experience certain kinds of changes in control, we could be required to offer to purchase the Senior Notes from the holders. The Senior Notes were fully, unconditionally and jointly and severally guaranteed on a senior unsecured basis by certain of our existing subsidiaries and were fully, unconditionally and jointly and severally guaranteed on a senior unsecured basis by our future domestic subsidiaries, subject to certain exceptions. Warren is a holding company with no independent assets or operations. Any subsidiaries of the Company other than the subsidiary guarantors are minor. There were no significant restrictions on the Company's ability, or the ability of any subsidiary guarantor, to obtain funds from its subsidiaries through dividends, loans, advances or otherwise. The total outstanding balance at September 30, 2016 amounted to $161.6 million which was net of debt issuance costs of $3.9 million.

On the Effective Date, pursuant to the Plan, the Company's 9% Senior Notes due 2022 and the indenture governing the Senior Notes were cancelled and the obligations of the Debtors thereunder were terminated, released and discharged. Holders of the Senior Notes received distributions of New Common Stock under the Plan.

Convertible Debentures

Convertible debentures, net of debt issuance costs of $96,000, consisted of the following (in thousands):

	Maturity date	Successor December 31, 2016	Predecessor December 31, 2015
Secured Convertible 12% Debentures	December 31, 2020	$ —	$ 783
Secured Convertible 12% Debentures	December 31, 2022	—	757
		$ —	$ 1,540

As of September 30, 2016, pursuant to the Plan, holders of the Company's 12% Secured Convertible Bonds due December 31, 2020 and the 12% Secured Convertible Bonds due December 31, 2022 (together, the "Convertible Debentures") received payment in full in cash such that the claim of such holders was unimpaired, and the trustees under each series of Convertible Debentures were paid reasonable and documented unpaid fees and expenses incurred on or before the Effective Date. On the Effective Date, the Convertible

Debentures and the indentures governing each series of Convertible Debentures were cancelled and the obligations of the Debtors thereunder were terminated, released and discharged. Other than pursuant to the foregoing, holders of the Convertible Debentures did not receive distributions under the Plan in respect of the Convertible Debentures.

NOTE E—INVESTMENTS

The amortized cost, unrealized gains and estimated fair values of the Company's available-for-sale securities held are summarized as follows:

	Successor December 31, 2016	Predecessor December 31, 2015
	(in thousands)	
U.S. Treasury Bonds, stripped of interest, maturing 2020 and 2022, aggregate par value of $1.6 million		
Amortized cost	$ —	$ 1,138
Gross unrealized gains	—	310
Estimated fair value	$ —	$ 1,448

The unrealized gains for each year results from the disposition of such securities due to the release of the Company's obligation related to securing its commitment under debentures. The basis of the securities sold is determined using the specific identification method.

NOTE F—STOCKHOLDERS' EQUITY

Prepetition Equity Securities

Pursuant to the Plan, on the Effective Date, the previously outstanding shares of the Prepetition Equity Securities were terminated, released and discharged. Holders of the Prepetition Equity Securities did not receive distributions under the Plan in respect of the Prepetition Equity Securities.

Stockholders Agreement

On the Effective Date, pursuant to the Plan, the Company entered into a Stockholders Agreement (the "Stockholders Agreement") by and among the Company and the stockholders named therein, providing for certain stockholders' rights and obligations. Among other things, the Stockholders Agreement provides for Board Compensation, Transfer Restrictions, Restrictions on Authority of Board, Information Rights, Registration Rights, Preemptive Rights, Draw-Along and Tag-Along Rights.

New Common Stock

On the Effective Date, pursuant to the Plan:

- 7,899,537 shares of New Common Stock were issued to the lenders under the prepetition first-lien credit facility;
- 755,000 shares of New Common Stock were issued to the lenders under the prepetition second-lien credit facility;
- 1,284,818 shares of New Common Stock were issued pro rata to the holders of the Senior Notes; and
- 60,645 shares of New Common Stock were issued to parties involved in the Marcellus Acquisition.

The lenders under the prepetition second-lien credit facility are party to the Warrant Agreement, pursuant to which they received Warrants that are initially exercisable for an aggregate of 526,316 shares of New Common Stock. Additionally, 600,000 shares of New Common Stock were authorized to be issued under the 2016 Equity Compensation Plan. To date, no shares have been issued under this plan.

Warrant Agreement

On the Effective Date, pursuant to the Plan, the Company entered into the Warrant Agreement, pursuant to which the Company issued the Warrants to Claren Road. The Warrants may be exercised in whole or in part and only during the period (the "Exercise Period") commencing on the Effective Date and terminating at 5:00 p.m., Eastern time, on October 5, 2021 (the "Warrant Expiration Date"), at an exercise price of $10.50 per share. All Warrants not exercised on or before such time on the Warrant Expiration Date shall become void, and the rights of the holders of such warrants pursuant to the warrants, the Warrant Agreement or the Stockholders Agreement shall cease at such time on the Warrant Expiration Date. The Company may, subject to the Stockholders Agreement, extend the duration of the Warrants by delaying the Warrant Expiration Date.

Preferred Stock

The Company's preferred stock, pays an 8% cumulative dividend which is treated as a deduction of additional paid in capital due to insufficient retained earnings. Holders of the stock are not entitled to vote except as defined by the agreement or as provided by applicable law. The preferred stock may be voluntarily converted, at the election of the holder, into common stock of the Company based on a conversion rate of one share of preferred stock for 0.50 shares of common stock. The accrual of the dividend is deducted from earnings in the calculation of earnings attributable to common stockholders.

Additionally, holders of the preferred stock can elect to require the Company to redeem their preferred stock at a redemption price equal to the liquidation value of $12.00 per share, plus accrued but unpaid dividends, if any, ("Redemption Price"). Upon the receipt of a redemption election, the Company, at its option, shall either: (1) pay the holder cash in the amount equal to the Redemption Price or (2) issue to the holder shares of common stock in an amount equal to 125% of the redemption price and any accrued and unpaid dividends, based on the weighted average closing "bid" price of the Company's common stock for the thirty trading days immediately preceding the date of the written redemption election by the holder up to a maximum of 1.5 shares of common stock for each one share of preferred stock redeemed. The Company has accreted the carrying value of its preferred stock to its redemption price using the effective interest method with changes recorded to additional paid in capital. The accretion of preferred stock results in a reduction of earnings applicable to common stockholders.

Notwithstanding the forgoing, if the closing "bid" price of the Company's publicly traded common stock as reported by the NASDAQ stock market, or any exchange on which the shares of common stock are traded, exceeds 133% of the conversion price then in effect for the convertible preferred shares for at least 10 days during any 30-day trading period, the Company has the right to redeem in whole or in part the convertible preferred stock at a redemption price of $12 per share (plus any accrued unpaid dividends) or convert the convertible preferred shares (plus any accrued unpaid dividends) into common stock at the then applicable conversion rate.

Pursuant to the Plan, on the Effective Date, all outstanding shares of Preferred Stock were terminated, released and discharged. Holders of Preferred Stock did not receive distributions under the Plan.

Securities Authorized for Issuance Under Compensation Plans

The Company utilizes restricted stock and stock options to compensate employees, officers, directors and consultants. Total stock-based compensation expense related to stock options and restrictive stock awards amounted to $0.6 million for the nine months ended September 30, 2016 (Predecessor) and $2.2 million for the year ended December 31, 2015 (Predecessor). No such expenses were incurred for the three months ended December 31, 2016 (Successor).

A summary of the Company's stock options is as follows:

	Incentive options	Weighted Average Exercise Price
Options outstanding at December 31, 2014 (Predecessor)	1,987,159	$ 4.37
Issued	2,730,400	$ 0.88
Exercised	—	—
Forfeited or expired	(1,123,970)	$ 2.64
Outstanding at December 31, 2015 (Predecessor)	3,593,589	$ 2.26
Issued	—	—
Exercised	—	—
Forfeited or expired	(1,085,882)	$ 2.44
Cancelled	(2,507,707)	$ 2.21
Outstanding at September 30, 2016 (Predecessor)	—	$ —

A summary of the Company's restricted stock is as follows:

	Shares	Weighted Average Fair Value
Outstanding at December 31, 2014 (Predecessor)	689,370	$ 2.87
Granted	1,669,655	0.56
Vested	(697,630)	1.79
Forfeited	(383,927)	2.06
Outstanding at December 31, 2015 (Predecessor)	1,277,468	$ 0.69
Granted	—	—
Vested	(83,884)	3.70
Forfeited	(21,097)	3.70
Cancelled	(1,172,487)	0.41
Outstanding at September 30, 2016 (Predecessor)	—	$ —

NOTE G—FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of financial instruments recognized in the Consolidated Balance Sheets or disclosed within these Notes to Consolidated Financial Statements have been determined using available market information, information from unrelated third party financial institutions and appropriate valuation methodologies, primarily discounted projected cash flows. However, considerable judgment is required when interpreting market information and other data to develop estimates of fair value.

Short -term Assets and Liabilities. The fair values of cash and cash equivalents, accounts receivable, accounts payable and accrued expenses and other current liabilities approximate their carrying values because of their short-term nature.

U.S. Treasury Bonds—Available-For-Sale Securities. The fair values are based upon quoted market prices for those or similar investments and are reported on the Consolidated Balance Sheets at fair value.

Collateral Security Agreement Account (included in other non-current assets). The balance sheet carrying amount approximates fair value, as it earns a market rate.

Fixed Rate Debentures. Fair values of fixed rate convertible debentures were calculated using interest rates in effect as of year end for similar instruments with the other terms unchanged.

Other Long-Term Liabilities. The carrying amount approximates fair value due the current rates offered to the Company for long-term liabilities of the same remaining maturities.

First Lien Credit Facility. The carrying amount approximates fair value due to the current rate stipulated in the first lien credit facility agreement.

Second Lien Credit Facility. The carrying amount approximates fair value due to the current rate stipulated in the second lien credit facility agreement inclusive of capitalized interest paid in kind.

Derivative Financial Instruments. The fair values are based upon observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs) and are reported on the Consolidated Balance Sheets at fair value.

9.000% Senior Notes. The fair value is based upon quoted market prices for those or similar investments and are reported on the Consolidated Balance Sheets at face value, net of discount.

Contingent Earn-Out. The fair value is based on the present value of the amount discounted at the cost of capital.

	Successor		Predecessor	
	2016		2015	
	Fair value	Carrying amount	Fair value	Carrying amount
	(in thousands)			
Financial assets:				
Collateral Security account	$ 2,952	$ 2,952	$ 2,812	$ 2,812
U.S. Treasury Bonds	—	—	1,448	1,636
Derivative Assets	587	5,87	11,081	11,081
Financial liabilities:				
Exit Credit Facility	140,320	140,320	—	—
Derivative Liability	10,633	10,633	—	—
Fixed rate debentures	—	—	3,057	1,636
First Lien Credit Facility	—	—	234,665	234,665
Second Lien Credit Facility	—	—	74,912	74,912
Senior Notes	—	—	25,090	165,368

FAIR VALUE MEASUREMENTS:

Fair value as defined by authoritative literature is 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. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions utilized to measure the fair value of the Company's commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). The fair value of our commodity derivatives were determined through a discounted cash flow model, using terms of the derivative instruments, market prices for the periods covered by the derivatives, and the credit adjusted risk-free interest rates.

The following table presents for each hierarchy level our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis.

December 31, 2016 (Successor)	Level 1	Level 2	Level 3	Total
		(in thousands)		
Current Assets				
Derivative Financial Instruments	$ —	$ 587	$ —	$ 587
Current Liabilities				
Derivatives Financial Instruments	$ —	$6,313	$ —	$6,313
Noncurrent Liabilities				
Derivative Financial Instruments	$ —	$4,320	$ —	$4,320

December 31, 2015 (Predecessor)	Level 1	Level 2	Level 3	Total
		(in thousands)		
Current Assets				
U.S. Treasury Bonds—Available-For-Sale Securities	$1,448	$ —	$ —	$ 1,448
Derivative Financial Instruments	$ —	$11,081	$ —	$11,081

NOTE H—DERIVATIVE FINANCIAL INSTRUMENTS

To minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices. This price hedging program is designed to moderate the effects of a crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate. Currently, our more commonly used derivatives are in the form of swaps. However, we may use a variety of derivative instruments in the future to hedge. The Company has not designated these derivatives as hedges.

The following table summarizes the open financial derivative positions as of December 31, 2016 related to oil and gas production. The Company will receive prices as noted in the table below and will pay a counterparty market price based on the NYMEX (for natural gas production) or WTI (for oil production) index price, settled monthly.

Product	Type	Contract Period	Volume	Price per Mcf or Bbl
BRENT Oil	Collar	01/01/17 - 12/31/17	250 Bbl/d	$ 42.00 – 57.25
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 42.00 – 60.00
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 42.00 – 60.50
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 43.00 – 61.50
BRENT Oil	Collar	01/01/17 - 12/31/18	250 Bbl/d	$ 42.00 – 59.60
BRENT Oil	Swap	01/01/17 - 12/31/17	100 Bbl/d	$ 55.30
BRENT Oil	Swap	01/01/17 - 12/31/17	250 Bbl/d	$ 56.25
CIG Basis	Swap	01/01/17 - 03/31/19	7,500 MMBtu/d	$ (0.36)
DTI Basis	Swap	01/01/17 - 03/31/17	10,000 MMBtu/d	$ (0.86)
DTI Basis	Swap	01/01/17 - 03/31/19	10,000 MMBtu/d	$ (0.98)
DTI Basis	Swap	01/01/17 - 03/31/19	10,000 MMBtu/d	$ (1.04)
NYMEX Gas	Collar	01/01/17 - 12/31/17	15,000 MMBtu/d	$ 2.80 – 3.10
NYMEX Gas	Collar	01/01/17 - 12/31/18	10,000 MMBtu/d	$ 2.80 – 3.15
NYMEX Gas	Collar	01/01/18 - 12/31/18	10,000 MMBtu/d	$ 2.80 – 3.30
NYMEX Gas	Swap	01/01/17 - 03/31/18	10,000 MMBtu/d	$ 3.56
NYMEX Gas	Swap	01/01/17 - 07/31/17	5,000 MMBtu/d	$ 3.55

The tables below summarize the amount of gains (losses) recognized in income from derivative instruments not designated as hedging instruments under authoritative guidance (in thousands).

Derivatives not designated as Hedging Instrument under authoritative guidance	Successor For the three months ended December 31, 2016	Predecessor For the nine months ended September 30, 2016	Predecessor For the Year Ended December 31, 2015
		(in thousands)	
Realized cash settlements on hedges	$ (693)	$ 11,741	$ 13,007
Unrealized gain (loss) on hedges	(10,181)	(10,947)	7,076
Total gain (loss)	$ (10,874)	$ 794	$ 20,083

The table below reflects the line item in our Consolidated Balance Sheet where the fair value of our net derivatives, are included.

December 31, 2016 (Successor)	Balance Sheet Location	Fair Value
	(in thousands)	
Commodity—Natural Gas	Current assets	$ 587
Total derivatives not designated as hedging instruments		$ 587
	(in thousands)	
Commodity—Oil	Current liabilities	$ 1,562
Commodity—Natural Gas	Current liabilities	4,751
Total derivatives not designated as hedging instruments		$ 6,313
	(in thousands)	
Commodity—Oil	Other long-term liabilities	$ 1,615
Commodity—Natural Gas	Other long-term liabilities	2,705
Total derivatives not designated as hedging instruments		$ 4,320

December 31, 2015 (Predecessor)	Balance Sheet Location	Fair Value
	(in thousands)	
Commodity—Natural Gas	Current assets	$ 7,816
Commodity—Oil	Current assets	3,265
Total derivatives not designated as hedging instruments		$ 11,081

Derivatives Credit risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts.

The Company's derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company were to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time.

NOTE I—INCOME TAXES

The Company and its subsidiaries file a consolidated federal income tax return.

The Company's effective income tax rate differed from the federal statutory rate as follows:

	December 31, 2016	September 30, 2016	2015
		(in thousands)	
Income Taxes at Federal Statutory Rate	$ (56,818)	$ (51,112)	$(210,781)
Change in Valuation Allowance	36,912	60,625	251,045
Nondeductible Expenses	4	(788)	(2,523)
State Income Taxes Net of Federal Benefit	(6,618)	(5,953)	(37,197)
Section 382 NOL Reduction	26,520	—	—
Other	—	(2,648)	(527)
	—	124	17

	December 31, 2016	September 30, 2016	2015
		(in thousands)	
Deferred Tax Assets Relating To:			
Net Operating Loss Carryforward	159,636	176,741	130,816
Oil and Gas Properties and Tangible Equipment	195,957	219,440	228,324
Stock Option Expense	—	4,564	4,207
Unrealized Loss on Derivatives	4,036	—	—
Other	1,147	1,105	719
	360,776	401,850	364,066
Less Valuation Allowance	360,553	401,800	359,510
Total Deferred Tax Asset	223	50	4,556
Deferred Tax Liabilities Relating To:			
Unrealized Gain on Derivatives	(223)	(50)	(4,432)
Net Unrealized Gain on Investments	—	—	(124)
Total Deferred Tax Liability	(223)	(50)	(4,556)
Net Deferred Tax Asset (Liability)	—	—	—

A valuation allowance for deferred tax assets is required when it is more-likely-than-not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of this deferred tax asset depends on the Company’s ability to generate sufficient taxable income in the future. Management believes it is more-likely-than-not that the net deferred tax asset will not be realized by future operating results. The valuation allowance decreased by approximately $41 million for the 3 month period ended December 31, 2016 and increased by approximately $42 million for the 9 month period ended September 30, 2016.

At December 31, 2016, the Company had net operating loss carryforwards for federal income tax purposes of approximately $421 million, which will expire in years 2019 through 2035.

Tax years beginning in 2013 are subject to examination by taxing authorities, although net operating loss and credit carryforwards from all years are subject to examination and adjustments for at least three years following the year in which the attributes are used.

The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. Only tax positions that meet the more-likely-than-not recognition threshold are recorded.

NOTE J—COMMITMENTS AND CONTINGENCIES

General Commitments

The Company has entered into various commitments and operating agreements related to development and production of certain oil and gas properties. It is management's belief that such commitments, as stated below, will be met without significant adverse impact to the Company's financial position or results of operations.

Leases

The Company leases corporate office space in Denver, Colorado on a month to month status. The Company leases oil and gas administrative offices located in Dallas, Texas which expires in April, 2022. The Company leases field office space in Rawlins, Wyoming which is on a month to month status. The Company leases office space in Long Beach, California which expires in November 2018. The Company leases office space in Tunkhannock, Pennsylvania which expires in August 2019. The Company leases office space in Casper, Wyoming on a month to month status.

Future minimum annual rental payments, which are subject to escalation and include utility charges as of December 31, 2016, are as follows:

	(in thousands)
Year ending December 31:	
2017	$ 349
2018	438
2019	384
2020	393
2021	401
Thereafter	134
	$ 2,099

Rent expense under these leases was approximately $0.1 million for the three months ended December 31, 2016 (Successor), $0.8 million for the nine months ended September 30, 2016 (Predecessor) and $1.1 million for the year ended December 31, 2015 (Predecessor).

Transportation Fee

Contracts assumed related to the Marcellus assets stipulated that the Company pay a fixed monthly amount of $1,241,000 for transportation of gas through the interstate pipeline, up to 120,000 dekatherms per day for a term ending in July 2022 (67 months remain on the contract). If the Company exceeds 120,000 dekatherms per day, the agreement states that a monthly fee of $0.34 per dekatherm over the contractually stipulated amount should be paid. Following the emergence from bankruptcy in October 2016, the commitment was reduced to 90,000 dekatherms per day for the next 36 months of the contract. Warren accounts for the aforementioned gathering and transportation fees on the Consolidated Statements of Operations within the lease operating expenses and taxes line item, as incurred. No overage fees have been included in the calculation of transportation fees.

Long-term debt and interest obligations

See Note D – Debt for additional information. Additionally, the outstanding principal balance of $140.3 million is due May 2022.

Asset Retirement Obligations

See Note A – Organization and Accounting Policies for additional information.

Bankruptcy Claims

Associated with the Company's filing and emergence from the Chapter II Cases, creditors have filed claims against the Company. The claims reconciliation process is ongoing and the estimated liability has not been finalized. The process includes review of the underlying claim filed against the Company and a reconciliation against the debtor's books and records.

The Company has estimated the liabilities associated with these claims at $1.5 million. This liability is included as a current liability in the consolidated financial statements at December 31, 2016.

NOTE K—OIL AND GAS INFORMATION

Costs related to the oil and gas activities of the Company were incurred as follows for the years ended December 31:

	Successor 2016	Predecessor 2015
	(in thousands)	
Property acquisition—unproved	$ —	$ —
Property acquisition—proved	—	18,626
Exploration costs	—	3
Development costs	5,052	17,359
	$ 5,052	$ 35,988

Asset retirement cost included in oil and gas property costs increased by approximately $0.6 million in 2016 and $0.1 million in 2015.

The Company had the following aggregate capitalized costs relating to the Company's oil and gas activities at December 31:

	Successor 2016	Predecessor 2015
	(in thousands)	
Unproved oil and gas properties	$ —	$ 14,658
Proved oil and gas properties	222,655	1,125,297
	222,655	1,139,955
Less accumulated depreciation, depletion and impairment expense	(154,292)	(977,270)
	$ 68,363	$ 162,685

The following table sets forth the Company's results of operations from oil and natural gas producing activities:

	Successor Three months ended December 30, 2016	Predecessor Nine months ended September 30, 2016	Predecessor Year ended December 31, 2015
		(in thousands)	
Revenues	$ 16,862	$ 39,712	$ 83,734
Production costs	(10,678)	(32,611)	(49,557)
Accretion of asset retirement obligation	(1,277)	(2,248)	(2,857)
Impairment	(145,117)	(87,094)	(562,151)
Depreciation, depletion, amortization	(9,175)	(15,128)	(59,729)
Loss from oil and gas producing activities	$ (149,385)	$ (97,369)	$ (590,560)

In the presentation above, no deduction has been made for indirect costs such as corporate overhead or interest expense. No income taxes are reflected above due to the Company's tax loss carryforwards.

The following is a summary of Warren's oil and gas properties not subject to amortization:

	Successor December 31, 2016	Predecessor December 31, 2015
	(in thousands)	
Acquisition costs	$ —	$ —
Exploration costs	—	—
Development costs(1)	—	365
Total oil and gas properties not subject to amortization	$ —	$ 365

(1) The Company's development costs primarily reflect investment in well cellars and facilities in its Wilmington oil field to facilitate the development of future oil wells. These costs will be allocated to future wells drilled, the majority of these wells are expected to be drilling during the next five to eight years.

NOTE L—OIL AND GAS RESERVE DATA (UNAUDITED)

The following estimates of proved reserve quantities and related standardized measure of discounted future net cash flows are estimates only, and do not purport to reflect realizable values or fair market values of the Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company's reserves are located in the United States.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods.

The standardized measure of discounted future net cash flows were computed by applying 12-month average prices for oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10%.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves provided by Netherland, Sewell & Associates, Inc. for 2016 and 2015:

	Oil (MBbls)	Gas (MMcf)	Equivalent Units (MBoe)
Proved reserves:			
Balance at December 31, 2014 (Predecessor)	16,794	327,328	71,348
Purchases of oil and gas reserves in place	—	—	—
Discoveries and extensions	69	4,654	845
Revisions of previous estimates	(2,944)	(140,218)	(26,314)
Production	(980)	(28,033)	(5,652)
Balance at December 31, 2015 (Predecessor)	12,939	163,731	40,227
Purchases of oil and gas reserves in place	—	—	—
Discoveries and extensions	—	—	—
Revisions of previous estimates	(7,413)	(17,124)	(10,267)
Production	(794)	(22,791)	(4,593)
Balance at December 31, 2016 (Successor)	4,732	123,816	25,368
Proved reserves at December 31, 2015 (Predecessor)			
Proved developed reserves	6,824	153,093	32,339
Proved undeveloped reserves	6,115	10,638	7,888
	12,939	163,731	40,227
Proved reserves at December 31, 2016 (Successor)			
Proved developed reserves	4,008	114,719	23,127
Proved undeveloped reserves	724	9,097	2,241
	4,732	123,816	25,368

On December 31, 2016, our total proved reserves were 25.4 MMBoe. Revisions decreased 2016 proved natural gas reserves and oil reserves by a net amount of 16.9 Bcf and 7.4 MMbbls as described below:

Wyoming – Lower gas prices coupled with increased marketing differentials resulted in a 53% drop in total proved reserves, comprised of a 10% decrease in proved developed producing reserves, 20% in proved developed non-producing and a 100% drop in the proved undeveloped category. The total value of the proved reserves (PV10%) decreased by $7.4 million from $15.4 million to $8.0 million.

Pennsylvania – Although the gas pricing used to generate the 2016 reserves was lower than 2015 pricing, marketing differentials decreased significantly resulting in a 17% increase in total proved reserves compared with 2015, virtually all realized in the proved developed producing category. The total value of the proved reserves (PV10%) increase by $12.6 million from a negative $5.6 million to $7.0 million.

California – A significant drop in SEC oil prices for 2016 resulted in a decrease of 58% to the total proved reserves. This decrease was comprised of a 33% decrease in proved developed producing reserves, a 25% decrease in proved developed non-producing reserves and an 88% decrease in proved undeveloped reserves. A significant portion of the reduction in proved undeveloped reserves is attributable to the SEC "5 year rule"; these reserves will be returned to the reserve report in the following year, subject to pricing. The total value of the proved reserves (PV10%) decreased by $73.0 million from $85.9 million to $12.9 million, mainly due to pricing and the SEC "5 year rule".

At December 31, 2015, our proved reserves were 40.2 MMBoe, all of which are scheduled to be drilled within five years of initial disclosure. Undeveloped reserves transferred to developed reserves were 0.8 MMBoe for the year ended December 31, 2015 and capital costs incurred to convert these proved undeveloped reserves were $12.9 million. Revisions decreased 2015 proved natural gas reserves and oil reserves by a net amount of 140 Bcf and 2.9 MMbbls, of which for natural gas 124 Bcf was due to pricing, 16 Bcf due to performance, and for oil 2.2 MMBbl was due to pricing and 0.7 MMBbl was due to performance. In 2015, total oil extensions and discoveries of 0.07 MMbbls resulted from the Company's drilling and completion activities in the Wilmington Townlot and North Wilmington Units in California. In 2015, total gas extensions and discoveries of 4.7 Bcf were from drilling activities in the Marcellus.

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

	Successor 2016	Predecessor 2015
Future cash inflows	$ 354,611	$ 862,751
Future production costs and taxes	(264,246)	(503,702)
Future development costs(1)	(66,605)	(180,790)
Future income tax expenses	—	—
Net future cash flows	23,760	178,259
Discounted at 10% for estimated timing of cash flows	4,595	(82,236)
Standardized measure of discounted future net cash flows	$ 28,355	$ 96,023

(1) Includes future estimated asset retirement obligations of $53.6 million in 2016 and $55.8 million in 2015.

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

	Successor 2016	Predecessor 2015
Sales, net of production costs and taxes	$ (13,286)	$ (34,176)
Discoveries and extensions	—	2,540
Purchases of reserves in place	—	—
Changes in prices and production costs	(108,350)	(342,650)
Revisions of quantity estimates	(51,108)	(202,716)
Development costs incurred	1,807	12,869
Net changes in development costs	74,142	131,919
Interest factor—accretion of discount	12,632	55,506
Net change in income taxes	—	(54,059)
Changes in production rates (timing) and other	16,495	(28,277)
Net (decrease) increase	(67,668)	(459,044)
Balance at beginning of year	96,023	555,067
Balance at end of year	$ 28,355	$ 96,023

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average prices for 2016 and 2015 along with estimates of the operating costs, production taxes and future development and abandonment costs (less salvage value) necessary to produce such reserves. The prices used at December 31, 2016 and 2015 were $33.39 and $42.81 per Bbl and $1.59, $1.74 per Mcf, respectively. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Operating costs and production taxes are estimated based on current costs with respect to producing oil and natural gas properties. Future development costs including abandonment costs are based on the best estimate of such costs assuming current economic and operating conditions. The future cash flows estimated to be spent to develop the Company's portion of proved undeveloped and proved developed non-producing properties through December 31, 2021 is $25.2 million.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved, less applicable carryforwards, for both regular and alternative minimum tax.

The future net revenue information assumes no escalation of costs or prices, except for oil and natural gas sales made under terms of contracts which include fixed and determinable escalation. Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

Table of Contents

Index to Financial Statements

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.

WARREN RESOURCES, INC.

By: /s/ JAMES A. WATT
James A. Watt
President and Chief Executive Officer

By: /s/ FRANK T. SMITH, JR.
Frank T. Smith, Jr.
Executive Vice President and Chief Financial Officer

By: /s/ ROMY M. MASSEY
Romy M. Massey
Vice President and Chief Accounting Officer

Dated: April 7, 2017

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 (Principal Function)	Date
/s/ JAMES A. WATT James A. Watt	Chairman of the Board of Directors, President and Chief Executive Officer (Principal Executive Officer)	April 7, 2017
/s/ FRANK T. SMITH, JR. Frank T. Smith, Jr.	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	April 7, 2017
/s/ ROMY M. MASSEY Romy M. Massey	Vice President and Chief Accounting Officer	April 7, 2017
/s/ ADAM LEIGHT Adam Leight	Director	April 7, 2017
/s/ DUANE KING Duane King	Director	April 7, 2017
/s/ YIXIAO LIU Yixiao Liu	Director	April 7, 2017
/s/ EUGENE DAVIS Eugene Davis	Director	April 7, 2017

Warren Resources, Inc. and Subsidiaries
WARREN RESOURCES, INC.
FORM 10-K
December 31, 2016

INDEX TO EXHIBITS

Exhibit No.	Description
2.1(40)	Purchase and Sale Agreement, dated as of July 6, 2014, by and among Citrus Energy Appalachia, LLC, TLK Energy LLC and Troy Energy Investments, LLC, as Seller, and Warren Resources, Inc., as Buyer, and joined in for certain limited purposes by Citrus Energy Corporation
2.2(41)	First Amendment and Waiver to Purchase and Sale Agreement, dated as of August 11, 2014, by and among Citrus Energy Appalachia, LLC, TLK Energy LLC and Troy Energy Investments, LLC, as Seller, and Warren Resources, Inc., as Buyer, and joined in for certain limited purposes by Citrus Energy Corporation
2.3(80)	Order Confirming the Debtor's Plan of Reorganization
3.1(17)	Certificate of Incorporation of Warren Resources, Inc., filed October 5, 2016 (Delaware)
3.2(14)	Bylaws of Warren Resources, Inc., dated October 5, 2016
3.3(10)	Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($.0001 Par Value)) (Maryland)
3.4(11)	Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.5(12)	Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland)
3.6(13)	Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland)
3.7(34)	Articles of Amendment to the Articles of Incorporation of Registrant
4.1(18)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(6)	Registration Rights Agreement made as of December 12, 2002, by and between Warren Resources and the Investors in the Series A 8% Cumulative Convertible Preferred Stock
4.3(43)	Indenture, dated as of August 11, 2014, by and between Warren Resources, Inc., Certain Subsidiaries of Warren Resources, Inc., as Guarantors and U.S. Bank National Association, as Trustee
4.4(45)	Form of Note (included in Exhibit 4.3)
4.5(42)	Registration Rights Agreement made as of August 11, 2014, by and between Warren Resources and the Purchasers of Common Stock
4.7(61)	Registration Rights Agreement, dated as of October 22, 2015, between Warren Resources, Inc. and the holders named therein
4.8(81)	Stockholders Agreement, dated as of October 5, 2016
4.9(82)	Plan Warrant Agreement, dated as of October 5, 2016
10.1(1)*	2000 Equity Incentive Plan for Warren E&P Subsidiary
10.2(2)*	Amendment to 2000 Stock Incentive Plan for Warren E&P Subsidiary
10.3(3)*	2001 Stock Incentive Plan
10.4(4)*	2001 Key Employee Stock Incentive Plan
10.5(5)*	Form of Indemnification Agreement
10.6(7)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.7(8)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.

Exhibit No.	Description
10.8(15)	Purchase and Sale Agreement dated November 24, 2004 by and among Warren Resources of California, Inc., Magness Petroleum Company and Next Generation Investments, LLC
10.9(16)	Settlement Agreement and Release dated November 24, 2004 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc., Warren Development Corp. and Magness Petroleum Company
10.10(19)	Asset Purchase Agreement dated December 9, 2005 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc. and Global Oil Production, LLC and Wilmington Management, LLC
10.11(20)	Form of Change in Control Agreement, dated as of May 9, 2009, between Warren Resources, Inc. and certain employees of Warren Resources, Inc.
10.12(21)*	2010 Stock Incentive Plan
10.13(24)	Second Amended and Restated Credit Agreement dated as of December 15, 2011 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Bank of Montreal, as Administrative Agent, as a Lender and the additional Lenders party thereto
10.14(22)	Coalbed Natural Gas (CBNG) Unit Agreement for the Development and Operation of the Spyglass Hill (CBNG) Unit area. Count of Carbon, State of Wyoming, dated February 26, 2011, by and between the parties identified therein
10.15(23)	Unit Operating Agreement Spyglass Hill (CBNG) Unit Area, dated February 26, 2011, by and among the parties identified therein
10.16(25)	Assignment and Bill of Sale (Spyglass Hill Unit) between Anadarko E&P Company, L.P. and Warren Resources, Inc. dated October 9, 2012
10.17(26)	Assignment and Bill of Sale (Catalina Unit) between Anadarko E&P Company, L.P. and Warren Resources, Inc. dated October 9, 2012
10.18(27)	Conveyance, Assignment and Bill of Sale between WGR Asset Holding Company LLC and Warren Energy Services, LLC dated October 9, 2012 for Midstream Assets
10.19(28)*	Amendment to 2010 Stock Incentive Plan
10.20(29)*	Executive Employment Agreement with Philip A. Epstein dated December 5, 2012
10.21(30)*	Employment Agreement with Timothy A. Larkin effective July 15, 2013
10.22(31)*	Employment Agreement with David E. Fleming effective July 15, 2013
10.23(32)*	Warren Resources, Inc. Severance Plan
10.25(35)*	Form of Incentive Stock Option Award Agreement
10.26(36)*	Form of Chief Executive Officer Incentive Stock Option Award Agreement
10.27(37)*	Form of Restricted Stock Unit Agreement
10.29(39)	Consulting Services Agreement, dated as of July 9, 2014, between Warren Resources, Inc. and Marc Rowland
10.30(46)	Purchase Agreement, dated as of August 6, 2014, by and among Warren Resources, Inc., as Seller, and BMO Capital Markets Corp., Jefferies LLC, Wells Fargo Securities, LLC, Capital One Securities, Inc., U.S. Bancorp Investments, Inc., BOSC, Inc., Comerica Securities, Inc., KeyBanc Capital Markets Inc., and Santander Investment Securities Inc., collectively as Sellers, and Warren E&P, Inc., Warren Resources of California, Inc., and Warren Marcellus LLC, as Guarantors

Exhibit No.	Description
10.33(49)*	Offer Letter, dated December 23, 2014, by and between Warren Resources Inc. and Lance Peterson
10.34(50)*	Restricted Stock Award Agreement, dated December 23, 2014, by and between Warren Resources Inc. and Lance Peterson
10.35(51)	Separation and General Release Agreement, dated December 31, 2014, by and between Warren Resources Inc. and Philip A. Epstein
10.36(52)*	Warren Resources, Inc. Executive Severance Plan
10.37(53)*	Form of Change in Control Agreement by and between Warren Resources, Inc. and each of Saema Somalya and Jeffrey Keeler
10.38(54)*	Offer Letter, dated December 24, 2013 and effective February 16, 2014, between Warren Resources, Inc. and Saema Somalya
10.39(55)*	Offer Letter, dated December 3, 2013 and effective January 8, 2014, between Warren Resources, Inc. and Jeffrey Keeler
10.40(56)	Credit Agreement dated as of May 22, 2015, among Warren Resources, Inc., as Borrower, Wilmington Trust, National Association, as Administrative Agent, the lenders party thereto, with GSO Capital Partners LP, as Sole Lead Arranger and Sole Bookrunner
10.41(57)	Second Amendment to the Warren Resources, Inc. 2010 Stock Incentive Plan
10.42(58)	Retention Agreement with Stewart Skelly dated October 15, 2015
10.43(59)	Retention Agreement with Saema Somalya dated October 15, 2015
10.44(60)	Retention Agreement with Jeffrey Keeler dated October 15, 2015
10.45(62)	Second Lien Credit Agreement, dated as of October 22, 2015, among Warren Resources, Inc., as Borrower, Cortland Capital Market Services, LLC, as Administrative Agent, and the lenders party thereto
10.46(63)	Amendment No. 1 to Credit Agreement, dated as of October 22, 2015, among Warren Resources, Inc., as Borrower, Wilmington Trust, National Association, as Administrative Agent, and the lenders party thereto
10.47(64)	Retention Agreement with Brian Gelman dated November 4, 2015
10.48(65)*	Offer of Employment to James A. Watt dated November 13, 2015
10.49(66)*	Offer of Employment to Frank T. Smith dated November 25, 2015
10.50(67)	First Amended and Restated Executive Severance Plan
10.51(68)	Consulting Services Agreement with Jeffrey Keeler, effective as of January 1, 2016
10.52(69)	Consulting Services Agreement with Somalya Law PLLC, effective as of January 5, 2016
10.53(70)	Separation Agreement with Jeffrey Keeler, dated December 28, 2015
10.54(71)	Separation Agreement with Saema Somalya, dated December 31, 2015
10.55(72)	Separation Agreement with Stewart Skelly, dated December 29, 2015
10.56(73)	First Amendment to the Separation Agreement and General Release with Stewart Skelly, dated February 8, 2016
10.57(74)	Consulting Services Agreement with Brian Gelman, dated February 16, 2016

Exhibit No.	Description
10.58(75)	Separation and Release Agreement with Brian Gelman, dated February 16, 2016
10.59(76)*	Offer of Employment to John R. Powers dated December 1, 2015
10.60(77)	Restructuring Support Agreement, dated June 2, 2016, by and among Warren Resources, Inc., certain of its subsidiaries, GSO Capital Partners LP on behalf of itself and on behalf of certain funds and accounts it manages, advises or sub-advises named as signatories therein, and each beneficial holder (or investment manager or advisor therefor) of the 9.0% Senior Notes due 2022 issued by Warren Resources, Inc. identified on the signature pages thereto
10.61(78)	Amended and Restated Restructuring Support Agreement, dated July 11, 2016, by and among Warren Resources, Inc., certain of its subsidiaries, GSO Capital Partners LP on behalf of itself and on behalf of certain funds and accounts it manages, advises or sub-advises named as signatories therein, Claren Road Credit Master Fund, Ltd. and Claren Road Credit Opportunities Master Fund, Ltd., and each beneficial holder (or investment manager or advisor therefor) of the 9.0% Senior Notes due 2022 issued by Warren Resources, Inc. identified on the signature pages thereto.
10.62(83)	Credit Agreement, dated as of October 5, 2016, by and among the Company, Wilmington Trust, National Association, as Administrative Agent, and the lenders from time to time a party thereto
10.63(84)*	Employment Agreement, by and between the Company and James A. Watt
10.64(85)*	Employment Agreement, by and between the Company and Frank T. Smith, Jr
10.65(86)	Warren Resources, Inc. 2016 Equity Incentive Plan
10.66(87)	Form of Restricted Stock Award Agreement
10.67(88)	Form of Stock Option Award Agreement
10.68(89)	Form of Restricted Stock Unit Award Agreement
10.69(90)	Form of Stock Appreciation Right Award Agreement
10.70(91)	Form of Indemnification Agreement
10.71(92)*	Offer Letter of Gregory J. Fox
10.72(93)*	Offer Letter of Romy M. Massey
14.1(9)	Code of Ethics for Senior Financial Officers
16.1(79)	Letter dated August 30, 2016 from Grant Thornton LLP to the Securities and Exchange Commission regarding the change in certifying accountant.
21.1†	Subsidiaries of the Registrant
23.2†	Consent of Netherland, Sewell & Associates, Inc.
31.1†	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2†	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32†	Certification of CEO and CFO pursuant to Section 1350
99.1†	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineer
101**	The following materials from the Warren Resources, Inc. Annual Report on Form 10-K for the year ended December 31, 2011 (and related periods), formatted in XBRL (eXtensible Business Reporting Language) include (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Stockholders' Equity and Comprehensive Income, (iv) the Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements

† Filed herewith

* Denotes a management contract or compensatory plan or arrangement

** Users of this data are advised pursuant to Rule 401 of Regulations S-T that the financial information contained in the XBRL- Related Documents is unaudited. Furthermore, users of this data are advised in accordance with Rule 406T of Regulations S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these Sections

(1) Incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001

(2) Incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001

(3) Incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001

(4) Incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001

(5) Incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001

(6) Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 17, 2002

(7) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 24, 2002

(8) Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 24, 2002

(9) Incorporated by reference to Exhibit 14 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002, Commission File No. 000-33275, filed on March 31, 2003

(10) Incorporated by reference to Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, Commission File No. 000-33275, filed on August 16, 2004

(11) Incorporated by reference to Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, Commission File No. 000-33275, filed on August 16, 2004

(12) Incorporated by reference to Exhibit 3.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, Commission File No. 000-33275, filed on August 16, 2004

(13) Incorporated by reference to Exhibit 3.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, Commission File No. 000-33275, filed on August 16, 2004

(14) Incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8 K, Commission File No. 000 33275, filed on October 12, 2016

(15) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on November 30, 2004

(16) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on November 30, 2004

(17) Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016

(18) Incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 000-33275, filed on March 17, 2005

(19) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 14, 2005

(20) Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed August 5, 2009

(21) Incorporated by reference to Exhibit A to the Company's Definitive Proxy Statement on Form DEF 14-A filed on April 8, 2010

(22) Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed November 8, 2011

(23) Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed November 8, 2011

(24) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 16, 2011

(25) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed October 15, 2012

(26) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed October 15, 2012

(27) Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed October 15, 2012

(28) Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed November 7, 2012
(29) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 7, 2012
(30) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 20, 2013
(31) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 20, 2013
(32) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed November 21, 2013
(33) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 17, 2013
(34) Incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Form DEF 14-A filed on April 24, 2014
(35) Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed May 7, 2014
(36) Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed May 7, 2014
(37) Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed May 7, 2014
(38) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed June 10, 2014
(39) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed July 10, 2014
(40) Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(41) Incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(42) Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(43) Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(44) Incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(45) Incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(46) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(47) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 12, 2014
(48) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 2, 2014
(49) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 24, 2014
(50) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 24, 2014
(51) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed January 2, 2015
(52) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on April 4, 2015
(53) Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed on May 7, 2015
(54) Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed on May 7, 2015
(55) Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed on May 7, 2015
(56) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on May 26, 2015
(57) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on June 8, 2015

(58) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 20, 2015
(59) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 20, 2015
(60) Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 20, 2015
(61) Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 22, 2015
(62) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 22, 2015
(63) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 22, 2015
(64) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on November 6, 2015
(65) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on November 16, 2015
(66) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on November 30, 2015
(67) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 9, 2015
(68) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on January 5, 2016
(69) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on January 5, 2016
(70) Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on January 5, 2016
(71) Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on January 5, 2016
(72) Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on January 5, 2016
(73) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on February 9, 2016
(74) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on February 18, 2016
(75) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on February 18, 2016
(76) Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on February 18, 2016
(77) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on June 2, 2016
(78) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on July 12, 2016
(79) Incorporated by reference to Exhibit 16.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on August 30, 2016
(80) Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on September 20, 2016
(81) Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(82) Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(83) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(84) Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(85) Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(86) Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(87) Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016

[Table of Contents](#)

[Index to Financial Statements](#)

(88) Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(89) Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(90) Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(91) Incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 12, 2016
(92) Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on October 20, 2016

Exhibit 21.1

Subsidiaries of Warren Resources, Inc.

Name	Jurisdiction of Formation
Warren E&P, Inc.	New Mexico
Warren Resources of California, Inc.	California
Warren Management Corp.	Delaware
Warren Energy Services, LLC	Delaware
Warren Marcellus LLC	Delaware

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Form 10-K of Warren Resources, Inc. to be filed on or about April 7, 2017, as well as in the Notes to the Consolidated Financial Statements included in such Form 10-K, of our summary reports dated February 21, 2017, February 5, 2016, and February 18, 2015, to the interest of Warren Resources, Inc. and its subsidiaries, relating to the estimated quantities of proved reserves of oil and gas and present values thereof, included in the annual reports on Form 10-K of Warren Resources, Inc. for the years ended December 31, 2016, December 31, 2015, and December 31, 2014, respectively. We further consent to the inclusion of our summary report dated February 21, 2017, as an Exhibit to Warren Resources, Inc.'s annual reports on Form 10-K for the year ended December 31, 2016.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
April 7, 2017

Exhibit 31.1

Certification

I, James A. Watt, certify that:

1. I have reviewed this annual report on Form 10-K of Warren Resources, 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: April 7, 2017

/s/ JAMES A. WATT
James A. Watt
Chief Executive Officer

Exhibit 31.2

Certification

I, Frank T. Smith, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Warren Resources, 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: April 7, 2017

/s/ FRANK T. SMITH, JR.

Frank T. Smith, Jr.
Executive Vice President and Chief Financial Officer

EXHIBIT 32

CERTIFICATION OF CEO AND CFO 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 Warren Resources, Inc. (the "Company") for the period ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we, James A. Watt, Chief Executive Officer and Frank T. Smith, Jr., Chief Financial Officer, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(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: April 7, 2017

/s/ James A. Watt
Name: James A. Watt
Title: Chief Executive Officer

/s/ Frank T. Smith, Jr.
Name: Frank T. Smith, Jr.
Title: Executive Vice President and Chief Financial Officer

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

February 21, 2017

Mr. James A. Watt
Warren Resources, Inc.
5420 LBJ Freeway, Suite 600
Dallas, Texas 75240

Dear Mr. Watt:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2016, to the Warren Resources, Inc. (Warren) interest in certain oil and gas properties located in California, New Mexico, Pennsylvania, Texas, and Wyoming. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Warren. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Warren's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Warren interest in these properties, as of December 31, 2016, to be:

	Net Reserves		Future Net Revenue(1) (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	3,061.3	105,675.4	-3,314.7	9,104.0
Proved Developed Non-Producing	946.3	9,043.4	18,345.0	12,393.3
Proved Undeveloped	724.3	9,097.3	8,730.0	6,857.6
Total Proved	4,731.8	123,816.1	23,760.3	28,355.0

Totals may not add because of rounding.

(1) Future net revenue is after deducting estimated abandonment costs.

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

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

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

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Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2016. For oil volumes, the average West Texas Intermediate posted price of $39.25 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.481 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $33.39 per barrel of oil and $1.588 per MCF of gas.

Operating costs used in this report are based on operating expense records of Warren. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and Warren's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. For the Pennsylvania properties, Warren has a firm transportation contract in place with UGI Energy Services. An economic projection is included in the proved developed producing category to account for the fees associated with this transportation contract. For all other areas, we have made no investigation of any firm transportation contracts that may be in place and no adjustments have been made to our estimates of future revenue to account for such contracts. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

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

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

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Warren interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Warren receiving its net revenue interest share of estimated future gross production.

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

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Warren, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. C. Ashley Smith, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

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

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

By: /s/ C. Ashley Smith
C. Ashley Smith, P.E. 100560
Vice President

Date Signed: February 21, 2017

By: /s/ Shane M. Howell
Shane M. Howell, P.G. 11276
Vice President

Date Signed: February 21, 2017

CAS:SMD

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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

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

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

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

> *Supplemental definitions from the 2007 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

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

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

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

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

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

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

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

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

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

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

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

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

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

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

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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

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

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

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

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

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

(20) *Production costs.*

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

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

(E) Severance taxes.

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

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

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

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

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

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

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

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

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

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

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

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

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

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

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

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

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