CENTENNIAL
RESOURCE DEVELOPMENT, INC

2016 ANNUAL REPORT

STRATEGY MEETS EXECUTION

LETTER TO SHAREHOLDERS

Centennial Resource Development, Inc. is a brand new public E&P company, and our initial letter to shareholders will outline some of the principles and strategic vision of the company. We hope this will provide you, the shareholder, a broader sense of perspective regarding our management philosophy. Some of our fundamental beliefs and objectives are as follows:

1. Our goal is to achieve one of the best long-term equity performances in the U.S. independent E&P sector. Our 2016 equity performance was +97%, so we are off to a good start. We intend to continue that performance trend by generating rapid oil production growth from approximately 5,800 barrels of oil per day in 2016 to 50,000 barrels of oil per day in 2020. This, in turn, will generate concomitant cash flow and earnings increases, which should be a significant stock price driver.
2. We believe oil prices will modestly increase in the next three to four years and have positioned our assets in an oil-rich area in West Texas. We believe the global oil supply / demand picture will tighten and that incremental U.S. shale oil supplies will be required to meet global energy demand.
3. We are more interested in quality than size. We do not intend to become the biggest company in the Delaware Basin, but our goal is to become the best company in the Basin.
4. We will avoid moderate or high debt loads. In a commodity business, we believe even moderate debt loads should be avoided, and we intend to run Centennial with a light level of leverage.
5. We believe the highest reinvestment rates of return are achieved through technical excellence, and we expect to become one of the technical leaders in shale oil extraction.
6. Unlike many public E&P companies, we believe that financial returns matter, and in a rising oil price environment, we expect to generate positive ROE's and ROCE's.
7. We believe in alignment between management compensation and share price performance.

In closing, we believe that Centennial is well-positioned to create significant value for our shareholders, and we look forward to growing with you in the future.

Sincerely,

Mark G. Papa
President, Chief Executive Officer and
Chairman of the Board

2016 ANNUAL REPORT

FORM 10-K

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

FORM 10-K

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2016

or

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-37697

CENTENNIAL RESOURCE DEVELOPMENT, INC.
(Exact name of registrant as specified in its charter)

Delaware	**47-5381253**
(State of Incorporation)	(I.R.S. Employer Identification No.)

1401 Seventeenth Street, Suite 1000, Denver, Colorado 80202
(Address of principal executive offices including zip code)

(Registrant's telephone number, including area code): (720) 441-5515

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

Title of each class	Name of each exchange on which registered
Class A Common Stock, par value $0.0001 per share	The NASDAQ Capital Market LLC
Warrants, each exercisable for one share of Class A Common Stock	The NASDAQ Capital Market LLC

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 the filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant as of June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $488,726,000 based on the closing price of the shares of common stock on that date.

As of March 7, 2017, there were 201,882,082 shares of Class A Common Stock, par value $0.0001 per share, no shares of Class B Common Stock, par value $0.0001 per share, and 19,155,921 shares of Class C Common Stock, par value $0.0001 per share, outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this Annual Report on Form 10-K, which are commonly used in the oil and natural gas industry:

Bbl. One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

Bbl/d. One Bbl per day.

Bcf. One billion cubic feet of natural gas.

Boe. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. One Boe per day.

Btu. One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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

Development project. 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.

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

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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 natural gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

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

MBbl. One thousand barrels of crude oil, condensate or NGLs.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBbl. One million barrels of crude oil, condensate or NGLs.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NGLs. Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

NYMEX. The New York Mercantile Exchange.

Operator. The individual or company responsible for the development and/or production of an oil or natural gas well or lease.

Proved developed reserves. Reserves that can be expected to be recovered through (i) existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (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.

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

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

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

Reserves. Estimated remaining quantities of oil and natural 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 natural gas or related substances to market and all permits and financing required to implement the project. 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).

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

Spot market price. The cash market price without reduction for expected quality, transportation and demand adjustments.

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

Working interest. The right granted to the lessee of a property to develop and produce and own natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

WTI. West Texas Intermediate.

GLOSSARY OF CERTAIN OTHER TERMS

The following are definitions of certain other terms that are used in this Annual Report on Form 10-K:

Business Combination. The acquisition of approximately 89% of the outstanding membership interests in CRP from the Centennial Contributors, which closed on October 11, 2016, and the other transactions contemplated by the Contribution Agreement.

Business Combination Private Placements. The issuance and sale in private placements of (i) 81,005,000 shares of Class A Common Stock to Riverstone Centennial Holdings, L.P. and (ii) 20,000,000 shares of Class A Common Stock to certain other investors, which closed simultaneously with the consummation of the Business Combination.

Celero. Celero Energy Company, LP, a Delaware limited partnership.

Centennial Contributors. CRD, NGP Follow-On and Celero, collectively.

The Company, We, Our or Us. (a) Centennial Resource Development, Inc. and its subsidiaries, including CRP, following the closing of the Business Combination and (b) Silver Run Acquisition Corporation prior to the closing of the Business Combination.

Class A Common Stock. Our Class A Common Stock, par value $0.0001 per share.

Class B Common Stock. Our Class B Common Stock, par value $0.0001 per share.

Class C Common Stock. Our Class C Common Stock, par value $0.0001 per share, which were issued to the Centennial Contributors in connection with the Business Combination.

Contribution Agreement. The Contribution Agreement, dated as of July 6, 2016, among the Centennial Contributors, CRP and NewCo, as amended by Amendment No. 1 thereto, dated as of July 29, 2016, and the Joinder Agreement, dated as of October 7, 2016, by the Company.

CRD. Centennial Resource Development, LLC, a Delaware limited liability company.

CRP. Centennial Resource Production, LLC, a Delaware limited liability company.

CRP Common Units. The units representing common membership interests in CRP.

Founder Shares. Shares of our Class B Common Stock purchased by our Sponsor in a private placement prior to our IPO, which were converted into shares of Class A Common Stock on a one-for-one basis in connection with the closing of the Business Combination.

Initial Stockholders. Holders of our founder shares prior to our IPO, including our Sponsor and our independent directors prior to the Business Combination.

IPO. Our initial public offering of units, which closed on February 29, 2016.

NewCo. New Centennial, LLC, a Delaware limited liability company controlled by affiliates of Riverstone.

NGP Follow-On. NGP Centennial Follow-On LLC, a Delaware limited liability company.

Private Placement Warrants. Our 8,000,000 outstanding warrants, which were purchased by our Sponsor in a private placement simultaneously with the closing of our IPO.

Public Warrants. Our 16,666,643 outstanding warrants, which were sold as part of the Units in our IPO.

Riverstone. Riverstone Investment Group LLC and its affiliates, including our Sponsor, collectively.

Riverstone Purchasers. Riverstone VI Centennial QB Holdings, L.P., Riverstone Non-ECI USRPI AIV, L.P. and REL US Centennial Holdings, LLC, which are affiliates of Riverstone.

Series B Preferred Stock. Our Series B Preferred Stock, par value $0.0001 per share.

Series B Preferred Units. Series B Preferred Units of CRP which, by their terms, convert to CRP Common Units upon the conversion of the Series B Preferred Stock.

Silverback Acquisition. Our acquisition of leasehold interests and related upstream assets in Reeves County, Texas from Silverback Exploration, LLC and Silverback Operating, LLC, which closed on December 28, 2016.

Silverback Acquisition Private Placements. The issuance and sale in private placements of (i) 3,473,590 shares of Class A Common Stock and 104,400 shares of Series B Preferred Stock to the Riverstone Purchasers and (ii) 33,012,380 shares of our

Class A Common Stock to certain other investors, which closed simultaneously with the consummation of the Silverback Acquisition.

Sponsor. Our sponsor, Silver Run Sponsor, LLC, a Delaware limited liability company and an affiliate of Riverstone.

Units. Our units sold in our IPO, each of which consisted of one share of Class A Common Stock and one-third of one Public Warrant.

V*oting common stock*. Our Class A Common Stock and Class C Common Stock.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Throughout this Form 10-K, we make statements that may be deemed “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors in this annual report.

Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our drilling prospects, inventories, projects and programs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, liquidity and capital required for our development program;
- our realized oil, natural gas and natural gas liquids ("NGL") prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- our future drilling plans;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this prospectus that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks described under Part I, Item 1A. Risk Factors.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Form 10-K.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Corporate History

Centennial Resource Development, Inc. (the "Company," "Centennial," "we," "us," or "our") was originally incorporated in Delaware on November 4, 2015 as a special purpose acquisition company under the name Silver Run Acquisition Corporation for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving us and one or more businesses.

On February 29, 2016, we consummated our initial public offering of Units each consisting of one share of Class A Common Stock and one-third of one Public Warrant. On October 11, 2016, we consummated the acquisition of approximately 89% of the outstanding membership interests in Centennial Resource Production, LLC, a Delaware limited liability company ("CRP" and such acquisition, the "Business Combination").

CRP was formed in August 2012 by an affiliate of NGP Energy Capital Management, a family of energy-focused private equity investment funds, in connection with the acquisition of all of the oil and natural gas properties and certain other assets of Celero, which was formed in 2006 to focus on the development and acquisition of oil and natural gas properties in Texas and New Mexico, primarily in the Permian Basin in West Texas. Until the closing of the Business Combination, CRP operated as a privately-held independent oil and natural gas company.

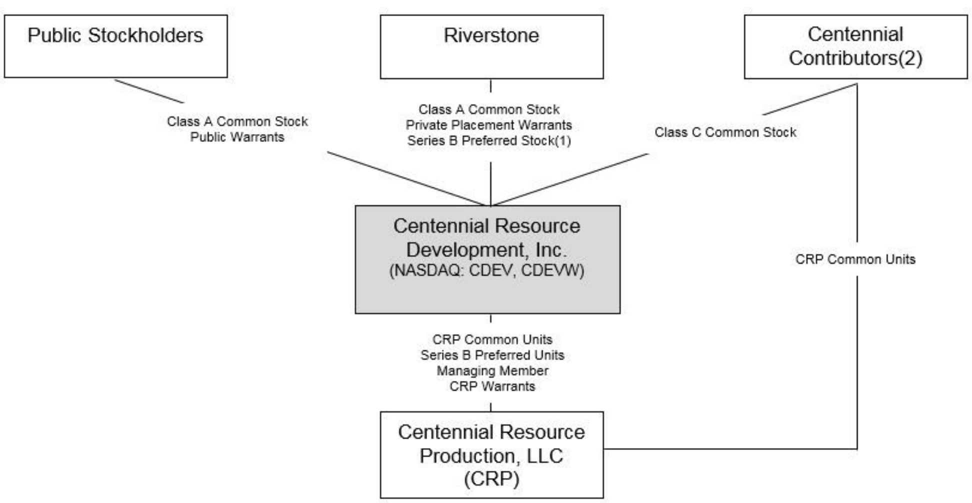
Our Class A Common Stock and Public Warrants trade on The NASDAQ Capital Market ("NASDAQ") under the ticker symbols "CDEV" and "CDEVW," respectively. The Units automatically separated into their component securities prior to or upon closing of the Business Combination and, as a result, no longer trade as a separate security.

Presentation of Financial and Operating Data

As a result of the Business Combination, we are the acquirer for accounting purposes, and CRP is the acquiree and accounting Predecessor. Our financial statement presentation distinguishes a "Predecessor" for CRP for periods prior to the Business Combination. We are the "Successor" for periods after the Business Combination, which includes consolidation of CRP subsequent to the Business Combination on October 11, 2016.

Organizational Structure

The following diagram illustrates the current ownership structure of the company:



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(1) The Company intends to hold a special meeting at which its stockholders will vote on the issuance of the Class A Common Shares underlying the shares of Series B Preferred Stock.

(2) CRD, one of the Centennial Contributors, also owns one share of our Series A Preferred Stock, par value $0.0001 per share (the "Series A Preferred Stock"), which does not have any voting rights (other than the right to nominate and elect one director to our board of directors) or rights with respect to dividends but is entitled to preferred distributions in liquidation in the amount of $0.0001 per share.

Our Business

Our only significant asset is our current ownership of an approximate 92% membership interest in CRP. We are an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. Our properties consist of large, contiguous acreage blocks in Reeves, Ward and Pecos counties in West Texas.

Our principal business objective is to increase shareholder value by building a premier development company focused on horizontal drilling in the Delaware Basin. We intend to grow our production and oil and natural gas reserves by developing our acreage in Ward and Reeves Counties with an increased focus on optimizing completions, improving drilling results and drilling extended laterals. We also intend to grow our production and reserves through acquisitions that meet our strategic and financial objectives.

Our Properties

As of December 31, 2016, our portfolio included 106 operated producing horizontal wells. The horizontal wells span an area approximately 45 miles long by 20 miles wide where we have established commercial production in five distinct zones: the 3rd Bone Spring Sandstone, Upper Wolfcamp A, Lower Wolfcamp A, Wolfcamp B and Wolfcamp C. As a result, we have broadly appraised this acreage across various geographic areas and stratigraphic zones, which we expect will allow us to efficiently develop our drilling inventory with a focus on maximizing returns to our stockholders. In addition, we believe this acreage may be prospective for the 2nd and 3rd Bone Spring shales and Avalon shale, where other operators have experienced drilling success near our acreage.

As of December 31, 2016, we have leased or acquired approximately 76,067 net acres, approximately 85% of which we operate. Our acreage is predominantly located in the southern portion of the Delaware Basin, where production and reserves typically contain a higher percentage of oil and natural gas liquids and a correspondingly lower percentage of natural gas compared to the northern area of the Delaware Basin. After temporarily suspending drilling activity at the end of March 2016 to preserve capital prior to the Business Combination, we added one horizontal rig in June 2016, a second horizontal rig in September 2016 and a third horizontal rig in October 2016. After closing the Silverback Acquisition on December 28, 2016, we had four rigs operating. During 2016, we placed ten gross operated horizontal wells on production. Our development drilling plan is comprised exclusively of horizontal drilling with an ongoing focus on optimizing completions, improving drilling results and managing costs.

Proved Oil and Gas Reserves

The table below presents information with respect to the estimates of our net proved reserves as of December 31, 2016 (Successor), December 31, 2015 (Predecessor) and December 31, 2014 (Predecessor). We engage Netherland, Sewell & Associates, Inc. ("NSAI") to prepare our estimated net proved reserves. Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. For oil and NGL volumes, the average West Texas Intermediate posted price for each year was adjusted for quality, transportation fees and a regional price differential. For gas volumes, the average Henry Hub spot price for each year was adjusted for energy content, transportation fees and a regional price differential. 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 $38.49 per barrel of oil, $14.59 per barrel of NGL and $0.98 per Mcf of gas as of December 31, 2016 (Successor), $41.85 per barrel of oil, $13.94 per barrel of NGL and $1.71 per Mcf of gas as of December 31, 2015 (Predecessor), and $84.94 per barrel of oil, $22.70 per barrel of NGL and $4.70 per Mcf of gas as of December 31, 2014 (Predecessor).

Reserve estimates are inherently imprecise and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. PV-10 shown in the following table is not intended to represent the current market value of our estimated proved reserves. The actual quantities and present value of our estimated proved reserves may be more or less than we have estimated. The following table should be read along with Part I, Item 1A. Risk Factors in this annual report.

The following table summarizes estimated proved reserves, PV-10, and standardized measure of discounted future cash flows as of December 31, 2016 (Successor), December 31, 2015 (Predecessor), and December 31, 2014 (Predecessor):

	Successor	Predecessor	
	December 31, 2016	December 31, 2015	December 31, 2014
Proved developed reserves:			
Oil (MBbls)	14,551	9,347	8,026
Natural gas (MMcf)	42,190	12,711	11,959
NGL (MBbls)	3,618	1,603	766
Total (MBoe)(1)	25,200	13,068	10,786
Proved undeveloped reserves:			
Oil (MBbls)	31,914	13,852	11,823
Natural gas (MMcf)	106,154	19,731	15,455
NGL (MBbls)	8,152	2,248	785
Total (MBoe)(1)	57,759	19,389	15,184
Total proved reserves:			
Oil (MBbls)(1)	46,466	23,199	19,850
Natural gas (MMcf)(1)	148,344	32,442	27,414
NGL (MBbls)(1)	11,770	3,851	1,551
Total (MBoe)(1)	82,959	32,457	25,970
Proved developed reserves %	30%	40%	42%
Proved undeveloped reserves %	70%	60%	58%
Reserve data (in millions):			
Proved developed PV-10	$ 242.1	$ 141.4	$ 299.2
Proved undeveloped PV-10	185.4	4.1	71.2
Total proved PV-10	$ 427.5	$ 145.5	$ 370.4
Standardized measure of discounted future net cash flows	$ 375.1	$ 135.1	$ 365.9

(1) Totals may not sum or calculate due to rounding.

Proved Undeveloped Reserves

As of December 31, 2016 (Successor), total estimated proved undeveloped reserves ("PUDs") were 31,914 MBbls of oil, 106,154 MMcf of natural gas and 8,152 MBbls of NGLs, for a total of 57,759 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2016 were primarily due to (i) an increase of approximately 14,773 MBoe attributable to extensions resulting from strategic drilling of wells delineating our acreage position; (ii) the conversion of approximately 2,112 MBoe from proved undeveloped into proved developed reserves; (iii) a revision in performance of approximately 2,488 MBoe due to improved results in completion techniques and adjustments of natural gas and NGL treatment through the gas plants; and (iv) an increase of 23,221 MBoe in proved undeveloped reserves mainly due to the Silverback Acquisition.

During 2016, we spent $22.9 million to convert PUDs to proved developed reserves.

All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking. As of December 31, 2016, 854 MBoe of our total proved reserves were classified as proved developed non-producing ("PDNP").

Preparation of Reserves Estimates

Evaluation and Review of Proved Reserves. Our historical proved reserve estimates as of December 31, 2016, 2015 and 2014 were prepared based on reports by NSAI. NSAI is a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Neil H. Little and Mr. Mike K. Norton. Mr. Little, a

Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. He graduated from Rice University in 2002 with a Bachelor of Science Degree in Chemical Engineering and from University of Houston in 2007 with a Master of Business Administration Degree. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441), has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Terry Sherban, our Vice President - Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with 37 years of reservoir and operations experience.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2016, 2015 and 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

Production

The following table sets forth information regarding net production of oil, natural gas and NGLs, and certain price and cost information for each of the periods indicated:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Production data:				
Oil (MBbls)	523	1,584	1,830	1,428
Natural gas (MMcf)	1,113	2,660	3,058	2,112
NGLs (MBbls)	96	253	331	235
Total (MBoe)	805	2,280	2,671	2,015
Average realized prices (excluding effect of hedges):				
Oil (per Bbl)	$ 46.49	$ 37.74	$ 42.43	$ 80.50
Natural gas (per Mcf)	3.10	2.27	2.60	4.58
NGL (per Bbl)	20.36	12.98	14.66	30.64
Per BOE	$ 36.92	$ 30.31	$ 33.87	$ 65.42
Production costs per Boe:				
Lease operating expenses	$ 4.40	$ 4.84	$ 7.93	$ 8.78
Severance and ad valorem taxes	2.03	1.62	1.88	3.41
Transportation, processing, gathering and other operating expenses	2.72	2.01	2.15	2.37
Contract termination and rig stacking	—	—	0.89	—

Productive Wells

As of December 31, 2016, we owned an approximate 67% average working interest in 199 gross (133 net) productive wells. Our wells are oil wells that produce associated liquids-rich natural gas. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

Acreage

The following table sets forth information as of December 31, 2016 relating to our leasehold acreage. Developed acreage consists of acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is defined as acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
10,800	10,000	113,158	66,067	123,958	76,067

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

The following table sets forth the gross and net undeveloped acreage, as of December 31, 2016, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates:

2017		2018		2019		2020		2021	
Gross	Net	Gross	Net	Gross	Net	Gross	Net(1)	Gross	Net(1)
19,942	12,440	23,748	10,420	16,528	12,071	—	102	—	30

(1) Expiring net acreage may be greater than expiring gross acreage when multiple undivided interests in the same gross acreage expire at different times.

Drilling Results

The following table sets forth the results of our drilling activity, as defined by wells placed on production, for the periods indicated. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Successor		Predecessor					
	October 11, 2016 through December 31, 2016		January 1, 2016 through October 10, 2016		Year Ended December 31,			
					2015		2014	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells:								
Productive(1)	5.0	2.5	10.0	7.0	16.0	12.4	36.0	26.8
Dry	—	—	—	—	—	—	—	—
	5.0	2.5	10.0	7.0	16.0	12.4	36.0	26.8
Exploratory Wells:								
Productive(1)	—	—	—	—	—	—	—	—
Dry	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—
Total	5.0	2.5	10.0	7.0	16.0	12.4	36.0	26.8

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and we believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this report.

Marketing and Customers

We market the majority of our production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our oil, natural gas and NGL production to purchasers at market prices. We sell all of our natural gas and NGLs under contracts with terms of greater than twelve months and all of our oil under contracts with terms of less than twelve months.

We normally sell production to a relatively small number of customers, as is customary in our business. For the year ended December 31, 2016, sales to Plains Marketing, LP ("Plains"), Shell Trading (US) Company, and Permian Transport and Trading accounted for 48%, 22%, and 11%, respectively, of the total revenue. For the years ended December 31, 2015 and December 31, 2014, we only had one major customer, Plains, which accounted for 64% and 78%, respectively, of total revenue. During these periods, no other purchaser accounted for 10% or more of our revenue. The loss of any of our major purchasers could materially and adversely affect our revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any major purchaser would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

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

Transportation

During the initial development of our fields, we consider all gathering and delivery infrastructure options in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The purchaser then transports the oil by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is generally transported by our gathering lines from the wellhead to a Central Delivery Point ("CDP") and then is gathered by third-party lines from these CDPs to a gas processing facility. At a small number of our wells, we own natural gas pipeline facilities that connect our wells to third-party natural gas gathering systems located in the vicinity of those wells.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Demand for oil and natural gas is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties as of December 31, 2016 generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80%.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the development and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, FERC and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Oil and Natural Gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in Texas, which regulates drilling and operating activities by, among other things, requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate 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 and the plugging and abandonment of wells. The laws of Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Sales and Transportation of Oil

Sales of oil, condensate and NGLs from our producing wells are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

Our sales of oil are affected by the availability, terms and conditions and cost of transportation services. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates the transportation in interstate commerce of crude oil, petroleum products, NGLs and other forms of liquid fuel under the Interstate Commerce Act.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. We rely on third-party pipelines systems to transport the majority of crude oil produced by ours wells. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

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

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA, and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the NGA, and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The EP Act of 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provided FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increased FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. On June 29, 2016, FERC issued an order (Order No. 826) increasing the maximum civil penalty amounts under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of $1,193,970 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful to: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

We are required to observe such anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. Should we violate the anti-market manipulation laws and regulations, it could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Natural gas gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts companies that provide natural gas gathering services from regulation by FERC as a "natural gas company" under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, or vice versa, and depending on the scope of that decision, our costs of getting gas to point-of-sale locations may increase. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

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

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

Regulation of Environmental and Occupational Safety and Health Matters

Our oil and natural gas development operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (“CERCLA”), also known as the “Superfund” law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and 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. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act (“RCRA”) and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies under RCRA’s less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, from time to time various environmental groups have challenged the EPA’s exemption of certain oil and gas wastes from RCRA. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we may generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease or operate numerous properties that have been used for oil and natural gas development and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into or near navigable waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the “Corps”). In September 2015, the EPA and the Corps issued new rules defining the scope of the EPA’s and the Corps’ jurisdiction under the Clean Water Act with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands. To the extent the rule expands the scope of the Clean Water Act’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of the Clean Water Act, and implementation of the rule has been stayed pending resolution of the court challenge. Obtaining permits has the potential to delay the development of oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations, and further believe we are in substantial compliance with the terms thereof. We are currently undertaking a review of recently acquired oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 (“OPA”), which amends and augments the oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA has adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. More recently, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of GHG Emissions

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet “best available control technology” standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. The EPA has also announced that it intends to impose methane emission standards for existing sources as well but, to date, has not yet issued a proposal. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Most recently, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, which requires member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. The agreement was signed in April 2016, and entered into force in November 2016. The United States is one of over 70 nations having ratified or otherwise consented to be bound by the agreement. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and also finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming struck down this rule. The BLM has appealed this decision. The appeal remains pending. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the

SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

ESA and Migratory Birds

The Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

We have not experienced any material adverse effect from compliance with environmental requirements; however, there is no assurance that this will continue. We have not incurred any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2016, nor do we expect to incur any such expenditures in 2017.

Related Insurance

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

Employees

As of December 31, 2016, we had 57 full-time employees. We hire independent contractors on an as needed basis, and have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Offices

Our principal executive offices are located at 1401 Seventeenth Street, Suite 1000, Denver, Colorado 80202, and our telephone number is (720) 441-5515. We also lease office space in Midland, Texas, Sugar Land, Texas and Pecos, Texas.

Available Information

Our internet website address is www.cdevinc.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

The public may also read and copy materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, DC 20549. You can obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at www.sec.gov.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following risks and uncertainties, together with other information set forth in this annual report on Form 10-K, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.

Our only significant asset is our current ownership of an approximate 92% membership interest in CRP. Distributions from CRP may not be sufficient to allow us to pay any dividends on our Class A Common Stock or satisfy our other financial obligations.

We have no direct operations and no significant assets other than our current ownership of an approximate 92% membership interest in CRP. We will depend on CRP for distributions, loans and other payments to generate the funds necessary to meet our financial obligations or to pay any dividends with respect to our Class A Common Stock. Subject to certain restrictions, CRP generally will be required to (i) make pro rata distributions to its members, including us, in an amount at least sufficient to allow us to pay our taxes and (ii) reimburse us for certain corporate and other overhead expenses. However, legal and contractual restrictions in agreements governing future indebtedness of CRP, as well as the financial condition and operating requirements of CRP may limit our ability to obtain cash from CRP. The earnings from, or other available assets of, CRP may not be sufficient to pay dividends or make distributions or loans to enable us to pay any dividends on our Class A Common Stock or satisfy our other financial obligations.

Oil, natural gas and NGL prices are volatile. A sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil, natural gas and NGLs production heavily influence our revenue, profitability, access to capital, future rate of growth and carrying value of our properties. Oil, natural gas and NGLs are commodities, and their prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, natural gas and NGLs and market uncertainty. Historically, oil, natural gas and NGL prices have been volatile. For example, during the period from January 1, 2014 through December 31, 2016, the WTI spot price for oil has declined from a high of $107.95 per Bbl on June 20, 2014 to $26.19 per Bbl on February 11, 2016, and the Henry Hub spot price for natural gas has declined from a high of $8.15 per MMBtu on February 10, 2014 to a low of $1.49 per MMBtu on March 4, 2016. Likewise, NGLs, which are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, have suffered significant recent declines in realized prices. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control, which include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports of oil, natural gas and NGLs;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of the Organization of the Petroleum Exporting Countries ("OPEC"), its members and other state-controlled oil companies relating to oil price and production controls;
- the level of global exploration, development and production;
- the level of global inventories;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- expectations about future commodity prices; and

- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Compared to 2014, our realized oil price for 2015 fell 47% to $42.43 per barrel, and further decreased in 2016 to $39.91 per barrel. Similarly, our realized natural gas price for 2015 dropped 43% to $2.60 per Mcf and our realized price for NGLs declined 52% to $14.66 per barrel. In 2016, our realized price for natural gas was $2.52 per Mcf and our realized price for NGLs was $15.01 per barrel. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected.

In addition, lower commodity prices may reduce our cash flows and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower than current WTI or Henry Hub strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

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

The oil and natural gas industry is capital-intensive. We make and expect to continue to make substantial capital expenditures related to development and acquisition projects. We have funded, and we expect that we will continue to fund, our capital expenditures with cash generated by operations and borrowings under CRP's revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

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

- the prices at which our production is sold;
- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- CRP's ability to borrow under its revolving credit facility and the ability to access the capital markets.

If our revenues or the borrowing base under CRP's revolving credit facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under CRP's revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties. This, in turn, could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include the following:

- landing a wellbore in the desired drilling zone;

- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing wells include the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, the results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as anticipated, and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our development, acquisition and production activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to develop or purchase prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations resulting from wastewater disposal, emission of greenhouse gases ("GHGs") and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water and sand for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

The Silverback Acquisition involves risks associated with acquisitions and integrating acquired properties, including the potential exposure to significant liabilities, and the intended benefits of the Silverback Acquisition may not be realized.

The Silverback Acquisition involves risks associated with acquisitions and integrating acquired properties into existing operations, including that:

- our senior management's attention may be diverted from the management of daily operations to the integration of the properties acquired in the Silverback Acquisition;
- we could incur significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;
- the properties acquired in the Silverback Acquisition may not perform as well as we anticipate;
- unexpected costs, delays and challenges may arise in integrating the properties acquired in the Silverback Acquisition into our existing operations; and
- we may need to hire additional staff, devote additional resources and contract additional rigs to integrate the properties acquired in the Silverback Acquisition.

Even if we successfully integrate the properties acquired in the Silverback Acquisition into our operations, it may not be possible to realize the full benefits we anticipate or we may not realize these benefits within the expected timeframe. If we fail to realize the benefits we anticipate from the Silverback Acquisition, our business, results of operations and financial condition may be adversely affected.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. CRP's credit agreement currently restricts our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

Restrictions in CRP's existing and future debt agreements could limit our growth and ability to engage in certain activities.

CRP's credit agreement contains a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- make certain payments;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, CRP's credit agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. As of December 31, 2016, we were in full compliance with such financial ratios and covenants.

The restrictions in CRP's credit agreement may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants impose on us.

A breach of any covenant in CRP's credit agreement would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under CRP's credit agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Any significant reduction in the borrowing base under CRP's revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

CRP's revolving credit facility limits the amounts CRP can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually on April 1 and October 1. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the loan. The borrowing base will automatically be decreased by an amount equal to 25% of the aggregate notional amount of issued permitted senior unsecured notes unless such decrease is waived by the lenders. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under CRP's revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. In connection with the Silverback Acquisition, CRP entered into an amendment to its credit agreement to, among other things, increase the borrowing base from $200.0 million to $250.0 million. The next scheduled borrowing base redetermination is expected in the spring of 2017.

In the future, we may not be able to access adequate funding under CRP's revolving credit facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, CRP could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service CRP's indebtedness.

Our derivative activities could result in financial losses or could reduce our earnings.

We enter into derivative instrument contracts for a portion of our oil and natural gas production. As of December 31, 2016, we had entered into hedging contracts through December 2018 covering a total of 712 MBbls of our projected oil production and 1,460 BBtu of our projected natural gas production. In addition, as of December 31, 2016, we had entered into basis swaps covering a total of 128 MBbls of our projected oil production. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

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

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of CRP's borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected, and production declines may be greater than our estimates and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, our estimated proved reserves as of December 31, 2016, and related standardized measure were calculated under rules of the SEC using twelve-month trailing average benchmark prices of $39.25 per barrel of oil (WTI) and $2.48 per MMBtu (Henry Hub spot), which may be substantially higher or lower than the available spot prices in 2017. If spot prices are below such calculated amounts, using more recent prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits.

We will not be the operator on all of our acreage or drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

As of December 31, 2016, we have leased or acquired approximately 76,067 net acres, approximately 85% of which we operate. As of December 31, 2016, we were the operator on 1,230 of our 1,951 identified gross horizontal drilling locations. We acquired approximately 35,500 net acres in the Silverback Acquisition, approximately 90% of which we operate. Of the net acres acquired, 1,250 net acres are subject to consents to assign, which are expected to be assigned in the first quarter of 2017. We will have limited ability to exercise influence over the operations of the drilling locations operated by our partners, and there is the risk that our partners may at any time have economic, business or legal interests or goals that are inconsistent with ours. Furthermore, the success and timing of development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

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

This limited ability to exercise control over the operations and associated costs of some of our drilling locations could prevent the realization of targeted returns on capital in drilling or acquisition activities.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the amount of capital that would be necessary to drill such locations.

We have specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous identified drilling locations will ever be drilled or if we will be able to produce natural gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2016, we had identified 1,951 horizontal drilling locations on our acreage based on approximately 880-foot spacing with five to six wells per 640-acre section in the Wolfcamp zones and approximately 1,320-foot spacing with four wells per 640-acre section in the 3rd Bone Spring Sandstone, in each case, consisting of laterals ranging from 4,500 feet up to 9,500 feet. As a result of the limitations described above, we may be unable to drill many of our identified locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "—Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves." Any drilling activities we are able to conduct on these locations may not be successful or enable us to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.

As of December 31, 2016, approximately 50% of our total net acreage (approximately 51% of our operated net acreage in Reeves and Ward counties) was held by production. Of the net acreage acquired in the Silverback Acquisition, approximately 37% was held by production. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions or the leases are renewed. If our leases expire and we are unable to renew the leases, we will lose the right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

Adverse weather conditions may negatively affect our operating results and our ability to conduct drilling activities.

Adverse weather conditions may cause, among other things, increases in the costs of, and delays in, drilling or completing new wells, power failures, temporary shut-in of production and difficulties in the transportation of our oil, natural gas and NGLs. Any decreases in production due to poor weather conditions will have an adverse effect on our revenues, which will in turn negatively affect our cash flow from operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in Texas in past years. These drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Our producing properties are located in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas. At December 31, 2016, all of our total estimated proved reserves were attributable to properties located in this area.

As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is transported from the wellhead to our tank batteries by our gathering systems. The oil is then transported by the purchaser by truck to a transportation facility. Our natural gas production is generally transported by third-party gathering lines from the wellhead to a gas processing facility. We do not control these trucks and other third-party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

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

As of December 31, 2016, 70% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our PUDs as unproved reserves. Further, we may be required to write-down our PUDs if we do not drill those wells within five years after their respective dates of booking.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties.

Accounting rules that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. Recently, commodity prices have declined significantly. On December 30, 2016, the WTI spot price for crude oil was $53.75 per barrel and the Henry Hub spot price for natural gas was $3.71 per MMBtu, representing decreases of 50% and 54%, respectively, from the high of $107.95 per barrel of oil and $8.15 per MMBtu for natural gas during 2014. Likewise, NGLs have suffered significant recent declines in realized prices. NGLs are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. Lower commodity prices in the future could result in impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend upon a small number of significant purchasers for the sale of most of our oil, natural gas and NGL production.

We normally sell production to a relatively small number of customers, as is customary in our business. For the year ended December 31, 2016, sales to Plains Marketing, LP ("Plains"), Shell Trading (US) Company, and Permian Transport and Trading accounted for 48%, 22%, and 11%, respectively, of the total revenue. For the years ended December 31, 2015 and December 31, 2014, we only had one major customer, Plains, which accounted for 64% and 78%, respectively, of total revenue. The loss of any of our major purchasers could materially and adversely affect our revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any major purchaser would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our development activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse; fire, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties; and
- repair and remediation costs.

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

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, CRP's credit agreement imposes certain limitations on our ability to enter into mergers or combination transactions. CRP's credit agreement also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. Although none of our drilling locations associated with proved undeveloped reserves as of December 31, 2016 are on properties currently subject to such land use restrictions, such restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from the drilling of wells.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which industry had increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, had increased, as did the costs for those items. However, beginning in the second half of 2014, commodity prices began to decline and the demand for goods and services has subsided due to reduced activity. To the extent that commodity prices improve in the future, any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to resume or increase our development activities could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our cash flow and profitability. Furthermore, if we are unable to secure a sufficient number of drilling rigs at reasonable costs, we may not be able to drill all of our acreage before our leases expire.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005 ("EP Act of 2005"), the Federal Energy Regulatory Commission ("FERC") has civil penalty authority under the Natural Gas Act of 1938 (the "NGA") and the Natural Gas Policy Act ("NGPA") to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet “best available control technology” standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. The EPA has also announced that it intends to impose methane emission standards for existing sources as well but, to date, has not yet issued a proposal. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Most recently, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, which requires member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. The Paris Agreement entered into force in November 2016. The United States is one of over 70 nations that has ratified or otherwise consented to be bound by the agreement. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (“SDWA”) over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and also finalized rules in 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming struck down the rule in June 2016. The BLM appealed the ruling to the Tenth Circuit. This appeals remains pending. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of saltwater gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. For example, in 2015, the United States Geological Study identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In addition, a number of lawsuits have been filed in other states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Railroad Commission of Texas published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

We dispose of large volumes of saltwater gathered from our drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of saltwater gathered from our drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Our business is difficult to evaluate because we have a limited operating history, and we are susceptible to the potential difficulties associated with rapid growth and expansion.

CRP was formed in 2012 and, as a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

In addition, we have grown rapidly over the last several years. We believe that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information of CRP included elsewhere in this prospectus is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. At December 31, 2016, we had no outstanding debt. However, for example, if our entire credit facility borrowing base of $250.0 million was outstanding at December 31, 2016, a 1.0% increase in interest rates would result in an increase in annual interest expense of approximately $2.5 million, assuming the $250.0 million of debt was outstanding for the full year. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis.

As a result of future legislation, certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated and our production may be subject to the imposition of new U.S. federal taxes.

The U.S. Congress has previously considered proposals that, if enacted into law, would eliminate certain key U.S. federal income tax provisions currently available to oil and gas exploration and production companies or potentially make our operations subject to the imposition of new U.S. federal taxes. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, (iv) an extension of the amortization period for certain geological and geophysical expenditures and (v) imposition of a $10.25 per barrel fee on oil, to be paid by oil companies (but the budget does not describe where and how such a fee would be collected). It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change, as well as any changes to or the imposition of new U.S. federal, state or local taxes (including the imposition of, or increase in production, severance or similar taxes), could increase the cost of exploration and development of oil and gas resources, which would negatively affect our financial condition and results of operations.

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

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, our drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material and adverse effect on us and our financial condition.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

The standardized measure of our estimated reserves is not an accurate estimate of the current fair value of our estimated oil and natural gas reserves.

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. As a result, estimates included herein of future net cash flow may be materially different from the future net cash flows that are ultimately received, and the standardized measure of our estimated reserves included in this prospectus should not be construed as accurate estimates of the current fair value of our proved reserves.

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

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

Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.

We are subject to laws, regulations and rules enacted by national, regional and local governments and NASDAQ. In particular, we are required to comply with certain SEC, NASDAQ and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations.

Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.

We are subject to income taxes in the United States, and our domestic tax liabilities are subject to the allocation of expenses in differing jurisdictions. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of our deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- tax effects of stock-based compensation;
- costs related to intercompany restructurings;
- changes in tax laws, regulations or interpretations thereof; or
- lower than anticipated future earnings in jurisdictions where we have lower statutory tax rates and higher than anticipated future earnings in jurisdictions where we have higher statutory tax rates.

In addition, we may be subject to audits of our income, sales and other transaction taxes by U.S. federal and state authorities. Outcomes from these audits could have an adverse effect on our financial condition and results of operations.

Risks Related to Our Securities and Capital Structure

The market price of our securities may decline.

Fluctuations in the price of our securities could contribute to the loss of all or part of your investment. Prior to the closing of the Business Combination, trading in our Class A Common Stock and Public Warrants had been limited. If an active market for our securities develops and continues, the trading price of our securities could be volatile and subject to wide fluctuations in response to various factors, some of which are beyond our control. Any of the factors listed below could have a material adverse effect on your investment and our securities may trade at prices significantly below the price you paid for them. In such circumstances, the trading price of our securities may not recover and may experience a further decline.

Factors affecting the trading price of our securities may include:

- actual or anticipated fluctuations in our quarterly financial results or the quarterly financial results of companies perceived to be similar to us;
- changes in the market's expectations about our operating results;
- success of competitors;
- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or its markets in general;
- operating and stock price performance of other companies that investors deem comparable to us;
- our ability to market new and enhanced products on a timely basis;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of securities available for public sale;
- any major change in our board or management;
- sales of substantial amounts of our securities by our directors, executive officers or significant stockholders or the perception that such sales could occur; and
- general economic and political conditions such as recession; interest rate, fuel price, and international currency fluctuations; and acts of war or terrorism.

Many of the factors listed above are beyond our control. In addition, broad market and industry factors may materially harm the market price of our securities irrespective of our operating performance. The stock market in general, and NASDAQ have experienced price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of the particular companies affected. The trading prices and valuations of these stocks, and of our Class A Common Stock and Public Warrants which trade on NASDAQ, may not be predictable. A loss of investor confidence in the market for retail stocks or the stocks of other companies which investors perceive to be similar to the Company could depress the price of our securities regardless of our business, prospects, financial conditions or results of operations. A decline in the market price of our securities also could adversely affect our ability to issue additional securities and our ability to obtain additional financing in the future.

If securities or industry analysts do not publish or cease publishing research or reports about us, our business, or our market, or if they change their recommendations regarding our securities adversely, the price and trading volume of our securities could decline.

The trading market for our securities will be influenced by the research and reports that industry or securities analysts may publish about us, our business, our market, or our competitors. Securities and industry analysts do not currently, and may never, publish research on us. If no securities or industry analysts commence coverage of us, our stock price and trading volume would likely be negatively impacted. If any of the analysts who may cover us change their recommendation regarding our securities adversely, or provide more favorable relative recommendations about our competitors, the price of our securities would likely decline. If any analyst who may cover us were to cease coverage of us or fail to regularly publish reports on it, we could lose visibility in the financial markets, which could cause our stock price or trading volume to decline.

Riverstone and its affiliates own a significant percentage of our outstanding voting common stock.

Riverstone and its affiliates, including our Sponsor, beneficially own approximately 44.0% of our voting common stock and, upon the conversion of our Series B Preferred Stock, par value $0.0001 per share (the "Series B Preferred Stock"), will beneficially own approximately 49.96% of our voting common stock. As long as Riverstone and its affiliates, including our Sponsor, own or control a significant percentage of outstanding voting power, they will have the ability to strongly influence all corporate actions requiring stockholder approval, including the election and removal of directors and the size of our board of directors, any amendment of our second amended and restated certificate of incorporation (the "Charter") or amended and restated bylaws (the "Bylaws"), or the approval of any merger or other significant corporate transaction, including a sale of substantially all of our assets.

The interests of Riverstone and its affiliates, including our Sponsor, may not align with the interests of our other stockholders. Our Sponsor is in the business of making investments in companies and may acquire and hold interests in businesses that compete directly or indirectly with us. Riverstone and its affiliates, including our Sponsor, may also pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to us. In addition, our Charter provides that we renounce any interest or expectancy in the business opportunities of our officers and directors and their respective affiliates and each such party shall not have any obligation to offer us those opportunities unless presented to one of our directors or officers in his or her capacity as a director or officer.

We are no longer a "controlled company" within the meaning of the NASDAQ listing rules, and will not be able to take advantage of exemptions from certain corporate governance requirements.

Riverstone and its affiliates, including our Sponsor, no longer control a majority of our outstanding voting common stock. After the conversion of our Series B Preferred Stock, Riverstone will not own over 50.0% of our voting common stock. As a result, we are no longer a "controlled company" within the meaning of the NASDAQ listing rules, and will not be able to take advantage of exemptions from certain corporate governance requirements. Under the NASDAQ listing rules, a company of which more than 50% of the voting power is held by an individual, group or another company is a "controlled company" and is exempt from certain corporate governance requirements, including, among others, the following:

- a majority of its board of directors consist of independent directors (as defined under the NASDAQ corporate governance standards);
- its nominating and corporate governance committee consists entirely of independent directors; and
- the compensation of its executive officers be determined, or recommended to the board for determination, by a majority of independent directors in a vote by independent directors, or by a compensation committee comprised solely of independent directors.

Pursuant to the requirements of the NASDAQ listing rules, a majority of our board of directors must consist of independent directors within one year after we cease to be a controlled company. In addition, we must comply with the independent board committee requirements as they relate to the nominating and corporate governance and compensation committees on the following phase-in schedule: (1) one independent committee member at the time we cease to be a controlled company, (2) a majority of independent committee members within 90 days of the date we cease to be a controlled company and (3) all independent committee members within one year of the date we cease to be a controlled company. Our board of directors is not currently comprised of a majority of independent directors, and neither our nominating and corporate governance committee nor our compensation committee is currently comprised solely of independent directors. Accordingly, during the applicable phase-in periods provided for under the NASDAQ listing rules, you may not have the same protections afforded to stockholders of companies that are subject to all of the NASDAQ corporate governance standards.

Anti-takeover provisions contained in our Charter and Bylaws, as well as provisions of Delaware law, could impair a takeover attempt.

Our Charter and Bylaws contain provisions that could have the effect of delaying or preventing changes in control or changes in our management without the consent of our board of directors. These provisions include:

- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;
- the exclusive right of our board of directors to elect a director to fill a vacancy created by the expansion of the board of directors or the resignation, death, or removal of a director, which prevents stockholders from being able to fill vacancies on our board of directors;
- the ability of our board of directors to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;
- a prohibition on stockholder action by written consent, which forces stockholder action to be taken at an annual or special meeting of our stockholders;

- the requirement that an annual meeting of stockholders may be called only by the chairman of the board of directors, the chief executive officer, or the board of directors, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;
- limiting the liability of, and providing indemnification to, our directors and officers;
- controlling the procedures for the conduct and scheduling of stockholder meetings;
- providing that directors may be removed prior to the expiration of their terms by stockholders only for cause; and
- advance notice procedures that stockholders must comply with in order to nominate candidates to our board of directors or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of the Company.

These provisions, alone or together, could delay hostile takeovers and changes in control of the Company or changes in our board of directors and management.

As a Delaware corporation, we are also subject to provisions of Delaware law, including Section 203 of the Delaware General Corporation Law (the "DGCL"), which prevents some stockholders holding more than 15% of our outstanding voting common stock from engaging in certain business combinations without approval of the holders of substantially all of our outstanding voting common stock. Any provision of our Charter or Bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their securities and could also affect the price that some investors are willing to pay for our securities.

The JOBS Act permits "emerging growth companies" like us to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies.

We qualify as an "emerging growth company" as defined in the JOBS Act. As such, we take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies for as long as we continue to be an emerging growth company, including (i) the exemption from the auditor attestation requirements with respect to internal control over financial reporting under Section 404 of the Sarbanes-Oxley Act, (ii) the exemptions from say-on-pay, say-on-frequency and say-on-golden parachute voting requirements and (iii) reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements. As a result, our stockholders may not have access to certain information they deem important. We will remain an emerging growth company until the earliest of (i) the last day of the fiscal year (a) following February 28, 2021, the fifth anniversary of our IPO, (b) in which we have total annual gross revenue of at least $1.0 billion or (c) in which we are deemed to be a large accelerated filer, which means the market value of our Class A Common Stock that is held by non-affiliates exceeds $700 million as of the last business day of our prior second fiscal quarter, and (ii) the date on which we have issued more than $1.0 billion in non-convertible debt during the prior three-year period.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the exemption from complying with new or revised accounting standards provided in Section 7(a)(2)(B) of the Securities Act as long as we are an emerging growth company. An emerging growth company can therefore delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies, but any such election to opt out is irrevocable. We have elected not to opt out of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, we, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of our financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accountant standards used.

We cannot predict if investors will find our Class A Common Stock less attractive because we will rely on these exemptions. If some investors find our Class A Common Stock less attractive as a result, there may be a less active trading market for our Class A Common Stock and our stock price may be more volatile.

Non-U.S. holders may be subject to U.S. income tax with respect to gain on disposition of their Class A Common Stock.

We believe that we are a United States real property holding corporation (a "USRPHC"). As a result, Non-U.S. holders (defined below in the section entitled "Material U.S. Federal Income Tax Considerations") that own (or are treated as owning under constructive ownership rules) more than a specified amount of our Class A Common Stock during a specified time period may be subject to U.S. federal income tax on a sale, exchange, or other disposition of such Class A Common Stock and may be required to file a U.S. federal income tax return. If you are a Non-U.S. holder, we urge you to consult your tax advisors regarding the tax consequences of such treatment.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment-related disputes. We do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our Class A Common Stock and Public Warrants are currently quoted on NASDAQ under the symbols "CDEV" and "CDEVW," respectively. Through October 11, 2016, our Class A Common Stock was quoted under the symbol "SRAQ." The following table sets forth, for the calendar quarter indicated, the high and low sales price per share of Class A Common Stock as reported on NASDAQ for the periods presented:

	Class A Common Stock (CDEV)	
	High	**Low**
2016:		
Fourth Quarter	$ 20.97	$ 13.31
Third Quarter	16.10	9.65
Second Quarter(1)	10.70	9.65
First Quarter(2)	N/A	N/A

(1) Beginning on April 15, 2016.

(2) Since the Class A Common Stock commenced separate trading on April 15, 2016, there is no information presented for the Class A Common Stock for the first quarter of 2016.

As of March 7, 2017, there were 254 holders of record of our Class A Common Stock.

Dividend Policy

We have not paid any cash dividends on our Class A Common Stock or Class C Common Stock to date. Our board of directors may from time to time consider whether or not to institute a dividend policy. It is our present intention to retain any earnings for use in our business operations and, accordingly, we do not anticipate the board of directors declaring any dividends in the foreseeable future.

ITEM 6. SELECTED FINANCIAL DATA

The following data should be read in conjunction with *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated and combined financial statements included in this report.

The following table shows selected historical financial information of CRP for the periods and as of the dates indicated. For all periods ending on or prior to and all dates as of or prior to October 15, 2014, the date on which Celero conveyed all of its oil and natural gas properties to CRP, the following table reflects the combined results of CRP and Celero, and for all periods and dates subsequent to October 15, 2014, reflects the results of CRP.

The selected historical consolidated and combined financial information of CRP as of and for the years ended December 31, 2015, 2014 and 2013 was derived from the audited historical consolidated and combined financial statements of CRP included elsewhere in this prospectus. The selected historical interim consolidated financial information of CRP as of September 30, 2016 and for the nine months ended September 30, 2016 and 2015 was derived from the unaudited interim condensed consolidated financial statements of CRP included elsewhere in this prospectus.

CRP's historical results are not necessarily indicative of future operating results. The selected consolidated and combined financial information should be read in conjunction with *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* and the historical consolidated and combined financial statements of CRP and accompanying notes included in *Part II, Item 8. Financial Statements and Supplementary Data*.

(in thousands, except per share, production and per BOE data)	Successor: October 11, 2016 through December 31, 2016	Predecessor: January 1, 2016 through October 10, 2016	Predecessor: Year Ended December 31, 2015	Predecessor: Year Ended December 31, 2014	Predecessor: Year Ended December 31, 2013
Statements of Operations Data:					
Total revenues	$ 29,717	$ 69,116	$ 90,460	$ 131,825	$ 71,974
Net (loss) income attributable to Centennial Resource Development, Inc.	(8,081)	(218,724)	(38,325)	17,790	3,618
Income (loss) per share:					
Basic	$ (0.05)				
Diluted	$ (0.05)				
Production Data:					
Oil (MBbls)	523	1,584	1,830	1,428	713
Natural gas (MMcf)	1,113	2,660	3,058	2,112	797
NGLs (MBbls)	96	253	331	235	98
Total (MBoe)	805	2,280	2,671	2,015	944
Expenses per Boe:					
Lease operating expenses	$ 4.40	$ 4.84	$ 7.93	$ 8.78	$ 20.24
Severance and ad valorem taxes	2.03	1.62	1.88	3.41	4.40
Transportation, processing, gathering and other operating expense	2.72	2.01	2.15	2.37	1.37
Depreciation, depletion, amortization and accretion of asset retirement obligations	18.48	27.62	33.73	34.30	31.02
Abandonment expense and impairment of unproved properties	—	1.12	2.85	9.94	9.07
Exploration	1.05	—	0.03	—	—
Contract termination and rig stacking	—	—	0.89	—	—
General and administrative expenses	17.04	11.22	5.32	15.73	17.84
Cash Flows Data:					
Net cash provided by operating activities	$ 9,410	$ 51,740	$ 68,882	$ 97,248	$ 13,416
Net cash used by investing activities	(1,749,733)	(101,434)	(198,635)	(163,380)	(136,517)
Net cash provided by financing activities	1,874,268	47,926	118,504	36,966	118,742

(in thousands)	Successor: December 31, 2016	Predecessor: December 31, 2015	Predecessor: December 31, 2014	Predecessor: December 31, 2013
Balance Sheet Data:				
Total assets	$ 2,651,642	$ 616,295	$ 615,769	$ 472,085
Long-term debt	—	138,649	129,568	29,000
Dividends per share	—	—	—	—

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated and combined financial statements and related notes in "Part II, Item 8. Financial Statements and Supplementary Data." The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions and resources. Please see "Cautionary Statement Concerning Forward-Looking Statements" and "Part I, Item 1A. Risk Factors" in this Report.

Overview

We are an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. Our horizontal wells span an area approximately 45 miles long by 20 miles wide where we have established commercial production in five distinct zones: the 3rd Bone Spring Sandstone, Upper Wolfcamp A, Lower Wolfcamp A, Wolfcamp B and Wolfcamp C.

We have no direct operations and no significant assets other than our current ownership of an approximate 92% membership interest in CRP. CRP is considered our accounting Predecessor and, accordingly, the following financial results and discussion and analysis reflect the results of CRP prior to the closing of the Business Combination.

Silver Run Business Combination

Centennial Resource Development, Inc. (the "Company," "Centennial," "we," "us," or "our") was originally incorporated in Delaware on November 4, 2015 as a special purpose acquisition company under the name Silver Run Acquisition Corporation for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving us and one or more businesses.

On February 29, 2016, we consummated our initial public offering of Units each consisting of one share of Class A Common Stock and one-third of one Public Warrant. On October 11, 2016, we consummated the acquisition of approximately 89% of the outstanding membership interests in Centennial Resource Production, LLC, a Delaware limited liability company ("CRP" and such acquisition, the "Business Combination").

The application of acquisition accounting for the Business Combination significantly affected certain assets, liabilities, and expenses. As a result, financial information as of December 31, 2016 and in the period October 11, 2016 through December 31, 2016 is not necessarily comparable to CRP's predecessor financial information.

Presentation of Financial and Operating Data

As a result of the Business Combination, we are the acquirer for accounting purposes, and CRP is the acquiree and accounting Predecessor. Our financial statement presentation distinguishes a "Predecessor" for CRP for periods prior to the Business Combination. We are the "Successor" for periods after the Business Combination, which includes consolidation of CRP subsequent to the Business Combination on October 11, 2016.

For all periods ending on or before October 15, 2014 and for all dates on or before October 15, 2014, the historical financial results contained herein reflect the combined results of (i) CRP and (ii) Celero Energy Company, LP, a Delaware limited partnership ("Celero"), which was formed in 2006 to focus on the development and acquisition of oil and natural gas properties in Texas and New Mexico, primarily in the Permian Basin in West Texas. On October 15, 2014, Celero conveyed substantially all of its oil and natural gas properties and other assets to CRP in exchange for membership interests in CRP, and as a result, subsequent to October 15, 2014, the historical financial results contained herein reflect the results of CRP. Except as the context otherwise requires, references in the following discussion to the "Company," "we," "our" or "us" with respect to periods prior to the closing of the Business Combination are to CRP and its operations prior to the closing of the Business Combination.

Recent Developments

Silverback Acquisition

On December 28, 2016, we completed the acquisition (the "Silverback Acquisition") of leasehold interests and related upstream assets in Reeves County, Texas from Silverback Exploration, LLC and Silverback Operating, LLC (collectively, "Silverback") for a cash purchase price of approximately $855.0 million, subject to customary purchase price adjustments. The assets acquired from Silverback include 31 operated producing horizontal wells and approximately 35,500 net acres that directly offset our existing acreage in Reeves County, Texas. We operate approximately 90% of, and have an approximate 90% working interest in this acreage. Of the net acres acquired, 1,250 net acres are subject to consents to assign, which are expected to be assigned in the first quarter of 2017. The Wolfcamp A and B are producing horizons on this acreage and we believe that this acreage may be prospective for the Wolfcamp C and Avalon and Bone Spring shale formations.

Issuance of Class A Common Stock and Preferred Stock in Private Placements

In connection with the Silverback Acquisition, we issued and sold in private placements (i) 3,473,590 shares of Class A Common Stock and 104,400 shares of Series B Preferred Stock to the Riverstone Purchasers and (ii) 33,012,380 shares of our Class A Common Stock to certain other investors, resulting in gross proceeds of approximately $910.0 million. We used the proceeds from the private placements to fund the cash consideration for the Silverback Acquisition and expect to use any remaining proceeds for general corporate purposes.

The shares of Series B Preferred Stock are automatically convertible into shares of our Class A Common Stock on a 250-to-1 basis (subject to certain adjustments) at such time as we receive stockholder approval for the issuance of such shares of Class A Common Stock in compliance with NASDAQ listing rules ("Stockholder Approval"). We intend to call a special meeting of our stockholders in order to receive such approval. For a more detailed description of the Series B Preferred Stock, refer to *Note 7—Shareholders' and Owners' Equity* to the Consolidated and Combined Financial Statements in Part II, Item 8. Financial Statements and Supplementary Data in this annual report.

Credit Agreement Amendment

On December 28, 2016, in connection with the closing of the Silverback Acquisition, CRP entered into an amendment to its credit agreement to, among other things, increase the borrowing base thereunder from $200.0 million to $250.0 million.

Redemption of Public Warrants

On March 1, 2017, the Company delivered a notice of redemption of the Public Warrants, announcing its intention to redeem any unexercised and outstanding Public Warrants on March 31, 2017 for $0.01 per Public Warrant. As permitted under the warrant agreement that provides the terms of the Public Warrants, the notice of redemption requires all holders exercising their Public Warrants prior to March 31, 2017 to do so on a "cashless basis" and surrender their Public Warrants for a number of shares of Class A Common Stock equal to the product of the quotient equal to (i) the difference between $11.50 and $18.44 (the average last sale price of the Class A Common Stock for the ten trading days ending on February 24, 2017) divided by (ii) $18.44, or approximately 0.376, multiplied by the number of Public Warrants held by such holder, rounded down to the nearest whole share. Assuming all warrants are exercised by holders, Centennial will issue approximately 6.27 million shares of Class A Common Stock to the Public Warrant holders, resulting in a share count of approximately 253 million shares outstanding, which includes Class A Common Stock shares, the shares of Series B Preferred Stock held by Riverstone (assuming conversion to Class A Common Stock on a 250-to-one basis), and the shares of Class C Common Stock held by the Centennial Contributors. The Private Placement Warrants are non-redeemable so long as they are held by our Sponsor or its permitted transferees.

Market Conditions

The oil and gas industry is cyclical and commodity prices can be volatile. In the second half of 2014, oil prices began a rapid and significant decline as global and domestic supply began to outpace demand. During 2015 and 2016, global and domestic oil supply continued to outpace demand resulting in further deterioration in realized oil prices. In 2016, oil prices were volatile, and it is likely that oil prices will continue to fluctuate due to the ongoing global supply and demand imbalance, high inventories and geopolitical factors.

Our revenue, profitability and future growth are highly dependent on the prices we receives for our oil and natural gas production, as well as NGLs that are extracted from our natural gas during processing. Compared to 2014, our realized oil price for 2015 fell 47% to $42.43 per barrel, and our realized oil price for 2016 further decreased to $39.91 per barrel. Similarly, our realized natural gas price for 2015 dropped 43% to $2.60 per Mcf and our realized price for NGLs declined 52% to $14.66 per barrel. For 2016, our realized price for natural gas was $2.52 per Mcf and our realized price for NGLs was $15.01 per barrel. Lower oil, natural gas and NGL prices may not only decrease our revenues, but also may reduce the amount of oil, natural gas and NGLs that we can produce economically and therefore potentially lower our oil, natural gas and NGL reserves.

Lower commodity prices in the future could result in impairments of our properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower oil, natural gas and NGL prices may also reduce the borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant non-cash fair value losses being incurred on our derivatives, which could cause us to experience net losses when oil and natural gas prices rise.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts on its oil and natural gas production;
- production results;
- lease operating expenses; and
- Adjusted EBITDAX[(1)].

(1) Adjusted EBITDAX is not presented in accordance with generally accepted accounting principles in the United States (“GAAP”). Please see "Non-GAAP Financial Measure" below for a reconciliation.

Sources of our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. For the period from October 11, 2016, through December 31, 2016 (Successor), oil sales, natural gas sales and NGL sales contributed 82%, 12%, and 7%, respectively, of our total revenues. For the period from January 1, 2016, through October 10, 2016 (Predecessor), oil sales, natural gas sales and NGL sales contributed 87%, 9% and 5%, respectively of our total revenues. Our oil, natural gas and NGL revenues do not include the effects of derivatives for either period.

Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Oil, natural gas and NGL prices are market driven and have been historically volatile, and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors. See "—Market Conditions" for information regarding the current commodity price environment. A $1.00 per barrel change in our realized oil price would have resulted in a $0.5 million and a $1.6 million change in oil revenues for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), respectively. A $0.10 per Mcf change in our realized natural gas price would have resulted in a $0.1 million and a $0.3 million change in our natural gas revenues for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), respectively. A $1.00 per barrel change in our realized NGL prices would have resulted in a $0.1 million and a $0.3 million change in NGL revenues for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), respectively.

The following table presents our average realized commodity prices, as well as the effects of derivative settlements.

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
			2015	2014
Crude Oil (per Bbl):				
Average NYMEX price	$ 49.21	$ 41.75	$ 48.76	$ 92.86
Average realized price, before the effects of derivative settlements	46.49	37.74	42.43	80.50
Effects of derivative settlements	2.02	10.49	19.18	3.23
Natural Gas:				
Average NYMEX price (per MMBtu)	$ 3.18	$ 2.37	$ 2.63	$ 4.26
Average realized price, before the effects of derivative settlements (per Mcf)	3.10	2.27	2.60	4.58
Effects of derivative settlements (per Mcf)	—	—	0.43	—
NGLs (per Bbl):				
Average realized price	$ 20.36	$ 12.98	$ 14.66	$ 30.64

While quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location and transportation differentials for these products.

See “—Results of Operations” below for an analysis of the impact changes in realized prices had on our revenues.

Operating Costs and Expenses

Costs associated with producing oil, natural gas and NGLs are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production, and others are a function of the number of wells we own. As of December 31, 2016 (Successor) and December 31, 2015 (Predecessor), CRP owned interests in 208 and 138 gross wells, respectively.

Lease Operating Expenses. Lease operating expenses ("LOE") are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water injection and disposal, materials and supplies comprise the most significant portion of our LOE. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased LOE in periods during which they are performed. Certain of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we incur power costs in connection with various production-related activities, such as pumping to recover oil and natural gas and separation and treatment of water produced in connection with our oil and natural gas production.

We monitor our operations to ensure that we are incurring LOE at an acceptable level. For example, we monitor our LOE per Boe to determine if any wells or properties should be shut in, recompleted or sold. This unit rate also allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers. Although we strive to reduce our LOE, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate our properties or makes acquisitions and dispositions of properties. For example, we may increase field level expenditures to optimize our operations, incurring higher expenses in one quarter relative to another, or we may acquire or dispose of properties that have different LOE per Boe. These initiatives would influence our overall operating cost and could cause fluctuations when comparing LOE on a period to period basis.

Severance and Ad Valorem Taxes. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by federal, state or local taxing authorities. In general, the severance taxes we pay correlate to the changes in oil, natural gas and NGLs revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties, which also trends with oil and natural gas prices.

Transportation, Processing, Gathering and Other Operating Expenses. Transportation, processing, gathering and other operating expenses principally consist of expenditures to prepare and transport production from the wellhead to a specified sales point and gas processing costs. These costs will fluctuate with increases or decreases in production volumes, contractual fees and changes in fuel and compression costs.

Depreciation, Depletion, Amortization, and Accretion of Asset Retirement Obligations. Depreciation, depletion, amortization, and accretion of asset retirement obligations ("DD&A") is the systematic expensing of the capitalized costs incurred to acquire and develop oil and natural gas properties. We use the successful efforts method of accounting for oil and natural gas activities and, as such, we capitalize all costs associated with our development and acquisition efforts and all successful exploration efforts, which are then allocated to each unit of production using the unit of production method. Please read "—Critical Accounting Policies and Estimates—Successful Efforts Method of Accounting for Oil and Natural Gas Activities" for further discussion.

Impairment Expense. We review our proved properties and unproved leasehold costs for impairment whenever events and changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Please read "—Critical Accounting Policies and Estimates—Impairment of Oil and Natural Gas Properties" for further discussion.

General and Administrative Expenses. General and administrative ("G&A") expenses are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and to development operations, audit and other fees for professional services and legal compliance.

Interest Expense. We finance a portion of our working capital requirements and capital expenditures with borrowings under our revolving credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our revolving credit facility in interest expense.

Derivative Gain (Loss). Derivative instruments are recognized on the balance sheet as either assets or liabilities measured at fair value. We have not elected to apply cash flow hedge accounting, and consequently, recognize gains and losses in earnings rather than deferring such amounts in other comprehensive income as allowed under cash flow hedge accounting. Fair value gains or losses, as well as cash receipts or payments on settled derivative contracts, are recognized in our consolidated and combined statements of operations. Cash flows from derivatives are reported as cash flows from operating activities.

A discussion of changes in operating costs and expenses is included in Results of Operations, below.

Results of Operations

For the Periods From October 11, 2016, Through December 31, 2016 (Successor) and January 1, 2016, Through October 10, 2016 (Predecessor) Compared to Year Ended December 31, 2015 (Predecessor)

Oil, Natural Gas and NGL Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Successor	Predecessor	Combined	Predecessor	Increase/(Decrease)	
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2016	Year Ended December 31, 2015	$	%
Revenues (in thousands):						
Oil sales	$ 24,313	$ 59,787	$ 84,100	$ 77,643	$ 6,457	8 %
Natural gas sales	3,449	6,045	9,494	7,965	1,529	19 %
NGL sales	1,955	3,284	5,239	4,852	387	8 %
Total Revenues	$ 29,717	$ 69,116	$ 98,833	$ 90,460	$ 8,373	9 %
Average sales price (1):						
Oil (per Bbl)	$ 46.49	$ 37.74	$ 39.91	$ 42.43	$ (2.52)	(6)%
Natural gas (per Mcf)	3.10	2.27	2.52	2.60	(0.08)	(3)%
NGL (per Bbl)	20.36	12.98	15.01	14.66	0.35	2 %
Total (per Boe)	$ 36.92	$ 30.31	$ 32.04	$ 33.87	$ (1.83)	(5)%
Production:						
Oil (MBbls)	523	1,584	2,107	1,830	277	15 %
Natural gas (MMcf)	1,113	2,660	3,773	3,058	715	23 %
NGLs (MBbls)	96	253	349	331	18	5 %
Total (MBoe)(2)	805	2,280	3,085	2,671	414	15 %
Average daily production volume:						
Oil (Bbls/d)	6,378	5,577	5,757	5,014	743	15 %
Natural gas (Mcf/d)	13,573	9,366	10,309	8,378	1,931	23 %
NGLs (Bbls/d)	1,171	891	954	907	47	5 %
Total (Boe/d)(2)	9,811	8,029	8,429	7,317	1,112	15 %

(1) Average prices shown in the table reflect prices before the effects of our realized commodity derivative transactions.

(2) Total may not sum or recalculate due to rounding.

As reflected in the table above, our combined revenues for 2016 were 9%, or $8.4 million, higher than total revenues for 2015. The increase was primarily due to a 15% increase in production sold in 2016, which was partially offset by a 5% decrease in average sales price per Boe, compared to the prior year.

Combined oil sales increased 8%, or $6.5 million, for 2016 compared to the prior year period primarily due to a 15% increase in oil volumes sold, partially offset by an 6% decrease in the average sales price for oil. Combined natural gas sales increased 19%, or $1.5 million, for 2016 compared to the prior year period primarily due to a 23% increase in natural gas volumes sold, partially offset by a 3% decrease in the average sales price for natural gas. Combined NGL sales increased 8%, or $0.4 million, for 2016 compared to the prior year period primarily due to a 5% increase in the NGL volumes sold.

Operating Expenses. We present per Boe information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis.

The following table sets forth selected operating data for the periods indicated:

	Successor	Predecessor	Combined	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2016	Year Ended December 31, 2015	Increase/(Decrease) $	%
Operating Expenses (in thousands):						
Lease operating expenses	$ 3,541	$ 11,036	$ 14,577	$ 21,173	$ (6,596)	(31)%
Severance and ad valorem taxes	1,636	3,696	5,332	5,021	311	6 %
Transportation, processing, gathering and other operating expense	2,187	4,583	6,770	5,732	1,038	18 %
Production costs per Boe:						
Lease operating expenses	$ 4.40	$ 4.84	$ 4.73	$ 7.93	$ (3.20)	(40)%
Severance and ad valorem taxes	2.03	1.62	1.73	1.88	(0.15)	(8)%
Transportation, processing, gathering and other operating expense	2.72	2.01	2.19	2.15	0.04	2 %

Lease Operating Expenses. We experience volatility in our LOE as a result of the impact industry activity has on service provider costs and seasonality in workover expense. Combined LOE decreased 31%, or $6.6 million, in 2016 compared to 2015, due in part to service providers lowering costs in light of the weak commodity price environment. Additionally, the number of wells placed on production in 2016 decreased 29% compared to 2015. Workover expense decreased $2.0 million and we converted several rental units to permanent pumping units decreasing the amounts of rental expense by approximately $1.6 million in 2016 compared to the prior year period. Lastly, we decreased the use of contract labor and expenses related to repairs and maintenance by $1.2 million and $1.9 million, respectively, in 2016 compared to 2015.

Severance and Ad Valorem Taxes. Severance taxes are primarily based on the market value of our production at the wellhead and ad valorem taxes are generally based on the valuation of our oil and natural gas properties and vary across the different counties in which we operate. Combined severance and ad valorem taxes increased 6%, or $0.3 million, in 2016 compared to 2015, primarily due to higher sales volumes, partially offset by lower realized commodity prices. Combined severance and ad valorem taxes as a percentage of our revenue were 5.4% for 2016 compared to 5.6% for the prior year period.

Transportation, Processing, Gathering and Other Operating Expenses. Combined transportation, processing, gathering and other operating expenses in 2016 increased 18%, or $1.0 million, compared to 2015, primarily due to an increase in natural gas production of 23% year over year, partially offset by lower realized commodity prices

Depreciation, Depletion, Amortization and Accretion of Asset Retirement Obligations. The following table summarizes our DD&A for the periods indicated:

	Successor	Predecessor	
(in thousands)	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Depreciation, depletion, amortization and accretion of asset retirement obligations	$ 14,877	$ 62,964	$ 90,084
Depreciation, depletion, amortization and accretion of asset retirement obligations per Boe	18.48	27.62	33.73

Our DD&A rate can fluctuate as a result of impairments, dispositions, finding and development costs and proved reserve volumes. For the period from October 11, 2016, through December 31, 2016 (Successor), DD&A expense for the period was $14.9 million or $18.48 per Boe.

For the period from January 1, 2016, through October 10, 2016 (Predecessor), DD&A expense was $63.0 million or $27.62 per Boe. In 2015, DD&A expense was $90.1 million or $33.73 per Boe. The decrease in DD&A rate is primarily due to lower development costs and reserve additions.

Abandonment Expense and Impairment of Unproved Properties. The following table summarizes our abandonment expense and impairment of unproved properties for the periods indicated:

	Successor	Predecessor	
(in thousands)	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Abandonment expense and impairment of unproved properties	$ —	$ 2,545	$ 7,619

For the period from October 11, 2016, through December 31, 2016 (Successor), we did not have any abandonment expense and impairment of unproved property. For the period from January 1, 2016, through October 10, 2016 (Predecessor) and in 2015, we recorded $2.5 million and $7.6 million, respectively, of leasehold expirations attributable to leases that expired during the period or that we expect to expire in the future.

Exploration. The following table summarizes our exploration expense for the periods indicated:

	Successor	Predecessor	
(in thousands)	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Exploration	$ 844	$ —	$ 84

For the period from October 11, 2016, through December 31, 2016 (Successor), we recorded $0.8 million of exploration expense related to seismic data that will be used for exploration. For the period from January 1, 2016, through October 10, 2016 (Predecessor), we did not incur any exploration expense. For 2015, we recorded $0.1 million of exploration expense for logging analyses.

Contract Termination and Rig Stacking. The following table summarizes our contract termination and rig stacking expenses for the periods indicated:

	Successor	Predecessor	
(in thousands)	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Contract termination and rig stacking	$ —	$ —	$ 2,387

For the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), we did not incur any drilling and rig termination fees, as compared to $2.4 million in 2015. In light of the low commodity price environment, we curtailed drilling activity beginning in the first quarter of 2015, and as a result, we incurred drilling and rig termination fees of $2.4 million in 2015.

General and Administrative Expenses. The following table summarizes our G&A expenses for the periods indicated:

	Successor	Predecessor	
(in thousands)	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
General and administrative expenses	$ 13,715	$ 25,581	$ 14,206
General and administrative expenses per Boe	17.04	11.22	5.32

For the period from October 11, 2016, through December 31, 2016 (Successor), G&A expenses were $13.7 million or $17.04 per Boe. G&A expenses for the Successor period included $4.1 million of transactional expenses primarily attributable to the consummation of the Business Combination. Additionally, G&A expenses for the Successor period included $1.0 million of non-cash charges resulting from the issuance of restricted stock and stock option awards. We have recognized non-cash equity based compensation cost as follows:

(in thousands)	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Restricted stock awards	$ 405	$ —	$ —
Stock option awards	928	—	—
Total equity based compensation expense	$ 1,333	$ —	$ —

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of shares granted. Refer to *Note 8—Equity Based Compensation* to the Consolidated and Combined Financial Statements in Part II, Item 8. Financial Statements and Supplementary Data in this annual report for further discussion regarding our equity based compensation.

For the period from January 1, 2016, through October 10, 2016 (Predecessor), G&A expenses were $25.6 million or $11.22 per Boe. In 2015, G&A expenses were $14.2 million or $5.32 per Boe. G&A expenses increased 80%, or $11.4 million, between these two periods primarily due to $15.8 million of transaction expenses incurred in connection with the Business Combination during the period from January 1, 2016, through October 10, 2016.

Incentive Compensation. The following table summarizes our incentive compensation for the period indicated:

(in thousands)	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Incentive unit compensation	$ —	$ 165,394	$ —

For the period from January 1, 2016, through October 10, 2016 (Predecessor), we recorded non-cash incentive compensation of $165.4 million related to the consummation of the Business Combination.

Gain on Sale of Oil and Natural Gas Properties. The following table summarizes our gain on sale of oil and natural gas properties for the periods indicated:

(in thousands)	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Gain on sale of oil and natural gas properties	$ 24	$ 11	$ 2,439

For the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor) we recorded immaterial net gains on the sale of oil and natural gas properties. In 2015 (Predecessor), we recorded a net gain of $2.4 million, which was primarily attributable to a gain associated with the sale of non-core unproved property to an unrelated third party.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

(in thousands)	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Other (expense) income:			
Interest expense	$ (378)	$ (5,626)	$ (6,266)
Loss on derivative instruments	(1,548)	(6,838)	20,756
Other income	—	6	20
Total other expense	$ (1,926)	$ (12,458)	$ 14,510
Income tax benefit	$ —	$ 406	$ 572

Interest Expense. For the period from October 11, 2016, through December 31, 2016 (Successor) we incurred interest expense of $0.4 million primarily related to the commitment fee we pay for unused amounts on our revolving credit facility. For the period from January 1, 2016, through October 10, 2016 (Predecessor), we incurred interest expense of $5.6 million related to borrowings under our revolving credit facility and interest on our term loan. In 2015 (Predecessor), we incurred interest expense of $6.3 million related to borrowings under our revolving credit facility and interest on our term loan.

Gain on Derivative Instruments. For the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), we recognized derivatives losses of $1.5 million and $6.8 million, respectively. In 2015 (Predecessor), we recognized a $20.8 million derivative gain. Net losses and gains on our derivatives are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments.

Year Ended December 31, 2015 (Predecessor) Compared to Year Ended December 31, 2014 (Predecessor)

	Predecessor			
	Year Ended December 31,		Increase/(Decrease)	
	2015	2014	$	%
Revenues (in thousands):				
Oil sales	$ 77,643	$ 114,955	$ (37,312)	(32)%
Natural gas sales	7,965	9,670	(1,705)	(18)%
NGL sales	4,852	7,200	(2,348)	(33)%
Total Revenues	$ 90,460	$ 131,825	$ (41,365)	(31)%
Average realized prices (excluding effect of hedges):				
Oil (per Bbl)	$ 42.43	$ 80.50	$ (38.07)	(47)%
Natural gas (per Mcf)	2.60	4.58	(1.98)	(43)%
NGL (per Bbl)	14.66	30.64	(15.98)	(52)%
Total (per Boe)	$ 33.87	$ 65.42	$ (31.55)	(48)%
Production:				
Oil (MBbls)	1,830	1,428	402	28 %
Natural gas (MMcf)	3,058	2,112	946	45 %
NGLs (MBbls)	331	235	96	41 %
Total (MBoe)(2)	2,671	2,015	656	33 %
Average daily production volumes:				
Oil (Bbls/d)	5,014	3,912	1,102	28 %
Natural gas (Mcf/d)	8,378	5,786	2,592	45 %
NGLs (Bbls/d)	907	644	263	41 %
Total (Boe/d)(2)	7,317	5,521	1,796	33 %

(1) Average prices shown in the table reflect prices before the effects of our realized commodity derivative transactions.

(2) Total may not sum or recalculate due to rounding.

As reflected in the table above, our total revenues for 2015 was 31%, or $41.4 million, lower than in 2014. The decrease was primarily due to a significant decrease in commodity prices, resulting in a 48% decrease in the average sales price per Boe. The decrease was offset in part by a 33% increase in average daily production sold in 2015 compared to 2014. The increase in average daily production in 2015 was negatively impacted by property divestitures that occurred in 2014. In 2014, average daily production attributable to the property dispositions approximated 310 Boe/d.

Oil sales decreased 32%, or $37.3 million, primarily as result of a 47% decrease in average sales price for oil, offset by a 28% increase in oil volumes sold. Natural gas sales decreased 18%, or $1.7 million, primarily as a result of 43% decrease in the average sales price for natural gas, offset by a 45% increase in natural gas volumes sold. NGL sales decreased 33%, or $2.3 million, primarily as a result of a 52% decrease in the average price for NGLs, offset by a 41% increase in NGL volumes sold.

Operating Expenses. We present per Boe information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis.

The following table summarizes our operating expenses for the periods indicated:

	Predecessor			
	Year Ended December 31,		Increase/(Decrease)	
	2015	2014	$	%
Operating Expenses (in thousands):				
Lease operating expenses	$ 21,173	$ 17,690	$ 3,483	20 %
Severance and ad valorem taxes	5,021	6,875	(1,854)	(27)%
Transportation, processing, gathering and other operating expense	5,732	4,772	960	20 %
Depreciation, depletion, amortization and accretion of asset retirement obligations	90,084	69,110	20,974	30 %
Abandonment expense and impairment of unproved properties	7,619	20,025	(12,406)	(62)%
Exploration	84	—	84	100 %
Contract termination and rig stacking	2,387	—	2,387	100 %
General and administrative expenses	14,206	31,694	(17,488)	(55)%
Total operating expenses before gain on oil and natural gas properties	146,306	150,166	(3,860)	(3)%
Gain (loss) on sale of oil and natural gas properties	2,439	(2,096)	NM	NM
Total operating expenses after gain (loss) on oil and natural gas properties	$ 143,867	$ 152,262	$ (8,395)	(6)%
Production costs per Boe:				
Lease operating expenses	$ 7.93	$ 8.78	$ (0.85)	(10)%
Severance and ad valorem taxes	1.88	3.41	(1.53)	(45)%
Transportation, processing, gathering and other operating expense	2.15	2.37	(0.22)	(9)%
Depreciation, depletion, amortization and accretion of asset retirement obligations	33.73	34.30	(0.57)	(2)%
Abandonment expense and impairment of unproved properties	2.85	9.94	(7.09)	(71)%
Exploration	0.03	—	0.03	100 %
Contract termination and rig stacking	0.89	—	0.89	100 %
General and administrative expenses	5.32	15.73	(10.41)	(66)%
Total operating expenses per Boe	$ 54.78	$ 74.53	$ (19.75)	(26)%

Lease Operating Expenses. We experience volatility in our LOE as a result of the impact industry activity has on service provider costs and seasonality in workover expense. LOE increased 20%, or $3.5 million, in 2015 as compared to 2014, as we continued to put new wells on production, resulting in increased needs for compression, rental equipment, fuel, saltwater disposal and chemicals. We also had a year-over-year increase in workover expense.

Severance and Ad Valorem Taxes. Severance taxes are primarily based on the market value of our production at the wellhead and ad valorem taxes are generally based on the valuation of our oil and natural gas properties and vary across the different counties in which we operate. Severance and ad valorem taxes decreased 27%, primarily due to lower production revenues primarily as a result of lower realized commodity prices. Severance and ad valorem taxes as a percentage of our revenue was 5.6% for 2015 compared to 5.2% for 2014.

Transportation, Processing, Gathering and Other Operating Expenses. Transportation, processing, gathering and other operating expenses increased 20%, or $1.0 million. In 2015, lower prices for natural gas and NGLs resulted in lower costs associated with fuel and processing fees, which were partially offset by higher processing volumes.

Depreciation, Depletion, Amortization and Accretion of Asset Retirement Obligations. Our DD&A rate can fluctuate as a result of impairments, dispositions, finding and development costs and proved reserve volumes. DD&A expense increased 30%, or $21.0 million, primarily due to an increase in production volumes. DD&A per Boe was $33.73 for 2015, a slight decrease as compared to $34.30 in 2014.

Abandonment Expense and Impairment of Unproved Properties. In 2015, we recorded $7.6 million attributable to leases that expired during the year or were expected to expire in the future. In 2014, we recorded impairment expense of $20.0 million, of which $13.8 million was attributable to an impairment of unproved properties and $6.2 million was attributable to leases that expired during the year or were expected to expire in the future.

Contract Termination and Rig Stacking. In light of the low commodity price environment, we curtailed drilling activity in 2015. As a result, we incurred drilling and rig termination fees of $2.4 million in 2015 as compared to no drilling and rig termination fees in 2014.

General and Administrative Expenses. G&A expenses decreased 55%, or $17.5 million, primarily due to $12.4 million of incentive compensation recorded in 2014 due to the achievement of certain performance criteria associated with CRP's incentive units. Additionally, the decrease is the result of no longer having two distinct management teams and employees associated with each of CRP and Celero along with our growing capital program and oil production levels.

Gain (Loss) on Sale of Oil and Natural Gas Properties. In 2015, we recorded a net gain of $2.4 million, primarily attributable to the sale of non-core unproved property to an unrelated third party. In 2014, we recorded a net loss of $2.1 million, primarily attributable to the CO2 Project Disposition.

Other Income and Expenses. The following table summarizes our other income and expenses for the years indicated:

	Predecessor			
	Year Ended December 31,		Increase/(Decrease)	
(in thousands)	**2015**	**2014**	**$**	**%**
Other (expense) income:				
Interest expense	$ (6,266)	$ (2,475)	$ (3,791)	153 %
Gain on derivative instruments	20,756	41,943	(21,187)	(51)%
Other income	20	281	(261)	NM
Total other income	$ 14,510	$ 39,749	$ (25,239)	(63)%
Income tax benefit (expense)	$ 572	$ (1,524)	NM	NM

Interest Expense. Interest expense increased $3.8 million, or 153%, primarily due to an increase in the average amounts outstanding under our term loan and revolving credit facility in 2015 compared to 2014.

Gain on Derivative Instruments. In 2015, we recognized a $20.8 million gain on derivative instruments compared to a $41.9 million gain on derivative instruments in 2014. Net gains on our derivatives are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments.

Income Tax Benefit (Expense). We are treated as a flow-through entity for U.S. federal income tax purposes and the purposes of certain state and local income taxes and, accordingly, are not subject to such income taxes. We are subject to the Texas franchise tax, at a statutory rate of 0.75% of income. For the year ended December 31, 2015, we recognized a tax benefit of $0.6 million associated with our Texas franchise tax obligation. For the year ended December 31, 2014, we recognized income tax expense of $1.5 million. The decrease was primarily due to a decrease in the Texas franchise tax rate and a decrease in our estimated income attributable to Texas franchise tax year-over-year.

Liquidity and Capital Resources

Overview

Our development and acquisition activities require us to make significant operating and capital expenditures. Historically, our primary sources of liquidity have been capital contributions from CRP's equity sponsors, borrowings under CRP's revolving credit facility and term loan, proceeds from asset dispositions and cash flows from operations.

The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of acquisition opportunities, our cash flows from operating, investing and financing activities, and our ability to assimilate acquisitions and execute our drilling program. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

Based upon current oil and natural gas price expectations for 2017, we believe that our cash on hand, cash flow from operations and borrowings under CRP's revolving credit facility will provide us with sufficient liquidity to execute our current capital program. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot ensure that operations and other needed capital will be available on acceptable terms or at all. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot ensure that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

We plan to monitor crude oil and natural gas markets and macroeconomic events impacting their prices. Under this strategy we will opportunistically enter into hedging arrangements to reduce our exposure to commodity prices and the resulting impact of this volatility on our cash flow from operations.

Capital Budget

The following table summarizes our fiscal year 2017 capital expenditure guidance range:

(in millions)			
Capital expenditure program	$500	—	$585
Drilling and completion capital expenditure	440	—	500
Land	50	—	70
Facilities, seismic and other	10	—	15

Because we are the operator of a high percentage of our acreage, the amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations. In addition, we may be required to reclassify some portion of our reserves currently booked as proved undeveloped reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

Working Capital Analysis

Our working capital, which we define as current assets minus current liabilities, was a surplus of $59.9 million and $12.0 million at December 31, 2016 (Successor) and December 31, 2015 (Predecessor), respectively. Our cash balances totaled $134.1 million and $1.8 million at December 31, 2016 (Successor) and December 31, 2015 (Predecessor), respectively. Due to the amounts that accrue related to our drilling program, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our credit agreement will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
(in thousands)			2015	2014
Net cash provided by operating activities	$ 9,410	$ 51,740	$ 68,882	$ 97,248
Net cash used in investing activities	(1,749,733)	(101,434)	(198,635)	(163,380)
Net cash provided by financing activities	1,874,268	47,926	118,504	36,966

Operating Activities

For the period from October 11, 2016, through December 31, 2016 (Successor), net cash provided by operating activities was approximately $9.4 million. Cash provided by operating activities for the period from January 1, 2016, through October 10, 2016 (Predecessor), was approximately $51.7 million, compared to approximately $68.9 million for the year ended December 31, 2015 (Predecessor). The decrease in net cash provided by operating activities was primarily due to a $21.3 million decrease in total revenues and a decrease in net cash received for derivative settlements of $18.9 million. These decreases were offset by an increase in changes in current assets and current liabilities.

Cash provided by operating activities for the year ended December 31, 2015 (Predecessor) was approximately $68.9 million, compared to approximately $97.2 million for the year ended December 31, 2014 (Predecessor). The decrease in net cash provided by operating activities was primarily due to a $41.4 million decrease in total revenues and a decrease in changes in current assets and current liabilities, which decreased cash proceeds provided by operating activities by $16.4 million. The decreases are primarily offset by an increase in net cash received for derivative settlements of $30.9 million.

Investing Activities

The following table provides a comparative summary of cash flow from investing activities:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
(in thousands)			2015	2014
Cash flows from investing activities:				
Proceeds withdrawn from trust account	$ 500,561	$ —	$ —	$ —
Acquisition of Centennial Resource Production, LLC	(1,375,744)	—	—	—
Acquisition of oil and natural gas properties	(849,642)	(55,564)	(43,223)	(22,167)
Development of oil and natural gas properties	(24,107)	(45,605)	(156,006)	(275,683)
Purchases of other property and equipment	(801)	(265)	(2,097)	(453)
Development of assets held for sale	—	—	—	(14,240)
Proceeds from sales of oil and natural gas properties and other assets	—	—	2,691	72,382
Proceeds from sale of Atlantic Midstream, net of cash sold	—	—	—	71,781
Cash held in escrow	—	—	—	5,000
Net cash used by investing activities	$ (1,749,733)	$ (101,434)	$ (198,635)	$ (163,380)

Net cash used by investing activities is primarily comprised of acquisition and development of oil and natural gas properties, net of dispositions.

Net cash used by investing activities for the period from October 11, 2016, through December 31, 2016 (Successor) was approximately $1.7 billion and included $1.4 billion attributable to the Business Combination, $849.6 million attributable to the Silverback Acquisition and $24.1 million attributable to the development of oil and natural gas properties. Cash used by investing activities during the period was offset by $500.6 million of proceeds withdrawn from the trust account used to purchase CRP.

Net cash used by investing activities for the period from January 1, 2016, through October 10, 2016 (Predecessor) included $101.2 million attributable to the acquisition and development of oil and natural gas properties.

Net cash used by investing activities for the year ended December 31, 2015 (Predecessor) included $199.2 million attributable to the acquisition and development of oil and natural gas properties, offset by proceeds from asset sales of $2.7 million.

Net cash used by investing activities for the year ended December 31, 2014 (Predecessor) included $297.9 million attributable to the acquisition and development of oil and natural gas properties, offset by net proceeds from asset sales of $144.2 million.

Financing Activities.

Net cash provided by financing activities for the period from October 11, 2016, through December 31, 2016 (Successor), included proceeds of $1.5 billion from the issuance and sale of shares of our Class A Common Stock and $379.5 million from the issuance and sale of shares of our Series B Preferred Stock, offset by $27.1 million attributable to the payment of underwriting fees and $17.5 million repayment of deferred underwriting fees attributable to our IPO.

Net cash provided by financing activities for the period from January 1, 2016, through October 10, 2016 (Predecessor), included $55.0 million of borrowings under CRP's revolving credit facility, offset by repayments of $5.0 million.

Net cash provided by financing activities for the year ended December 31, 2015 (Predecessor) included $92.0 million of borrowing under CRP's revolving credit facility, offset by $83.0 million of repayments and capital contributions of $111.4 million.

Net cash provided by financing activities for the year ended December 31, 2014 (Predecessor) included $196.0 million of borrowing under CRP's revolving credit facility, offset by $160.0 million of repayments, $65.0 million of proceeds from CRP's term loan, and capital contributions of $59.8 million, offset by $119.3 million attributable to the repurchase of equity interests.

Credit Agreement

In connection with the consummation of the Business Combination, all indebtedness under CRP’s term loan and revolving credit facility was repaid in full. On October 11, 2016, CRP entered into a second amendment to the amended and restated credit agreement (the “second amendment”), which amends the amended and restated credit agreement, dated as of October 15, 2014, among CRP, each of the lenders from time to time party thereto and JPMorgan Chase Bank, N.A. as administrative agent (the “credit agreement”). CRP entered into the second amendment to, among other things, (i) permit the Business Combination, (ii) reflect the repayment in full of all term loans thereunder, (iii) increase the borrowing base from $140.0 million to $200.0 million, (iv) increase the interest rate to LIBOR plus 225 to 325 basis points, and (v) require CRP to have sufficient liquidity and satisfy a maximum leverage ratio in order to make dividends.

On December 28, 2016, in connection with the closing of the Silverback Acquisition, CRP entered into a third amendment to amended and restated credit agreement (the “third amendment”), which further amends the credit agreement. CRP entered into this amendment to, among other things, increase the borrowing base thereunder from $200.0 million to $250.0 million.

As of December 31, 2016, there were no borrowings under the revolving credit facility. Outstanding letters of credit were $0.4 million, leaving $249.6 million in borrowing capacity under the revolving credit facility.

The amount available to be borrowed under CRP's revolving credit facility is subject to a borrowing base that will be redetermined semiannually each April 1 and October 1 by the lenders in their sole discretion. CRP's credit agreement also allows for two optional borrowing base redeterminations on January 1 and July 1. The borrowing base depends on, among other things, the volumes of CRP's proved oil and natural gas reserves and estimated cash flows from these reserves and its commodity hedge positions. The borrowing base will automatically be decreased by an amount equal to 25% of the aggregate notional amount of issued permitted senior unsecured notes unless such decrease is waived by the lenders. Upon a redetermination of the borrowing base, if borrowings in excess of the revised borrowing capacity are outstanding, CRP could be required to immediately repay a portion of its debt outstanding under its credit agreement. The next regular redetermination date is scheduled for the spring of 2017.

Borrowings under its revolving credit facility may be base rate loans or LIBOR loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for LIBOR loans. LIBOR loans bear interest at LIBOR (adjusted for statutory reserve requirements) plus an applicable margin ranging from 225 to 325 basis points, depending on the percentage of the borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points, plus an applicable margin ranging from 125 to 225 basis points, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee on unused amounts of its revolving credit facility of 50 basis points. CRP may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

CRP’s credit agreement contains restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- make investments and loans;
- enter into mergers;
- make or declare dividends;
- enter into commodity hedges exceeding a specified percentage of our expected production;
- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness;
- incur liens;
- sell assets; and
- engage in transactions with affiliates.

Our credit agreement also requires us to maintain compliance with the following financial ratios:

- a current ratio, which is the ratio of CRP’s consolidated current assets (including unused commitments under CRP’s revolving credit facility and excluding non-cash assets under Financial Accounting Standards Board (“FASB”) Accounting Standard Codification (“ASC”) Topic 815, *Derivatives and Hedging* (“ASC 815”) and certain restricted cash) to consolidated current liabilities (excluding the current portion of long-term debt under CRP’s credit agreement and non-cash liabilities under ASC 815), of not less than 1.0 to 1.0; and

- a leverage ratio, which is the ratio of Total Funded Debt (as defined in our credit agreement) to consolidated EBITDAX (as defined in our credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0.

As of December 31, 2016, we were in compliance with such covenants and the financial ratios described above.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2016, we had no off-balance sheet arrangements.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2016 is provided in the following table:

(in thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Drilling rig commitments	$ 7,316	$ —	$ —	$ —	$ —	$ —	$ 7,316
Office and equipment leases	831	814	573	134	79	—	2,431
Asset retirement obligations(1)	—	—	—	—	—	7,226	7,226
Total	$ 8,147	$ 814	$ 573	$ 134	$ 79	$ 7,226	$ 16,973

(1) Amounts represent estimates of our future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

Recently Issued Accounting Standards

Please refer to *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, in Part II, Item 8. Financial Statements and Supplementary Data in this annual report for a discussion of recently issued accounting standards and their anticipated effect on our business.

Critical Accounting Policies and Estimate

The discussion and analysis of our financial condition and results of operations are based upon our consolidated and combined financial statements, which have been prepared in accordance with GAAP. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, in Part II, Item 8. Financial Statements and Supplementary Data in this annual report.

We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Our oil and natural gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method, we capitalize lease acquisition costs, all development costs and successful exploration costs.

Proved Oil and Natural Gas Properties. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil, natural gas and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells and service wells, including unsuccessful development wells, are capitalized.

Unproved Properties. Acquisition costs associated with the acquisition of non-producing leaseholds are recorded as unproved leasehold costs and capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease in addition to options to lease, broker fees, recording fees and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered, at which time related costs are transferred to proved oil and natural gas properties.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures, other geological and geophysical costs, and lease rentals. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending determination of whether the well has discovered proved commercial reserves. If the exploratory well is determined to be unsuccessful, the cost of the well is transferred to expense.

Impairment of Oil and Natural Gas Properties

Our proved oil and natural gas properties are recorded at cost. We evaluate our proved properties for impairment when events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future operating and capital expenditures, and discount rates.

Unproved properties costs consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves. We evaluate significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage.

Oil and Natural Gas Reserve Quantities

Our estimated proved reserve quantities and future net cash flows are critical to the understanding of the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our consolidated and combined financial statements, including the calculations of depletion and impairment of proved oil and natural gas properties. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10 percent discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We engage Netherland, Sewell & Associates, Inc., our independent petroleum engineer, to prepare our total calculated proved reserve PV-10. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with GAAP for the impact of additions and dispositions.

Revenue Recognition

Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in the above analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month, we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, contractual arrangements, NYMEX and local spot market prices and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received.

Derivative Instruments

We utilize commodity derivative instruments, including swaps, collars and basis swaps, to manage the price risk associated with the forecasted sale of our oil and natural gas production. Our derivative instruments are not designated as hedges for accounting purposes. Accordingly, changes in fair value are recognized in our consolidated and combined statements of operations in the period of change. Gains and losses on derivatives and premiums paid for put options are included in cash flows from operating activities.

Asset Retirement Obligations

Our asset retirement obligation represents the estimated present value of the amount we will incur to retire long-lived assets at the end of their productive lives, in accordance with applicable state laws. Our asset retirement obligation is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of inception with an offsetting increase in the carrying amount of the related long-lived asset. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset.

Our asset retirement liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire our wells may vary significantly from prior estimates.

Non-GAAP Financial Measure

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated and combined financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization and accretion of asset retirement obligations, exploration costs, abandonment expense and impairment of unproved properties, (gains) losses on derivatives excluding net cash receipts (payments) on settled derivatives, non-cash equity based compensation, gains and losses from the sale of assets, transaction costs and other non-cash and non-recurring operating items. Adjusted EBITDAX is not a measure of net income as determined by GAAP.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDAX to net income, our most directly comparable financial measure calculated and presented in accordance with GAAP.

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
(in thousands)			**2015**	**2014**
Adjusted EBITDAX reconciliation to net income:				
Net (loss) income attributable to Centennial Resource Development, Inc.	$ (8,081)	$ (218,724)	$ (38,325)	$ 17,790
Less net loss attributable to noncontrolling interest	904	—	—	2
Interest expense	378	5,626	6,266	2,475
Income tax (benefit) expense	—	(406)	(572)	1,524
Depreciation, depletion and amortization and accretion of asset retirement obligations	14,877	62,964	90,084	69,110
Abandonment expense and impairment of unproved properties	—	2,545	7,619	20,025
Exploration	844	—	84	—
Loss (gain) on derivatives	1,548	6,838	(20,756)	(41,943)
Net cash receipts on settled derivatives	1,054	16,623	36,430	4,611
Incentive unit compensation	—	165,394	—	—
Equity based compensation expense	1,333	—	—	12,420
Contract termination and rig stacking	—	—	2,387	—
Write-off of IPO related offering costs	—	1,181	1,585	—
Transaction costs	4,097	15,792	3	670
Gain (loss) on sale of assets	(24)	(11)	(2,439)	2,096
Adjusted EBITDAX	$ 16,930	$ 57,822	$ 82,366	$ 88,780

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about its potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGLs production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. During the period from January 1, 2014 through December 31, 2016, the WTI spot price have declined from a high of $107.95 per Bbl on June 20, 2014 to $26.19 per Bbl on February 11, 2016. NGL prices generally correlate to the price of oil, and accordingly prices for these products have likewise declined and are likely to continue following that market. Prices for domestic natural gas began to decline during the third quarter of 2014 and have continued to be weak throughout 2015 and thus far in 2016. During the period from January 1, 2014 through December 31, 2016, natural gas prices have declined from a high of $8.15 per MMBtu on February 10, 2014 to a low of $1.49 per MMBtu on March 4, 2016.

A $1.00 per barrel change in our realized oil price would have resulted in a $0.5 million and a $1.6 million change in oil revenues for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), respectively. A $0.10 per Mcf change in our realized natural gas price would have resulted in a $0.1 million and a $0.3 million change in our natural gas revenues for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), respectively. A $1.00 per barrel change in our realized NGL prices would have resulted in a $0.1 million and a $0.3 million change in NGL revenues for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor), respectively. For the period from October 11, 2016, through December 31, 2016 (Successor), oil sales, natural gas sales and NGL sales contributed 82%, 12%, and 7%, respectively, of our total revenues. For the period from January 1, 2016, through October 10, 2016 (Predecessor), oil sales, natural gas sales and NGL sales contributed 87%, 9% and 5%, respectively, of our total revenues.

Due to this volatility, we have historically used, and we expect to continue to selectively use, commodity derivative instruments, such as collars, swaps and basis swaps, to hedge price risk associated with a portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in oil and natural gas prices and provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil and natural gas prices and may partially limit our potential gains from future increases in prices. Our credit agreement limits our ability to enter into commodity hedges covering greater than 80% of our reasonably anticipated projected production volume.

Our open positions as of December 31, 2016:

Description & Production Period	Volume (Bbl)	Weighted Average Swap Price ($/Bbl) (1)	
Crude Oil Swaps:			
January 2017 - December 2017	91,250	$	64.05
January 2017 - December 2017	36,500		54.65
January 2017 - December 2017	36,500		43.50
January 2017 - December 2017	36,500		44.85
January 2017 - December 2017	36,500		45.10
January 2017 - December 2017	109,500		44.80
January 2017 - December 2017	36,500		47.27
January 2017 - December 2017	36,500		49.00
January 2017 - December 2017	182,500		49.80
January 2017 - December 2017	73,000		52.35
January 2018 - December 2018	36,500		55.95
Crude Oil Basis Swaps:			
January 2017 - November 2017	91,250	$	(0.20)
January 2017 - November 2017	36,500		(0.20)

(1) The oil swap contracts are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude. The oil basis derivative contracts are settled based on the difference between the arithmetic average of WTI MIDLAND ARGUS and WTI ARGUS during the relevant calculation period.

Description & Production Period	Volume (MMBtu)	Weighted Average Swap Price ($/MMBtu) (1)
Natural Gas Swaps:		
January 2017 - December 2017	1,460,000	$ 2.94

(1) The natural gas derivative contracts are settled based on the month's average daily NYMEX price of Henry Hub Natural Gas.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparties to our derivative contracts currently in place have investment grade ratings.

Our principal exposures to credit risk are through receivables resulting from joint interest receivables and receivables from the sale of our oil and natural gas production due to the concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit quality of our customers is high.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

Interest is calculated under the terms of our credit agreement based on a LIBOR spread. At December 31, 2016, we had no outstanding debt. However, if our entire credit facility borrowing base of $250.0 million was outstanding at December 31, 2016, a 1.0% increase in interest rates would result in an increase in annual interest expense of approximately $2.5 million, assuming the $250.0 million of debt was outstanding for the full year. We do not currently have or intend to enter into any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CENTENNIAL RESOURCE DEVELOPMENT, INC.
INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Centennial Resource Development, Inc.:

We have audited the accompanying consolidated balance sheets of Centennial Resource Development, Inc. and its subsidiaries (the Company) as of December 31, 2016 (Successor Company balance sheet) and 2015 (Predecessor Company balance sheet), and the related consolidated statements of operations, shareholders' equity, and cash flows for the period from October 11, 2016 through December 31, 2016 (Successor Company operations) and the period from January 1, 2016 through October 10, 2016 and for each of the two years in the period ended December 31, 2015 (Predecessor Company operations). These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the Successor Company consolidated financial statements referred to above present fairly, in all material respects, the financial position of Centennial Resource Development, Inc. and its subsidiaries as of December 31, 2016, and the results of their operations and their cash flows for the period from October 11, 2016 through December 31, 2016, in conformity with U.S. generally accepted accounting principles.

Further, in our opinion, the Predecessor Company consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of the predecessor to Centennial Resource Development, Inc. and its subsidiaries as of December 31, 2015, and the results of their operations and their cash flows for the period from January 1, 2016 through October 10, 2016, and for each of the two years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Denver, Colorado
March 23, 2017

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED BALANCE SHEETS
(in thousands)

	Successor	Predecessor
	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 134,083	$ 1,768
Accounts receivable, net	14,734	13,012
Derivative instruments, net	431	19,043
Prepaid and other current assets	2,078	322
Total current assets	151,326	34,145
Oil and natural gas properties, other property and equipment		
Oil and natural gas properties, successful efforts method	605,853	651,596
Accumulated depreciation, depletion and amortization	(14,436)	(180,946)
Unproved oil and natural gas properties	1,905,661	105,897
Other property and equipment, net of accumulated depreciation of $391 and $868, respectively	2,193	2,240
Total property and equipment, net	2,499,271	578,787
Noncurrent assets		
Derivative instruments, net	—	2,070
Other noncurrent assets	1,045	1,293
Total assets	$ 2,651,642	$ 616,295
LIABILITIES AND SHAREHOLDERS'/OWNERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 86,100	$ 19,985
Derivative instruments, net	5,361	—
Other current liabilities	—	2,148
Total current liabilities	91,461	22,133
Noncurrent liabilities		
Revolving credit facility	—	74,000
Term loan, net of unamortized deferred financing costs	—	64,649
Asset retirement obligations	7,226	2,288
Deferred tax liability	—	2,361
Derivative instruments, net	20	—
Total liabilities	98,707	165,431
Shareholders'/Owners' Equity		
Owners' equity	—	450,864
Preferred stock, $.0001 par value, 1,000,000 shares authorized:		
Series A: 1 share issued and outstanding at December 31, 2016	—	—
Series B: 104,400 shares issued and outstanding at December 31, 2016	—	—
Common stock, $0.0001 par value, 620,000,000 shares authorized:		
Class A: 201,091,646 shares issued and outstanding at December 31, 2016	20	—
Class C: 19,155,921 shares issued and outstanding at December 31, 2016	2	—
Additional paid-in capital	2,364,049	—
Accumulated deficit	(8,929)	—
Total shareholders'/owners' equity	2,355,142	450,864
Noncontrolling interest	197,793	—
Total equity	2,552,935	450,864
Total liabilities and shareholders'/owners' equity	$ 2,651,642	$ 616,295

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues				
Oil sales	$ 24,313	$ 59,787	$ 77,643	$ 114,955
Natural gas sales	3,449	6,045	7,965	9,670
NGL sales	1,955	3,284	4,852	7,200
Total revenues	29,717	69,116	90,460	131,825
Operating expenses				
Lease operating expenses	3,541	11,036	21,173	17,690
Severance and ad valorem taxes	1,636	3,696	5,021	6,875
Transportation, processing, gathering and other operating expense	2,187	4,583	5,732	4,772
Depreciation, depletion, amortization and accretion of asset retirement obligations	14,877	62,964	90,084	69,110
Abandonment expense and impairment of unproved properties	—	2,545	7,619	20,025
Exploration	844	—	84	—
Contract termination and rig stacking	—	—	2,387	—
General and administrative expenses	13,715	25,581	14,206	31,694
Incentive unit compensation	—	165,394	—	—
Total operating expenses	36,800	275,799	146,306	150,166
Gain (loss) on sale of oil and natural gas properties	24	11	2,439	(2,096)
Total operating loss	(7,059)	(206,672)	(53,407)	(20,437)
Other (expense) income				
Interest expense	(378)	(5,626)	(6,266)	(2,475)
Gain (loss) on derivative instruments	(1,548)	(6,838)	20,756	41,943
Other (expense) income	—	6	20	281
Total other (expense) income	(1,926)	(12,458)	14,510	39,749
(Loss) income before income taxes	(8,985)	(219,130)	(38,897)	19,312
Income tax benefit (expense)	—	406	572	(1,524)
Net (loss) income	(8,985)	(218,724)	(38,325)	17,788
Less net loss attributable to noncontrolling interest	(904)	—	—	(2)
Net (loss) income attributable to Centennial Resource Development, Inc.	$ (8,081)	$ (218,724)	$ (38,325)	$ 17,790
Loss per share:				
Basic	$ (0.05)			
Diluted	$ (0.05)			

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED AND COMBINED STATEMENTS OF CHANGES IN OWNERS' EQUITY (Predecessor)
(in thousands)

	Total owners' equity	Noncontrolling interest in subsidiary	Total equity
Balance at December 31, 2013	$ 389,859	$ 688	$ 390,547
Contributions	59,776	150	59,926
Repurchase of equity interests	(119,272)	—	(119,272)
Deemed contribution from sale of assets	21,489	(836)	20,653
Deemed contribution from parent for payment of incentive units	12,420	—	12,420
Deemed distribution in connection with common control acquisition	(4,130)	—	(4,130)
Net income (loss)	17,790	(2)	17,788
Balance at December 31, 2014	377,932	—	377,932
Contributions	111,396	—	111,396
Deemed distribution from sale of assets	(139)	—	(139)
Net loss	(38,325)	—	(38,325)
Balance at December 31, 2015	450,864	—	450,864
Deemed contributions	179,442	—	179,442
Net loss	(218,724)	—	(218,724)
Balance at October 10, 2016	$ 411,582	$ —	$ 411,582

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED STATEMENT OF SHAREHOLDERS’ EQUITY (Successor)
(in thousands)

	Common Stock						Preferred Stock								
	Class A		Class B		Class C		Series A		Series B						
	Shares	Amount	Shares	Amount	Shares	Amount	Shares	Amount	Shares	Amount	Paid-In Capital	Accumulated Deficit	Total Equity	Noncontrolling Interest	Total Equity
Balance at October 10, 2016	2,175	$ —	12,500	$ 1	—	$ —	—	$ —	—	$ —	$ 5,460	$ (461)	$ 5,000	$ —	$ 5,000
Conversion of common shares from Class B to Class A at transaction	12,500	1	(12,500)	(1)	—	—	—	—	—	—	—	—	—	—	—
Class A common shares released from possible redemption	47,825	5	—	—	—	—	—	—	—	—	478,243	—	478,248	—	478,248
Class C common shares issued	—	—	—	—	20,000	2	—	—	—	—	(2)	—	—	—	—
Conversion of common shares from Class C to Class A	844	—	—	—	(844)	—	—	—	—	—	7,798	—	7,798	(7,798)	—
Sale of unregistered Class A common shares	101,005	10	—	—	—	—	—	—	—	—	1,010,040	—	1,010,050	—	1,010,050
Underwriters’ discount and offering expense	—	—	—	—	—	—	—	—	—	—	(6,713)	—	(6,713)	—	(6,713)
Net loss	—	—	—	—	—	—	—	—	—	—	—	(387)	(387)	—	(387)
Noncontrolling interest in Centennial Resource Production, LLC	—	—	—	—	—	—	—	—	—	—	—	—	—	184,779	184,779
Balance at October 11, 2016	164,349	16	—	—	19,156	2	—	—	—	—	1,494,826	(848)	1,493,996	176,981	1,670,977
Restricted stock issued	257	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sale of unregistered Class A common shares	36,486	4	—	—	—	—	—	—	—	—	530,503	—	530,507	—	530,507
Sale of unregistered Class B preferred shares	—	—	—	—	—	—	—	—	104	—	379,494	—	379,494	—	379,494
Underwriters’ discount and offering expense	—	—	—	—	—	—	—	—	—	—	(20,391)	—	(20,391)	—	(20,391)
Change in equity due to issuance of shares by Centennial Resource Production, LLC	—	—	—	—	—	—	—	—	—	—	(21,716)	—	(21,716)	21,716	—
Equity based compensation	—	—	—	—	—	—	—	—	—	—	1,333	—	1,333	—	1,333
Net loss	—	—	—	—	—	—	—	—	—	—	—	(8,081)	(8,081)	(904)	(8,985)
Balance at December 31, 2016	201,092	$ 20	—	$ —	19,156	$ 2	—	$ —	104	$ —	$ 2,364,049	$ (8,929)	$ 2,355,142	$ 197,793	$ 2,552,935

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS
(in thousands)

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash flows from operating activities:				
Net (loss) income	$ (8,985)	$ (218,724)	$ (38,325)	$ 17,788
Adjustments to reconcile net loss to net cash provided by operating activities:				
Accretion of asset retirement obligations	49	134	139	156
Depreciation, depletion and amortization	14,828	62,830	89,945	68,954
Incentive unit compensation	—	165,394	—	—
Equity based compensation expense	1,333	—	—	12,420
Noncash transaction costs	—	14,049	—	—
Abandonment expense and impairment of unproved properties	—	2,545	7,619	20,025
Write-off of deferred S-1 related expense	—	—	1,585	—
Deferred tax (benefit) expense	—	(406)	(572)	1,524
(Gain) loss on sale of oil and natural gas properties	(24)	(11)	(2,439)	2,096
Loss (gain) on derivative instruments	1,548	6,838	(20,756)	(41,943)
Net cash received for derivative settlements	1,054	16,623	35,493	4,611
Recovery of bad debt	—	—	—	(777)
Amortization of debt issuance costs	70	376	482	316
Changes in operating assets and liabilities:				
Decrease (increase) in accounts receivable	(983)	969	5,244	(6,322)
Increase in prepaid and other assets	(1,092)	(170)	(864)	(79)
Increase (decrease) in accounts payable and other liabilities	1,612	1,293	(8,669)	18,479
Net cash provided by operating activities	9,410	51,740	68,882	97,248
Cash flows from investing activities:				
Proceeds withdrawn from trust account	500,561	—	—	—
Acquisition of Centennial Resource Production, LLC	(1,375,744)	—	—	—
Acquisition of oil and natural gas properties	(849,642)	(55,564)	(43,223)	(22,167)
Development of oil and natural gas properties	(24,107)	(45,605)	(156,006)	(275,683)
Purchases of other property and equipment	(801)	(265)	(2,097)	(453)
Development of assets held for sale	—	—	—	(14,240)
Proceeds from sales of oil and natural gas properties and other assets	—	—	2,691	72,382
Proceeds from sale of Atlantic Midstream, net of cash sold	—	—	—	71,781
Cash held in escrow	—	—	—	5,000
Net cash used by investing activities	(1,749,733)	(101,434)	(198,635)	(163,380)
Cash flows from financing activities:				
Issuance of Class A common shares	1,540,556	—	—	—
Issuance of Preferred Series B shares	379,494	—	—	—
Payment of underwriting fees	(27,104)	—	—	—
Payment of deferred underwriting compensation	(17,500)	—	—	—
Proceeds from revolving credit facility	—	55,000	92,000	196,000
Repayment of revolving credit facility	—	(5,000)	(83,000)	(160,000)
Capital contributions	—	—	111,396	59,776
Financing obligation	(63)	(2,074)	(1,633)	—
Debt issuance costs	(1,115)	—	(259)	(1,637)
Repurchase of equity	—	—	—	(119,272)
Proceeds from term loan	—	—	—	65,000
Distribution in connection with common control acquisition	—	—	—	(3,051)
Contributions received from noncontrolling interest	—	—	—	150
Net cash provided by financing activities	1,874,268	47,926	118,504	36,966
Net increase (decrease) in cash and cash equivalents	133,945	(1,768)	(11,249)	(29,166)
Cash and cash equivalents, beginning of period	138	1,768	13,017	42,183
Cash and cash equivalents, end of period	$ 134,083	$ —	$ 1,768	$ 13,017

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS (Continued)
(in thousands)

Supplemental cash flow information and noncash activity:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Supplemental cash flow information				
Cash paid for interest	$ 234	$ 5,092	$ 5,782	$ 1,935
Supplemental noncash activity				
Accrued capital expenditures included in accounts payable and accrued expenses	$ 65,217	$ 21,025	$ 13,124	$ 81,510
Financing obligation	—	—	3,770	—

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

Note 1—Basis of Presentation and Summary of Significant Accounting Policies

Description of Business

Centennial Resource Development, Inc. (the “Company”) was originally incorporated in Delaware on November 4, 2015 as a special purpose acquisition company under the name Silver Run Acquisition Corporation for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving the Company and one or more businesses.

On February 29, 2016, the Company consummated its initial public offering of Units each consisting of one share of Class A Common Stock and one-third of one Public Warrant. On October 11, 2016, the Company consummated the acquisition of approximately 89% of the outstanding membership interests in Centennial Resource Production, LLC, a Delaware limited liability company (“CRP” and such acquisition, the “Business Combination”). In connection with the closing of the Business Combination, the Company changed its name from "Silver Run Acquisition Corporation" to "Centennial Resource Development, Inc." and continued the listing of its Class A Common Stock and Public Warrants on NASDAQ under the symbols "CDEV" and "CDEVW," respectively. Refer to *Note 2—Business Combination* for further discussion of the Business Combination.

CRP was formed in August 2012 by an affiliate of NGP Energy Capital Management, a family of energy-focused private equity investment funds, in connection with the acquisition of all of the oil and natural gas properties and certain other assets of Celero, which was formed in 2006 to focus on the development and acquisition of oil and natural gas properties in Texas and New Mexico, primarily in the Permian Basin in West Texas. Until the closing of the Business Combination, CRP operated as a privately-held independent oil and natural gas company.

The Company’s Class A Common Stock and Public Warrants trade on The NASDAQ Capital Market (“NASDAQ”) under the ticker symbols “CDEV” and “CDEVW,” respectively. The Units automatically separated into their component securities prior to or upon closing of the Business Combination and, as a result, no longer trade as a separate security. The consolidated financial statements include the accounts of the Company and CRP and its wholly-owned subsidiaries.

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying consolidated and combined financial statements. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2016, through the filing date of this report.

As a result of the Business Combination, the Company is the acquirer for accounting purposes, and CRP is the acquiree and accounting Predecessor. The Company’s financial statement presentation distinguishes a “Predecessor” for CRP for periods prior to the Business Combination. The Company is the “Successor” for periods after the Business Combination, which includes consolidation of CRP subsequent to the Business Combination on October 11, 2016. The Merger was accounted for as a business combination using the acquisition method of accounting, and the Successor financial statements reflect a new basis of accounting that is based on the fair value of the net assets acquired. Refer to *Note 2—Business Combination* for further discussion of the Business Combination. As a result of the application of the acquisition method of accounting as of the Business Combination, the financial statements for the Predecessor period and for the Successor period are presented on a different basis of accounting and are therefore, not comparable.

Principles of Consolidation

The consolidated financial statements included herein have been prepared in accordance with GAAP and the rules and regulations of Securities and Exchange Commission (“SEC”). The consolidated financial statements include the accounts of the Company and its majority owned subsidiary CRP, and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of the Company’s consolidated and combined financial statements requires the Company’s management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments and estimates include: (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) determining fair value and allocating purchase price in connection with business combinations; (6) valuation of derivative instruments; and (7) accrued revenue and related receivables.

Cash and Cash Equivalents

The Company considers all highly liquid instruments with an original maturity of three months or less at the time of issuance to be cash equivalents. The Company's cash management process provides for the daily funding of checks as they are presented to the bank.

Accounts Receivable

Accounts receivable consists mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and natural gas receivables are collected within two months and the Company has had minimal bad debts.

Although diversified among many companies, collectibility is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. The Company establishes an allowance for doubtful accounts equal to the estimable portions of accounts receivable for which failure to collect is probable. The Company had no allowance for doubtful accounts at December 31, 2016 (Successor). The allowance for doubtful accounts at December 31, 2015 (Predecessor) was $0.1 million.

Credit Risk and Other Concentrations

The Company normally sell production to a relatively small number of customers, as is customary in its business. For the year ended December 31, 2016, sales to Plains Marketing, LP (“Plains”), Shell Trading (US) Company, and Permian Transport and Trading accounted for 48%, 22%, and 11%, respectively, of the total revenue. For the years ended December 31, 2015 and December 31, 2014, the Company only had one major customer, Plains, which accounted for 64% and 78%, respectively, of total revenue. The loss of any of the Company’s major purchasers could materially and adversely affect its revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, the Company believes that the loss of any major purchaser would not have a material adverse effect on its financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. As of December 31, 2016, and through the filing date of this report, all of the Company’s derivative counterparties were members of the Company’s credit facility lender group. The credit facility is secured by the Company’s proved oil and natural gas properties and therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $0.7 million at December 31, 2016 (Successor). The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; and (ii) monitoring the creditworthiness of the Company’s counterparties on an ongoing basis. In accordance with the Company’s standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

The Company places its temporary cash investments with high-quality financial institutions and does not limit the amount of credit exposure to any one financial institution. For the years ended December 31, 2016 (Successor) and December 31, 2015 (Predecessor), the Company has not incurred losses related to these investments.

Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its oil and natural gas properties. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells and development wells are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized but are charged to expense if the well is determined to be unsuccessful. As of December 31, 2016 (Successor) and December 31, 2015 (Predecessor), no costs were capitalized in connection with exploratory wells in progress. Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to income.

Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on or otherwise attributed to the property. There was no abandonment and impairment expense for the period from October 11, 2016, through December 31, 2016 (Successor). For the period from January 1, 2016, through October 10, 2016 (Predecessor), the Company recorded abandonment and impairment expense of $2.5 million for leases which have expired, or are expected to expire. For the year ended December 31, 2015 (Predecessor), the Company recorded abandonment and impairment expense of $7.6 million for leases which have expired, or are expected to expire. For the year ended December 31, 2014 (Predecessor), the Company recorded impairment expense of $20.0 million, of which $13.8 million was attributable to an impairment of unproved properties and $6.2 million was attributable to leases which had expired, or were expected to expire.

The Company reviews it proved oil and natural gas properties for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows. There were no impairments of proved oil and natural gas properties for the periods October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor) and for the years ended December 31, 2015 (Predecessor) and December 31, 2014 (Predecessor).

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, vehicles, and computer hardware and software is recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets ranging from three to twenty years. Major renewals and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Deferred Loan Costs

Deferred loan costs related to the Company's revolving credit facility are included in the line item *Other noncurrent assets* in the consolidated balance sheets and are stated at cost, net of amortization. These costs are amortized to interest expense on a straight line basis over the borrowing term.

Derivative Financial Instruments

In order to manage its exposure to oil and natural gas price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements relating to the price risk associated with a portion of its production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. The Company's derivatives have not been designated as hedges for accounting purposes. For additional discussion on derivatives, please refer to *Note 9—Derivative Instruments*.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired. The increase in carrying value is included in proved oil and natural gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and natural gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties. For additional discussion, please refer to *Note 11—Asset Retirement Obligations*.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company follows the sales method of accounting for its oil and natural gas revenue, whereby revenue is recorded based on the Company's share of volume sold, regardless of whether the Company has taken its proportional share of volume produced. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. The Company had no significant imbalances as of December 31, 2016 or 2015.

Income Taxes

Income taxes and uncertain tax positions are accounted for in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 740, *Accounting for Income Taxes* ("ASC 740"). Deferred income taxes are provided for the differences between the bases of assets and liabilities for financial reporting and income tax purposes. Tax positions meeting the more-likely-than-not recognition threshold are measured pursuant to the guidance set forth in ASC 740. A valuation allowance is established when necessary to reduce deferred tax assets to the amount expected to be realized.

Equity Based Compensation (Successor)

The Company recognizes compensation related to all stock-based awards, including stock options, in the financial statements based on their estimated grant-date fair value. The Company grants various types of stock-based awards including stock options and restricted stock. The fair value of stock option awards is determined using the Black-Scholes option pricing model. Service-based restricted stock are valued using the market price of the Company's common stock on the grant date. Compensation cost is recognized ratably over the applicable vesting period. See *Note 8—Equity Based Compensation* for additional information regarding the Company's equity based compensation (successor).

Equity Based Compensation (Predecessor)

Pursuant to the LLC Agreement of CRP (prior to the Business Combination), certain incentive units were available to be issued to the Company's management and employees, consisting of Tier I, Tier I A, Tier II, Tier III and Tier IV units. The incentive units were intended to be compensation for services rendered to CRP. Tier Incentive units are accounted for as liability awards under FASB ASC Topic 718, *Compensation: Stock Compensation* ("ASC 718"), with compensation expense based on period-end fair value. Refer to *Note 8—Equity Based Compensation* for additional information regarding the CRP's equity based compensation (Predecessor).

Earnings (Loss) Per Share

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Basic earnings (loss) per share is calculated by dividing earnings (loss) available to common shareholders by the weighted average shares-basic during each period.

The Company's preferred series B shares have a non-forfeitable right to participate in distributions with common stockholders on a pro rata, as-converted basis and as such are considered participating securities. Shares of the Company's unvested restricted stock are eligible to receive dividends; however, dividend rights will be forfeited if the award does not vest. Accordingly, these shares are not considered participating securities. Shares of the Company's class C common stock and warrants do not share in the earnings or losses and are therefore not participating securities.

The Company uses the "if-converted" method to determine the potential dilutive effect of exchanges of outstanding CRP Common Units and corresponding shares of its outstanding Class C common stock, and the treasury stock method to determine the potential dilutive effect of its outstanding restricted stock and stock options.

The following table reflects the allocation of net income to common stockholders and EPS computations for the periods indicated based on a weighted average number of common stock outstanding for the period:

	Successor	
(in thousands, except per share data)	October 11, 2016 through December 31, 2016	
Net income (loss)	$	(8,081)
Less: Loss allocable to participating securities		(46)
Net loss available for common shareholders	$	(8,035)
Basic net loss per share	$	(0.05)
Diluted net loss per share	$	(0.05)
Basic weighted average share outstanding		165,684
Add: Dilutive effects of stock options and RSUs		—
Diluted weighted average shares outstanding		165,684

Options and restricted shares of 2.7 million and 0.3 million, respectively, were not included in the weighted average shares-dilutive calculation for the period from October 11, 2016, through December 31, 2016 because their effect would have been anti-dilutive.

Segment Reporting

The Company operates in only one industry segment which is the exploration and production of oil and natural gas. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

Recently Issued Accounting Standards

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*. This update apples to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2017, including interim periods within those fiscal years with early adoption permitted. This update should be applied using the retrospective transition method. Adoption of this standard will only affect the presentation of the Company's cash flows and will not have a material impact on its consolidated financial statements.

In April 2016, the FASB issued ASU 2016-10, *Revenue from Contracts with Customers: Identifying Performance Obligations and Licensing*. This update clarifies two principles of ASC Topic 606, *Revenue from Contracts with Customers*: identifying performance obligations and the licensing implementation guidance. This standard has the same effective date as ASU 2016-08, *Revenue from Contracts with Customers: Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)*, the revenue recognition standard discussed below. The adoption of this standard is not expected to have a material impact on the Company's financial position, results of operations and liquidity.

March 2016, the FASB issued ASU 2016-09, *Compensation-Stock Compensation*. This update applies to all entities that issue equity-based payment awards to their employees. Under this update, there were several areas that were simplified including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years with early adoption permitted. The Company elected to early adopt this guidance in October 2016 in conjunction with the issuance of its equity awards.

In March 2016, the FASB issued ASU 2016-08, *Revenue from Contracts with Customers: Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)*. Under this update, an entity should recognize revenue to depict 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. This update will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. This update allows for either full retrospective adoption, meaning this update is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning this update is applied only to the most current period presented. The Company is currently evaluating the impact, if any, that the adoption of this update will have on its financial position, results of operations and liquidity.

In February 2016, the FASB issued ASU 2016-02, *Leases*. This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Company believes the primary impact of adopting this standard will be the recognition of assets and liabilities on its balance sheet for current operating leases.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application permitted for annual reporting period beginning after December 31, 2016. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

Subsequent Events

On March 1, 2017, the Company delivered a notice of redemption of the Public Warrants, announcing its intention to redeem any unexercised and outstanding Public Warrants on March 31, 2017 for $0.01 per Public Warrant. As permitted under the warrant agreement that provides the terms of the Public Warrants, the notice of redemption requires all holders exercising their Public Warrants prior to March 31, 2017 to do so on a “cashless basis” and surrender their Public Warrants for a number of shares of Class A Common Stock equal to the product of the quotient equal to (i) the difference between $11.50 and $18.44 (the average last sale price of the Class A Common Stock for the ten trading days ending on February 24, 2017) divided by (ii) $18.44, or approximately 0.376, multiplied by the number of Public Warrants held by such holder, rounded down to the nearest whole share. Assuming all warrants are exercised by holders, Centennial will issue approximately 6.27 million shares of Class A Common Stock to the Public Warrant holders, resulting in a share count of approximately 253 million shares outstanding, which includes Class A Common Stock shares, the shares of Series B Preferred Stock held by Riverstone (assuming conversion to Class A Common Stock on a 250-to-one basis), and the shares of Class C Common Stock held by the Centennial Contributors. The Private Placement Warrants are non-redeemable so long as they are held by our Sponsor or its permitted transferees. Refer to *Note 7—Shareholders' and Owners' Equity* for additional information regarding the Company’s warrants.

Note 2—Business Combination

On October 11, 2016 (the "Closing Date"), the Company consummated the acquisition of approximately 89% of the outstanding membership interests in Centennial Resource Production, LLC, a Delaware limited liability company ("CRP"), pursuant to (i) that certain Contribution Agreement, dated as of July 6, 2016 (as amended by Amendment No. 1 thereto, dated as of July 29, 2016, the "Contribution Agreement"), among Centennial Resource Development, LLC, a Delaware limited liability company ("CRD"), NGP Centennial Follow-On LLC, a Delaware limited liability company ("NGP Follow-On"), Celero Energy Company, LP, a Delaware limited partnership (together with CRD and NGP Follow-On, the "Centennial Contributors"), CRP and New Centennial, LLC, a Delaware limited liability company ("NewCo"), (ii) that certain Assignment Agreement, dated as of October 7, 2016, between NewCo and the Company and (iii) that certain Joinder Agreement, dated as of October 7, 2016, by the Company (such acquisition, together with the other transactions contemplated by the Contribution Agreement, the "Business Combination").

At the closing of the Business Combination (the "Closing"), Silver Run contributed to CRP approximately $1.49 billion in cash and CRP then distributed to the Centennial Contributors cash in the amount of approximately $1.19 billion in partial redemption of the Centennial Contributors' membership interests in CRP. At the Closing, Silver Run and the Centennial Contributors effected a recapitalization of CRP pursuant to which (1) all of the remaining outstanding membership interests in CRP of the Centennial Contributors were converted into 20,000,000 units representing common membership interests in CRP (the

"CRP Common Units") and (2) the Company was admitted as a member of CRP and issued 163,505,000 CRP Common Units, representing an approximate 89% interest in CRP.

The Business Combination has been accounted using the acquisition method. The acquisition method of accounting is based on FASB ASC 805, *Business Combination* ("ASC 805"), and uses the fair value concepts defined in FASB ASC 820, *Fair Value Measurements* ("ASC 820"). ASC 805 requires, among other things, that most assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date by Silver Run, who was determined to be the accounting acquirer.

The purchase consideration for the Business Combination was as follows:

(in thousands)	October 11, 2016	
Preliminary purchase consideration:		
Cash	$	1,186,744
Repayment of CRP long-term debt(1)		189,000
Total purchase price consideration		1,375,744
Fair value of non-controlling interest(2)		184,779
Total purchase price consideration and fair value of non-controlling interest	$	1,560,523

(1) Represents the additional contribution made by Silver Run to CRP in exchange for units representing common membership interest in CRP ("CRP Common Units"), to repay CRP's outstanding indebtedness at the Closing Date.

(2) Represents the fair value of the non-controlling interest (NCI) attributable to the Centennial Contributors. NCI is the portion of equity (net assets) in a subsidiary not attributable, directly or indirectly to Silver Run. In a business combination the NCI is recognized at its acquisition date fair value in accordance with ASC 805. The fair value of the NCI represents a 11% membership interest in CRP.

The following table summarizes the allocation of the purchase consideration to the assets acquired and liabilities assumed:

(in thousands)	October 11, 2016	
Fair value of assets acquired:		
Other current assets	$	13,341
Derivative instruments		1,052
Oil and gas properties(1):		
Proved properties		444,551
Unproved properties		1,138,423
Other property, plant and equipment		1,764
Goodwill		—
Total fair value of assets acquired		1,599,131
Fair value of liabilities assumed:		
Accounts payable and accrued expenses		30,156
Other current liabilities		63
Derivative instruments(2)		3,400
Asset retirement obligation		4,989
Fair value of net assets acquired	$	1,560,523

(1) The fair value measurements of oil and natural gas properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by management at the time of the valuation and are the most sensitive and may be subject to change. The reduction in the carrying cost of the proved properties was impacted by all of these factors, but most notably, the assumptions with respect to future commodity prices as of the valuation date.

(2) The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the merger and represent Level 2 inputs. Derivative instruments in an asset position include a measure of counterparty

nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of the Company's own nonperformance risk, each based on the current published credit default swap rates.

Unaudited Pro Forma Operating Results

The following unaudited pro forma combined financial information has been prepared as if the Business Combination and other related transactions had taken place on January 1, 2015. The unaudited pro forma consolidated financial information has been prepared using the acquisition method of accounting in accordance with GAAP.

The information reflects pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including depletion of CRP's fair-valued proved oil and gas properties, and the estimated tax impacts of the pro forma adjustments. Additionally, pro forma earnings for the year ended December 31, 2016, were adjusted to exclude $18.7 million of transaction-related costs and $165.4 million of incentive unit compensation incurred by CRP.

The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Business Combination taken place on January 1, 2015; furthermore, the financial information is not intended to be a projection of future results.

	(Unaudited Pro Forma)	
	Year Ended December 31,	
(in thousands)	2016	2015
Total revenues	$ 98,833	$ 90,460
Total operating expenses	86,490	123,702
Net income (loss) attributable to common shareholders of Centennial Resource Development, Inc.	1,666	(6,397)
Basic and diluted net loss per share	0.01	(0.04)

Note 3—Property Acquisitions and Dispositions

2016 Acquisitions

In December 2016, the Company acquired undeveloped acreage and oil and gas producing properties located in Reeves County, Texas from Silverback Exploration, LLC. for an aggregate price of approximately $855.0 million, subject to customary purchase price adjustments. Approximately $116.7 million was recorded as proved oil and natural gas properties with the remaining recorded to unproved oil and natural gas properties. Approximately $32.3 million of the purchase price is included in accounts payable on the consolidated balance sheet as of December 31, 2016. This remaining amount will be paid when all the title issues related to the acquisition have been satisfied. The assets include 31 operated producing horizontal wells and approximately 35,500 net acres that directly offset the Company's existing acreage in Reeves County, Texas. Of the net acres acquired, 1,250 net acres are subject to consents to assign, which are expected to be assigned in the first quarter of 2017. The Company operates approximately 90% of, and has an approximate 90% working interest in, this acreage. The Wolfcamp A and Wolfcamp C are producing horizons on this acreage and the Company believes that this acreage may be prospective for the Wolfcamp C and Avalon and Bone Spring shale formations.

In June 2016, the Company acquired undeveloped acreage and oil and gas producing properties located in Reeves County, Texas. Total cash consideration paid by the Company was $33.0 million, including usual and customary post-closing adjustments. Approximately $15.4 million was recorded as proved oil and natural gas properties. The assets include four operated producing horizontal wells and approximately 1,580 net acres that directly offset the Company's existing acreage in Reeves County, Texas.

	Predecessor
(in thousands)	June 3, 2016
Cash consideration	$ 32,979
Fair value of assets and liabilities acquired:	
Proved oil and natural gas properties	15,374
Unproved oil and natural gas properties	18,071
Total fair value of oil and natural gas properties acquired	33,445
Revenue Suspense	(400)
Asset retirement obligation	(66)
Total fair value of net assets acquired	$ 32,979

In May 2016, the Company acquired unproved acreage in close proximity to its operating area in Reeves County, Texas and wellbore only rights in an uncompleted horizontal wellbore for approximately $9.8 million from Caird DB, LLC. The assets included approximately 875 net acres that directly offset the Company's existing acreage.

2015 Acquisitions

On September 1, 2015, the Company acquired additional interests in proved and unproved oil and natural gas properties in the Delaware Basin. Total cash consideration paid by the Company was $16.0 million, net of closing adjustments.

On September 3, 2015, the Company acquired a non-operated interest in 1,804 net acres in the Delaware Basin from an unrelated third party. Total cash consideration paid by the Company was $6.4 million, net of closing adjustments.

The Company allocated the final purchase prices to the acquired assets and liabilities based on fair value as of the respective acquisition dates, as summarized in the table below.

	Predecessor	
	Acquisition #1	Acquisition #2
(in thousands)	September 1, 2015	September 3, 2015
Cash consideration	$ 16,006	$ 6,369
Fair value of assets and liabilities acquired:		
Proved oil and natural gas properties	7,731	6,491
Unproved oil and natural gas properties	8,312	—
Total fair value of oil and natural gas properties acquired	16,043	6,491
Asset retirement obligation	(37)	(122)
Total fair value of net assets acquired	$ 16,006	$ 6,369

2014 Acquisitions

In June 2014, the Company acquired 2,400 net acres in the Delaware Basin from an unrelated third party, for approximately $11.0 million, net of customary closing adjustments.

2014 Dispositions

In December 2014, the Company sold its interest in approximately 1,845 net acres in Ward County, Texas, including 18 vertical wells, to an NGP-controlled entity for proceeds of $12.5 million, which resulted in a gain of $1.5 million and was recorded as an equity contribution due to the entities being under common control.

In May 2014, the Company sold its Caprock field to an unrelated third party for $59.3 million, net of customary closing adjustments. A net loss of $2.2 million was recognized on the sale during the second quarter of 2014.

In February 2014, the Company sold its 98.5% interest in Atlantic Midstream to PennTex Permian, an NGP-controlled entity for net proceeds of $71.8 million, which resulted in a gain of $20.0 million and was recorded as an equity contribution due to the entities being under common control.

Note 4—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	Successor	Predecessor
(in thousands)	December 31, 2016	December 31, 2015
Oil and natural gas	$ 11,596	$ 5,789
Joint interest billings	2,942	1,514
Hedge settlements	194	3,956
Other	2	1,844
Allowance for doubtful accounts	—	(91)
Accounts receivable, net	$ 14,734	$ 13,012

Accounts payable and accrued expenses are comprised of the following:

	Successor	Predecessor
(in thousands)	December 31, 2016	December 31, 2015
Accounts payable	$ 11,210	$ 1,827
Accrued capital expenditures	24,038	11,700
Revenues payable	3,815	3,439
Payable to Silverback	32,293	—
Accrued underwriting fees	7,719	—
Other	7,025	3,019
Accounts payable and accrued expenses	$ 86,100	$ 19,985

Note 5—Long-Term Debt

Credit Agreement (Successor)

In connection with the consummation of the Business Combination, all indebtedness under CRP's term loan and revolving credit facility was repaid in full. On October 11, 2016, CRP entered into a second amendment to the amended and restated credit agreement (the "second amendment"), which amends the amended and restated credit agreement, dated as of October 15, 2014, among CRP, each of the lenders from time to time party thereto and JPMorgan Chase Bank, N.A. as administrative agent (the "credit agreement"). CRP entered into the second amendment to, among other things, (i) permit the Business Combination, (ii) reflect the repayment in full of all term loans thereunder, (iii) increase the borrowing base from $140.0 million to $200.0 million, (iv) increase the interest rate to LIBOR plus 225 to 325 basis points, and (v) require CRP to have sufficient liquidity and satisfy a maximum leverage ratio in order to make dividends.

On December 28, 2016, in connection with the closing of the Silverback Acquisition, CRP entered into a third amendment to the amended and restated credit agreement (the "third amendment"), which further amends the credit agreement. CRP entered into this amendment to, among other things, increase the borrowing base thereunder from $200.0 million to $250.0 million.

The amount available to be borrowed under CRP's revolving credit facility is subject to a borrowing base that will be redetermined semiannually each April 1 and October 1 by the lenders in their sole discretion. CRP's credit agreement also allows for two optional borrowing base redeterminations on January 1 and July 1. The borrowing base depends on, among other things, the volumes of CRP's proved oil and natural gas reserves and estimated cash flows from these reserves and its commodity hedge positions. The borrowing base will automatically be decreased by an amount equal to 25% of the aggregate notional amount of issued permitted senior unsecured notes unless such decrease is waived by the lenders. Upon a redetermination of the borrowing base, if borrowings in excess of the revised borrowing capacity are outstanding, CRP could be required to immediately repay a portion of its debt outstanding under its credit agreement. The next regular redetermination date is scheduled for the spring of 2017.

Borrowings under its revolving credit facility may be base rate loans or LIBOR loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for LIBOR loans. LIBOR loans bear interest at LIBOR (adjusted for statutory reserve requirements) plus an applicable margin ranging from 225 to 325 basis points, depending on the percentage of the borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points, plus an applicable margin ranging from 125 to 225 basis points, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee on unused amounts of its revolving credit facility of 50 basis points. CRP may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

CRP's credit agreement contains restrictive covenants that limit its ability to, among other things: (1) incur additional indebtedness; (2) make investments and loans; (3) enter into mergers; (4) make or declare dividends; (5) enter into commodity hedges exceeding a specified percentage of its expected production; (6) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (7) incur liens; (8) sell assets; and (9) engage in transactions with affiliates.

CRP's credit agreement also requires it to maintain compliance with the following financial ratios: (1) a current ratio, which is the ratio of CRP's consolidated current assets (including unused commitments under CRP's revolving credit facility and excluding non-cash assets under FASB ASC Topic 815, *Derivatives and Hedging* ("ASC 815") and certain restricted cash) to consolidated current liabilities (excluding the current portion of long-term debt under its credit agreement and non-cash liabilities under ASC 815), of not less than 1.0 to 1.0; and (2) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP's credit agreement) to consolidated EBITDAX (as defined in CRP's credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0.

At December 31, 2016, there were no borrowings under the revolving credit facility. Outstanding letters of credit were $0.4 million, leaving $249.6 million in borrowing capacity under the revolving credit facility.

At December 31, 2016, the Company was in compliance with all required covenants.

Term Loan and Revolving Credit Facility (Predecessor)

On October 15, 2014, CRP entered into an amended and restated credit agreement (as amended, the "credit agreement") with JPMorgan Chase Bank, N.A., as administrative agent, and a syndicate of lenders, that includes both a term loan commitment of $65.0 million (the "term loan"), which was fully funded as of October 10, 2016, and a revolving credit facility (the "revolving credit facility") with commitments of $500.0 million (subject to the borrowing base), with a sublimit for letters of credit of $15.0 million. Prior to the Business Combination, the borrowing base was $140.0 million.

On October 10, 2016, CRP had $124.0 million outstanding under its revolving credit facility and $0.4 million of letters of credit outstanding, leaving $15.6 million in borrowing capacity under the revolving credit facility.

The credit agreement also has customary covenants with which CRP was in compliance on October 10, 2016, prior to the Business Combination.

The term loan, net of unamortized deferred financing costs on the accompanying consolidated balance sheets as of December 31, 2015, consisted of the following:

	Predecessor
(in thousands)	**December 31, 2015**
Term loan	$ 65,000
Unamortized deferred financing costs	(351)
Term loan, net of unamortized deferred financing costs	$ 64,649

Note 6—Income Taxes

As a result of the Business Combination, the Company became the sole managing member of CRP, and as a result, began consolidating the financial results of CRP. CRP is treated as a partnership for U.S. federal and most applicable state and local income tax purposes. As a partnership, CRP is not subject to U.S. federal and certain state and local income taxes. Any taxable income or loss generated by CRP is passed through to and included in the taxable income or loss of its members, including the Company, on a pro rata basis. The Company is subject to U.S. federal income taxes, in addition to state and local income taxes with respect to its allocable share of any taxable income or loss of CRP, as well as any stand-alone income or loss generated by the Company.

Income tax benefit (expense) are included in the consolidated statements of operations are detailed below:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	**January 1, 2016 through October 10, 2016**	**Year Ended December 31,**	
(in thousands)			**2015**	**2014**
Current taxes				
Federal	$ —	$ —	$ —	$ —
State	—	—	—	—
	—	—	—	—
Deferred taxes				
Federal	—	—	—	—
State	—	406	572	(1,524)
	—	406	572	(1,524)
Income tax benefit (expense)	$ —	$ 406	$ 572	$ (1,524)

A reconciliation of the statutory federal income tax expense to the income tax expense from continuing operations provided at December 31, 2016, is as follows:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
(in thousands)			2015	2014
Income tax (benefit) expense at the federal statutory rate	$ (3,145)	$ —	$ —	$ —
State income taxes - net of federal income tax benefits	—	406	572	(1,524)
Excess depletion	—	—	—	—
Noncontrolling interest in partnership	273	—	—	—
Nondeductible expenses	4	—	—	—
Change in valuation allowance	2,868	—	—	—
Income tax benefit (expense)	$ —	$ 406	$ 572	$ (1,524)

The tax effects of temporary differences that give rise to significant positions of the deferred income tax assets and liabilities are presented below:

	Successor	Predecessor
(in thousands)	December 31, 2016	December 31, 2015
Deferred tax assets:		
Net operating loss carryforwards	$ 2,590	$ —
Capitalized intangible drilling cost	10,314	—
Equity-based compensation	467	—
Other assets	291	—
Total deferred tax assets	13,662	—
Deferred tax liabilities:		
Investment in Centennial Resource Production, LLC	(8,514)	—
Other liabilities	—	(2,361)
Total deferred tax liabilities	(8,514)	(2,361)
Valuation allowance	(5,148)	—
Net deferred tax asset (liabilities)	$ —	$ (2,361)

For the period from October 11, 2016, through December 31, 2016 (Successor), equity was debited $5.6 million in connection with the issuance of shares to a noncontrolling interest owner. No tax benefit was recorded in equity as a $2.0 million valuation allowance fully offset the attendant tax benefit.

As of December 31, 2016, the Company had approximately $7.3 million of federal net operating loss carryovers that commence expiry in 2035.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. It is currently estimated that the Company's net deferred tax assets will not be utilized. Accordingly, a valuation allowance against the net deferred tax assets has been recorded at December 31, 2016.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon the examination by the Internal Revenue Service or other governmental agency. As of December 31, 2016, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. Interest and penalties related to uncertain tax positions are reported in income tax expense.

The Company is subject to the following material taxing jurisdictions: U.S., Colorado and Texas. As of December 31, 2016, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax years 2015 and 2016.

Note 7—Shareholders' and Owners' Equity

Shareholders' Equity (Successor)

At December 31, 2016, the Company had authorized 621,000,000 shares of capital stock, consisting of (a) 620,000,000 shares of common stock, including (i) 600,000,000 shares of Class A Common Stock, (ii) 20,000,000 shares of Class C Common Stock and (b) 1,000,000 shares of preferred stock, including one share of Series A Preferred Stock and 104,400 shares of Series B Preferred Stock.

On October 11, 2016, in connection with Business combination the Company issued and sold in private placements (i) 81,005,000 shares of Class A Common Stock to Riverstone Centennial Holdings, L.P. and (ii) the issuance and sale of 20,000,000 shares of Class A Common Stock to certain other accredited investors in a private placement, resulting in net cash proceeds of approximately $1.0 billion. The outstanding shares of Class B Common Stock, par value $0.0001 per share, converted into shares of Class A Common Stock on a one-for-one basis in connection with the Business Combination. Additionally, the Company issued 20,000,000 shares of Class C Common Stock to the Centennial Contributors and one share of Series A Preferred Stock to CRD in connection with the Business Combination. Holders of Class C Common Stock, generally have the right to cause CRP to redeem all or a portion of their CRP Common Units in exchange for shares of the Company's Class A Common Stock or, at CRP's option, an equivalent amount of cash. The Company may, however, at its option, effect a direct exchange of cash or Class A Common Stock for such CRP Common Units in lieu of such a redemption by CRP. Upon the future redemption or exchange of CRP Common Units held by a Centennial Contributor, a corresponding number of shares of Class C Common Stock will be canceled.

On December 28, 2016, in connection with the Silverback Acquisition, the Company issued and sold in private placements (i) 3,473,590 shares of Class A Common Stock and 104,400 shares of Series B Preferred Stock to Riverstone VI Centennial QB Holdings, L.P., Riverstone Non-ECI USRPI AIV, L.P. and REL US Centennial Holdings, LLC, which are affiliates of Riverstone Investment Group LLC and (ii) 33,012,380 shares of the Company's Class A Common Stock to certain other investors, resulting in net cash proceeds of approximately $889.6 million. The Company used the proceeds from the private placements to fund the cash consideration for the Silverback Acquisition and expect to use any remaining proceeds for general corporate purposes. The shares of Series B Preferred Stock are automatically convertible into shares of the Company's Class A Common Stock on a 250-to-one basis (subject to certain adjustments for stock splits, stock dividends, reorganization, recapitalizations and the like) at such time as the Company receives stockholder approval for the issuance of such shares of Class A Common Stock in compliance with NASDAQ listing rules.

Class A Common Stock

The Company had 201,091,646 shares of Class A Common Stock outstanding as of December 31, 2016, consisting of (i) 50,000,000 shares of Class A Common Stock issued as part of Units in connection with the IPO, (ii) 12,500,000 shares of Class A Common Stock issued upon conversion of the Company's Class B Common Stock, par value $0.0001 per share, in connection with the Business Combination (iii) 101,005,000 shares of Class A Common Stock issued in private placements in connection with the Business Combination, (iv) 844,079 shares of Class A Common Stock issued upon the redemption of CRP Common Units and cancellation of shares of Class C Common Stock, (v) 36,485,970 shares of Class A Common Stock issued in private placements in connection with the Silverback Acquisition and (vi) 256,597 restricted shares of Class A Common Stock issued to the Company's directors and executive officers. Additional shares of Class A Common Stock may be issued by the Company upon the exchange of CRP Common Units and cancellation of shares of Class C Common Stock pursuant to the A&R LLC Agreement (as defined below), the conversion of the Series B Preferred Stock and the exercise of the Company's outstanding Warrants.

Holders of the Company's Class A Common Stock are entitled to one vote for each share held on all matters to be voted on by the Company's stockholders. Holders of the Class A Common Stock and holders of the Class C Common Stock will vote together as a single class on all matters submitted to a vote of the Company's stockholders, except as required by law. Unless specified in the Charter (including any certificate of designation of preferred stock) or Bylaws, or as required by applicable provisions of the Delaware General Corporation Law or applicable stock exchange rules, the affirmative vote of a majority of the Company's shares of common stock that are voted is required to approve any such matter voted on by the Company's stockholders. There is no cumulative voting with respect to the election of directors, with the result that the holders of more than 50% of the shares voted for the election of directors can elect all of the directors (subject to the right of the holder of the

Company's Series A Preferred Stock to nominate and elect one director). Subject to the rights of the holders of any outstanding series of preferred stock, the Company's stockholders are entitled to receive ratable dividends when, as and if declared by the board of directors out of funds legally available therefor.

In the event of a liquidation, dissolution or winding up of the Company, the holders of the Class A Common Stock are entitled to share ratably in all assets remaining available for distribution to them after payment of liabilities and after provision is made for each class of stock, if any, having preference over the Class A Common Stock. The Company's stockholders have no preemptive or other subscription rights. There are no sinking fund provisions applicable to the Class A Common Stock.

Class C Common Stock

The Company had 19,155,921 shares of Class C Common Stock outstanding as of December 31, 2016, which represent the portion of the 20,000,000 shares of Class C Common Stock issued to the Centennial Contributors in connection with the Business Combination that had not been redeemed or exchanged as of such date.

Holders of Class C Common Stock, together with holders of Class A Common Stock voting as a single class, will have the right to vote on all matters properly submitted to a vote of the stockholders. In addition, the holders of Class C Common Stock, voting as a separate class, will be entitled to approve any amendment, alteration or repeal of any provision of the Company's Charter that would alter or change the powers, preferences or relative, participating, optional or other or special rights of the Class C Common Stock. Holders of Class C Common Stock will not be entitled to any dividends from the Company and will not be entitled to receive any of its assets in the event of any voluntary or involuntary liquidation, dissolution or winding up of its affairs.

Shares of Class C Common Stock may be issued only to the Centennial Contributors, their respective successors and assigns, as well as any permitted transferees of the Centennial Contributors. A holder of Class C Common Stock may transfer shares of Class C Common Stock to any transferee (other than the Company) only if such holder also simultaneously transfers an equal number of such holder's CRP Common Units to such transferee in compliance with the A&R LLC Agreement (as defined below). Holders of Class C Common Stock generally have the right to cause CRP to redeem all or a portion of their CRP Common Units in exchange for shares of the Company's Class A Common Stock or, at CRP's option, an equivalent amount of cash. The Company may, however, at its option, effect a direct exchange of cash or Class A Common Stock for such CRP Common Units in lieu of such a redemption by CRP. Upon the future redemption or exchange of CRP Common Units held by a Centennial Contributor, a corresponding number of shares of Class C Common Stock will be canceled.

Preferred Stock

As of December 31, 2016, the Company had outstanding one share of Series A Preferred Stock, issued to CRD in connection with the Business Combination, and 104,400 shares of Series B Preferred Stock, issued and sold to certain affiliates of Riverstone in connection with the Silverback Acquisition.

CRD, as the holder of the Series A Preferred Stock, will not be entitled to any dividends from the Company, but will be entitled to preferred distributions in liquidation in the amount of $0.0001 per share of Series A Preferred Stock and will have a limited voting right as described below. The Series A Preferred Stock will be redeemable by the Company (a) at such time as CRD and its affiliates cease to own, in the aggregate, at least 5,000,000 CRP Common Units and/or shares of Class A Common Stock (as adjusted for stock splits, stock dividends, reorganizations, recapitalizations and other similar transactions), (b) at any time at CRD's option or (c) upon a breach by CRD of the transfer restrictions relating to the Series A Preferred Stock. In addition, for so long as the Series A Preferred Stock remains outstanding, CRD will be entitled to nominate one director for election to the Company's board of directors in connection with any vote of the Company's stockholders for the election of directors, and the vote of CRD will be the only vote required to elect such nominee to the Company's board of directors.

Holders of Series B Preferred Stock generally will not have any voting rights, except as required by law. Notwithstanding the foregoing, the affirmative vote of holders of a majority of the Series B Preferred Stock then outstanding, voting as a separate class, is required to (a) approve any amendment, alteration or repeal of any provision of the Certificate of Designation relating to the Series B Preferred Stock or the Charter that adversely affects the rights, preferences, privileges or voting powers of the Series B Preferred Stock or (b) authorize the issuance of any senior securities or parity securities. With respect to any matter on which the holders of Series B Preferred Stock are entitled to vote, each share of Series B Preferred Stock will be entitled to one vote on such matter.

Beginning on December 28, 2019, the third anniversary of the closing date of the Silverback Acquisition, the Company will have the right, but not the obligation, to redeem all (but not less than all) of each holder's shares of Series B Preferred Stock for a redemption price per share, determined on an as-converted basis, equal to the average of the last reported sale price for a share of Class A Common Stock on NASDAQ for each of the last ten consecutive trading days prior to the redemption date or, if such shares are no longer traded, at the fair market value of the Class A Common Stock, as determined in good faith by the Company's board of directors. In the event of a voluntary or involuntary liquidation, dissolution or winding up of the Company, holders of the Series B Preferred Stock will first be entitled to receive the liquidation preference per share of $0.0001 before any distribution of assets is made to holders of any junior securities.

The shares of Series B Preferred Stock are automatically convertible into shares of the Company's Class A Common Stock on a 250-to-one basis (subject to certain adjustments) at such time as the Company receives stockholder approval for the issuance of such shares of Class A Common Stock in compliance with NASDAQ listing rules.

Warrants

As of December 31, 2016, the Company had 24,666,643 warrants outstanding, consisting of 16,666,643 public warrants originally sold as part of the Units in the IPO and 8,000,000 Private Placement Warrants sold to the Company's Sponsor in a private placement. Each whole warrant entitles the holder to purchase one whole share of Class A Common Stock for $11.50 per share. The warrants became exercisable on March 1, 2017 and will expire five years after the completion of the Business Combination or earlier upon redemption or liquidation.

On March 1, 2017, the Company delivered a notice of redemption of the Public Warrants, announcing its intention to redeem any unexercised and outstanding Public Warrants on March 31, 2017 for $0.01 per Public Warrant. As permitted under the warrant agreement that provides the terms of the Public Warrants, the notice of redemption requires all holders exercising their Public Warrants prior to March 31, 2017 to do so on a "cashless basis" and surrender their Public Warrants for a number of shares of Class A Common Stock equal to the product of the quotient equal to (i) the difference between $11.50 and $18.44 (the average last sale price of the Class A Common Stock for the ten trading days ending on February 24, 2017) divided by (ii) $18.44, or approximately 0.376, multiplied by the number of Public Warrants held by such holder, rounded down to the nearest whole share. Assuming all warrants are exercised by holders, Centennial will issue approximately 6.27 million shares of Class A Common Stock to the Public Warrant holders, resulting in a share count of approximately 253 million shares outstanding, which includes Class A Common Stock shares, the shares of Series B Preferred Stock held by Riverstone (assuming conversion to Class A Common Stock on a 250-to-one basis), and the shares of Class C Common Stock held by the Centennial Contributors. The Private Placement Warrants are non-redeemable so long as they are held by our Sponsor or its permitted transferees.

Noncontrolling Interest

As a result of the exchange of CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock (discussed in *Note 12—Transactions with Related Parties*) on October 11, 2016, the Company's ownership in CRP increased from 89.1% to 89.6% and the ownership of the other holders of CRP Common Units in CRP decreased from 10.9% to 10.4%. Because the increase in the Company's ownership interest in CRP did not result in a change of control, the transaction was accounted for as an equity transaction under ASC Topic 810, *Consolidations*, which requires that any differences between the amount by which the carrying value of the Company's basis in CRP and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest.

As a result of the December 28, 2016 private placements and the issuance of shares of Class A Common Stock and Series B Preferred Stock to the investors therein (discussed in *Note 12—Transactions with Related Parties*), the net proceeds of which were contributed by the Company to CRP, the Company's ownership of CRP increased from 89.6% to 92.2% and the other holders of CRP Common Units decreased from 10.4% to 7.8%.

The Company has consolidated the financial position and results of operations of CRP and reflected that portion retained by the other holders of CRP Common Units as a noncontrolling interest.

The following table summarizes the noncontrolling interest income (loss):

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Net loss attributable to noncontrolling interest	$ (904)	$ —	$ —	$ (2)

Owners' Equity (Predecessor)

At October 10, 2016 (prior to the Business Combination), members included Centennial HoldCo, Celero and Follow-On, owning an approximate 61.2%, 21.2% and 17.6% membership interest in Centennial OpCo, respectively. CRP has two classes of membership interests outstanding: Class A, which consist of membership interests held by CRD and Follow-On; and Class B, which consist of membership interests held by Celero. On October 10, 2016 CRP recorded a deemed contribution attributable to the consummation of the Business Combination, which resulted in a Fundamental Change with respect to the incentive units and

CRP recorded $165.4 million of compensation expense. Refer to *Note 7—Shareholders' and Owners' Equity*. Additionally, CRP recorded a deemed contribution of $14.0 million attributable to certain transaction costs related to the Business Combination paid by the Centennial Contributors. Refer to *Note 2—Business Combination*.

As of December 31, 2015, CRD had contributed $289.4 million and had a remaining capital commitment of $32.5 million, Follow-On had contributed $84.2 million and had a remaining capital commitment of $100.3 million, and Celero had contributed $125.4 million and has no remaining capital commitment.

In 2015 Follow-On contributed $84.2 million to Centennial OpCo in exchange for membership interests in Centennial CRP. In addition, CRD contributed approximately $27.2 million to CRP in exchange for additional membership interests in CRP.

Note 8—Equity Based Compensation

Equity based compensation (Successor)

The Company has recognized non-cash stock-based compensation cost as shown below. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

	Successor
(in thousands)	**October 11, 2016 through December 31, 2016**
Restricted stock awards	$ 405
Stock option awards	928
Total equity based compensation expense	$ 1,333

<u>Equity Incentive Plan</u>

On October 7, 2016, the stockholders of the Company approved the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (the “LTIP”). An aggregate of 16,500,000 shares of Class A common stock will be available for issuance under the LTIP. The LTIP provides for grant of stock options, including incentive stock options ("ISOs") and nonqualified stock options ("NSOs"), stock appreciation rights ("SARs"), restricted stock, dividend equivalents, restricted stock units ("RSUs") and other stock or cash based awards.

<u>Restricted Stock</u>

The following table provides information about restricted stock awards granted in 2016:

	Successor	
	Awards	**Weighted Average Grant-Date Fair Value**
Service-based stock awards:		
Outstanding as of October 11, 2016	—	$ —
Vested	—	$ —
Granted	256,597	$ 20.03
Canceled	—	$ —
Outstanding as of December 31, 2016	256,597	$ 20.03

Compensation cost for the service-based vesting restricted shares is based upon the grant-date market value of the award. Such costs are recognized ratably over the applicable vesting period. Unrecognized compensation cost related to unvested restricted shares at December 31, 2016 was $4.7 million. The Company expects to recognize that cost over a weighted average period of 2.6 years.

<u>Stock Options</u>

Options that have been granted under the LTIP expire ten years from the grant date and have service-based vesting schedules of three years. The exercise price for an option under the LTIP is the closing price of the Company’s common stock as reported by NASDAQ on the date of grant.

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. The Company estimates the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the re-levered asset volatility implied by a set of comparable companies. Expected term is based on the simplified method, and is estimated as the average of the weighted average vesting term and the time to expiration as of the grant date. The Company uses U.S. Treasury bond rates in effect at the grant date for its risk-free interest rates.

The following summarizes the options granted and related information, and the assumptions used to determine the fair value of those options.

	Successor
	October 11, 2016 through December 31, 2016
Options granted	2,760,500
Weighted average grant-date fair value	$ 5.93
Weighted average exercise price	$ 14.67
Total fair value (in thousands)	$ 16,375
Expected term	6
Expected stock volatility	40.0%
Dividend yield	—%
Risk-free interest rate	1.5%

Information about outstanding stock options is summarized in the table below:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of October 11, 2016	—	$ —	—	—
Exercised	—	$ —	—	—
Granted	2,760,500	$ 14.67	5.8	$ 13,934
Forfeited	(25,000)	$ 14.52	5.8	$ 130
Outstanding as of December 31, 2016	2,735,500	$ 14.67	5.8	$ 13,804
Exercisable as of December 31, 2016	—	$ —	—	$ —

The following summary reflects the status of non-vested stock options as of December 31, 2016 and changes since the Business Combination on October 11, 2016:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of October 11, 2016	—	$ —	$ —
Vested	—	$ —	$ —
Granted	2,760,500	$ 5.93	$ 14.67
Forfeited	(25,000)	$ 5.86	$ 14.52
Non-vested as of December 31, 2016	2,735,500	$ 5.93	$ 14.67

As of December 31, 2016, there was $15.3 million of unrecognized compensation cost related to non-vested stock options. The Company expects to recognize that cost on a pro rata basis over a weighted average period of 2.8 years.

Equity based compensation (Predecessor)

Incentive Units

Certain employees of Centennial Resource Management, LLC, a wholly owned subsidiary of CRD at the time of grant, received an award of CRD and NGP Follow-On incentive units, or profits interests. All of the incentive units are non-voting and subject to certain vesting and performance conditions. The terms of the incentive units are as follows: Tier I and Tier II incentive units vest ratably over five years, but are subject to forfeiture if payout is not achieved. In addition, all unvested Tier I and Tier II incentive units vest immediately upon Tier I and Tier II payout, respectively. Tier III, IV and V incentive units vest only upon the achievement of certain payout thresholds for each such tier and each tier of incentive units is subject to forfeiture if the applicable required payouts are not achieved. In addition, vested and unvested incentive units are forfeited if an incentive unit holder's employment is terminated for any reason or if the incentive unit holder voluntarily terminates their employment. Payouts for each Tier I through Tier V are based upon achievement of specified rates of return on CRD and NGP Follow-Ons invested capital.

The incentive units are issued to employees in return for services provided and cash payout is based, in part, on the value of Centennial equity; therefore, the incentive units are accounted for as liability awards under ASC 718, with compensation expense based on period-end fair value. The achievement of payout conditions is a performance condition that requires CRP to assess, at each reporting period, the probability that an event of payout will occur. Compensation cost is required to be recognized at such time that the payout terms are probable of being met. The consummation of the Business Combination resulted in a Fundamental Change with respect to the incentive units and CRP recorded $165.4 million of compensation expense. No incentive compensation expense was recorded at December 31, 2015 or 2014, because it was not probable that the performance criterion would be met.

Note 9—Derivative Instruments

The Company periodically uses derivative instruments to mitigate its exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. Depending on changes in oil and natural gas futures markets and the Company's view of underlying supply and demand trends, it may increase or decrease its hedging positions.

The following table summarizes the approximate volumes and average contract prices of swap contracts the Company had in place as of December 31, 2016:

	2017	2018
Crude Oil Swaps:		
Notional volume (Bbl)	675,250	36,500
Weighted average fixed price ($/Bbl)	$ 50.41	$ 55.95
Crude Oil Basis Swaps:		
Notional volume (Bbl)	127,750	—
Weighted average fixed price ($/Bbl)	$ (0.20)	$ —
Natural Gas Swaps:		
Notional volume (MMBtu)	1,460,000	—
Weighted average fixed price ($/MMBtu)	$ 2.94	$ —

In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. In addition, the Company has entered into basis swap contracts in order to hedge the difference between the NYMEX index price and a local index price. The oil basis derivative contracts are settled based on the difference between the arithmetic average of WTI MIDLAND ARGUS and WTI ARGUS during the relevant calculation period. When the actual differential exceeds the fixed price provided by the basis swap contract, the Company receives the difference from the counterparty; when the differential is less than the fixed price provided by the basis swap contract, the Company pays the difference to the counterparty.

The Company's commodity derivatives are measured at fair value and are included in the accompanying consolidated balance sheets as derivative assets and liabilities. The fair value of the commodity contracts was a net liability of $5.0 million and a net asset of $21.1 million as of December 31, 2016 and December 31, 2015, respectively.

The following tables below summarize the gross fair value of derivative assets and liabilities and the effect of netting on the consolidated balance sheets (in thousands):

	Successor			
	December 31, 2016			
	Balance Sheet Classification	Gross Amounts	Netting Adjustments	Net Amounts Presented on the Consolidated Balance Sheets
Assets				
Derivative instruments	Current assets	$ 739	$ (308)	$ 431
Derivative instruments	Noncurrent assets	—	—	—
Total assets		$ 739	$ (308)	$ 431
Liabilities				
Derivative instruments	Current liabilities	$ 5,669	$ (308)	$ 5,361
Derivative instruments	Noncurrent Liabilities	20	—	20
Total liabilities		$ 5,689	$ (308)	$ 5,381

	Predecessor			
	December 31, 2015			
	Balance Sheet Classification	Gross Amounts	Netting Adjustments	Net Amounts Presented on the Consolidated Balance Sheets
Assets				
Derivative instruments	Current assets	$ 19,469	$ (426)	19,043
Derivative instruments	Noncurrent assets	2,071	(1)	2,070
Total assets		$ 21,540	$ (427)	$ 21,113

The Company's oil and natural gas derivative instruments have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in the Company's consolidated and combined statements of operations. The derivative instruments are recorded at fair value on the consolidated balance sheets and any gains and losses are recognized in current period earnings.

The following table presents gains and losses for derivative instruments not designated as hedges for accounting purposes for the periods presented (in thousands):

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
			2015	2014
(Loss) gain on derivative instruments	$ (1,548)	$ (6,838)	$ 20,756	$ 41,943

The Company is exposed to financial risks associated with its derivative contracts from non-performance by its counterparties. The Company mitigates its exposure to any single counterparty by contracting with a number of financial institutions, each of which have a high credit rating and is a member of its bank credit facility. The Company's member banks do not require it to post collateral for its hedge liability positions. Because some of the member banks have discontinued hedging activities, in the future the Company may hedge with counterparties outside its bank group to obtain competitive terms and to spread counterparty risk.

Note 10—Fair Value Measurements

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

The following table is a listing of the Company's assets and liabilities that are measured at fair value and where they were classified within the fair value hierarchy as of December 31, 2016 and December 31, 2015 (in thousands):

	Successor		
	December 31, 2016		
	Level 1	Level 2	Level 3
Commodity derivative liability, net	$ —	$ 4,950	$ —

	Predecessor		
	December 31, 2015		
	Level 1	Level 2	Level 3
Commodity derivative asset, net	$ —	$ 21,113	$ —

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy. There were no transfers between Level 1, Level 2 or Level 3 during any period presented.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and natural gas commodity derivatives. The Company uses industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied market volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

Nonrecurring Fair Value Measurements

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation. Refer to *Note 2—Business Combination* and *Note 3—Property Acquisitions and Dispositions* for additional information on the fair value of assets acquired during 2016.

Other Financial Instruments

The carrying amounts of the Company's cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying values of the amounts outstanding under the credit agreement approximate fair value because the variable interest rates are reflective of current market conditions.

Note 11—Asset Retirement Obligations

The following table summarizes the changes in the Company's asset retirement obligations for the periods presented:

	Successor	Predecessor	
(in thousands)	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31, 2015
Asset retirement obligations, beginning of period	$ 4,989	$ 2,288	$ 1,824
Liabilities incurred	187	174	133
Liabilities acquired	2,002	66	178
Liabilities settled	(1)	(42)	—
Accretion expense	49	134	139
Revision of estimated liabilities	—	32	14
Asset retirement obligations, end of period	$ 7,226	$ 2,652	$ 2,288

AROs reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance.

Note 12—Transactions with Related Parties

Founder Shares

On November 6, 2015, the Company's Sponsor purchased 11,500,000 shares of Class B Common Stock, the founder shares, from the Company, for an aggregate purchase price of $25,000, or approximately $0.002 per share. In February 2016, the Company's Sponsor transferred 40,000 founder shares to each of the Company's then independent directors (together with the Company's Sponsor, the "initial stockholders") at their original purchase price. On February 24, 2016, the Company effected a stock dividend of approximately 0.125 shares for each outstanding share of Class B Common Stock, resulting in the initial stockholders holding an aggregate of 12,937,000 founder shares. On April 8, 2016, following the expiration of the underwriters' remaining over-allotment option in connection with the Company's IPO, the Company's Sponsor forfeited 437,500 founder shares, so that the remaining 12,500,000 founder shares held by the initial stockholders would represent 20% of the Company's then issued and outstanding shares of common stock. On October 11, 2016, all of the outstanding founder shares were automatically converted into shares of Class A Common Stock on a one-for-one basis in connection with the closing of the Business Combination.

The initial stockholders have agreed, subject to limited exceptions, not to transfer, assign or sell any of their shares of Class A Common Stock received upon conversion of their founder shares until the earlier to occur of: (A) one year after the closing of the Business Combination or (B) subsequent to the Business Combination, (x) if the last sale price of the Class A Common Stock equals or exceeds $12.00 per share (as adjusted for stock splits, stock dividends, reorganizations, recapitalizations and the like) for any 20 trading days within any 30 trading day period commencing at least 150 days after the closing of the Business Combination, or (y) the date on which the Company completes a liquidation, merger, stock exchange or other similar transaction that results in all of its stockholders having the right to exchange their shares of common stock for cash, securities or other property.

Administrative Support Agreement

On February 23, 2016, the Company entered into an administrative support agreement pursuant to which it agreed to pay an affiliate of its Sponsor a total of $10,000 per month for office space, utilities and secretarial and administrative support. The Company paid the affiliate of the Sponsor $70,000 for such services for the nine months ended September 30, 2016. Following the closing of the Business Combination, the Company no longer pays these monthly fees.

Private Placement Warrants

On February 29, 2016, the Company's Sponsor purchased 8,000,000 Private Placement Warrants from the Company at a price of $1.50 per whole warrant ($12.0 million in the aggregate) in a private placement that occurred simultaneously with the closing of the Company's IPO. Each whole Private Placement Warrant is exercisable for one whole share of Class A Common Stock at a price of $11.50 per share. A portion of the purchase price of the Private Placement Warrants was placed in the

Company's trust account along with the proceeds from its IPO. The Private Placement Warrants are non-redeemable and exercisable on a cashless basis so long as they are held by the Company's Sponsor or its permitted transferees.

Related Party Loans

On November 6, 2015, the Company's Sponsor agreed to loan it an aggregate of up to $300,000 to cover expenses related to its IPO pursuant to a promissory note (the "2015 Note"). The 2015 Note was non-interest bearing and payable on the earlier of March 31, 2016 or the completion of the Company's IPO. On November 10, 2015, the Company borrowed $150,000 under the 2015 Note, and it borrowed the remaining $150,000 under the 2015 Note in February 2016. On February 29, 2016, the full $300,000 balance of the 2015 Note was repaid to the Company's Sponsor.

On August 2, 2016, the Company issued an unsecured, non-interest bearing promissory note to its Sponsor (the "2016 Note"). The Company borrowed $300,000 under the 2016 Note, and repaid the full $300,000 balance upon the closing of the Business Combination on October 11, 2016.

Exchange Right

On October 11, 2016, following the closing of the Business Combination, the Company issued 844,079 shares of its Class A Common Stock, par value $0.0001 per share, to an accredited investor at the direction of members of CRP affiliated with such investor (the "CRP Members"), in exchange for 844,079 common membership interests in CRP (the "CRP Common Units") held by certain Centennial Contributors. The exchange was effected in accordance with the Fifth Amended and Restated Limited Liability Company Agreement of CRP, which permits Centennial Contributors of CRP Common Units to exchange their CRP Common Units on a one-for-one basis for shares of Class A Common Stock. Upon the exchange of the CRP Common Units described above, the Company canceled 844,079 shares of its Class C Common Stock, par value $0.0001 per share, held by the Centennial Contributors.

Amended and Restated Limited Liability Company Agreement of CRP

In connection with the closing of the Business Combination, on October 11, 2016, the Company and the Centennial Contributors entered into CRP's fifth amended and restated limited liability company agreement (the "A&R LLC Agreement"). The operations of CRP, and the rights and obligations of the holders of CRP Common Units, are set forth in the A&R LLC Agreement.

On December 28, 2016 and March 20, 2017, in connection with the Silverback Acquisition, the A&R LLC Agreement was amended by Amendment No. 1 to the A&R LLC Agreement and Amendment No. 2 to the A&R LLC Agreement, respectively (the "CRP Amendments"). Pursuant to the CRP Amendments, the Series B Preferred Units were created, with 104,400 of such Series B Preferred Units issued to the Company, in connection with the contribution of proceeds from the Silverback Acquisition Private Placements. Pursuant to the CRP Amendments, the Series B Preferred Units have limited voting rights and are entitled to participate with the CRP Common Units in any distributions declared in accordance with the A&R LLC Agreement. The Series B Preferred Units will automatically convert to CRP Common Units upon the conversion of the Company's Series B Preferred Stock.

Amended and Restated Registration Rights Agreement

In connection with the closing of the Business Combination, on October 11, 2016, the Company entered into an amended and restated registration rights agreement (the "Registration Rights Agreement") with its Sponsor, certain of its former and current directors, Riverstone Centennial Holdings, L.P. ("Riverstone Centennial") and the Centennial Contributors, pursuant to which such parties are entitled to certain registration rights relating to (i) shares of the Company's Class A Common Stock issued to our Sponsor and such former and current directors upon the conversion of their founder shares at the closing of the Business Combination, (ii) the Private Placement Warrants and warrants that may be issued upon conversion of working capital loans (and any shares of Class A Common Stock issuable upon the exercise of such warrants), (iii) the shares of Class A Common Stock that have been or may be issued from time to time to certain members of CRP who own CRP Common Units upon the redemption or exchange by such members of CRP Common Units for shares of Class A Common Stock (the "Centennial Holder Shares") and (iv) the shares of Class A Common Stock issued to Riverstone Centennial in the Business Combination Private Placement (collectively, the "Registrable Securities").

The holders of a majority of the Registrable Securities (other than the securities identified in clauses (iii) and (iv) of the preceding paragraph) are entitled to make up to three demands, excluding short form demands, that the Company register the resale of such securities, while holders of a majority of the Registrable Securities owned by Riverstone Centennial and its permitted transferees are entitled to five demands, excluding short form demands, that the Company register the resale of such securities. Additionally, the holders of a majority of the Centennial Holder Shares are entitled to demand one underwritten offering if the offering is reasonably expected to result in gross proceeds of more than $50 million. In connection with this

Amended and Restated Registration Rights Agreement, the Company filed a Registration Statement on Form S-1 that was declared effective on November 21, 2016.

The holders also have certain "piggy-back" registration rights with respect to registration statements and rights to require the Company to register for resale such securities pursuant to Rule 415 under the Securities Act. However, the Registration Rights Agreement provides that the Company will not permit any registration statement filed under the Securities Act with respect to the founder shares and the Private Placement Warrants and the shares of Class A Common Stock underlying such Private Placement Warrants to become effective until termination of the applicable lock-up period, which occurs (i) in the case of the founder shares, on the earlier of (A) October 11, 2017, (B) if the last sale price of the Company's Class A Common Stock equals or exceeds $12.00 per share (as adjusted for stock splits, stock dividends, reorganizations, recapitalizations and other similar transactions) for any 20 trading days within any 30-trading day period commencing at least 150 days after the Business Combination, or (C) the date on which the Company completes a liquidation, merger, capital stock exchange, reorganization or other similar transaction that results in all of its stockholders having the right to exchange their shares of common stock for cash, securities or other property and (ii) in the case of the Private Placement Warrants and the shares of Class A Common Stock underlying such Private Placement Warrants, November 11, 2016. The Company will bear the expenses incurred in connection with the filing of any such registration statements.

Subscription Agreements

In connection with the Business Combination, on July 21, 2016, the Company entered into subscription agreements with certain investors pursuant to which such investors purchased, in the aggregate, 20,000,000 shares of Class A Common Stock at the closing of the Business Combination for an aggregate purchase price of $200.0 million. On the same date, the Company entered into a separate subscription agreement with Riverstone Centennial, pursuant to which Riverstone Centennial purchased 81,005,000 shares of Class A Common Stock at the closing of the Business Combination for an aggregate purchase price of approximately $810.0 million.

In connection with the Silverback Acquisition, on November 27, 2016 (as amended on December 22, 2016), the Company entered into a subscription agreement with the Riverstone Purchasers, pursuant to which the Riverstone Purchasers agreed to purchase an aggregate of 3,473,590 shares of Class A Common Stock and 104,400 shares of Series B Preferred Stock at the closing for an aggregate purchase price of approximately $430.0 million. In addition, on December 2, 2016, the Company entered into subscription agreements with the other selling stockholders, pursuant to which such selling stockholders agreed to purchase an aggregate of 33,012,380 shares of Class A Common Stock at the closing for an aggregate purchase price of approximately $480.0 million. The Company refers to the subscription agreements entered into by the selling stockholders, including the Riverstone Purchasers, as the "Subscription Agreements."

The shares of Class A Common Stock and Series B Preferred Stock issued pursuant to the Subscription Agreements were not registered under the Securities Act in reliance upon the exemption provided in Section 4(a)(2) of the Securities Act. The Subscription Agreements provide that the Company must register the resale of the shares of Class A Common Stock issued thereunder pursuant to a registration statement that must be filed within 75 calendar days after consummation of the Silverback Acquisition. The Subscription Agreements provide further that the Company must use its commercially reasonable efforts to have the registration statement declared effective as soon as practicable after the filing thereof, but no later than the earlier of (i) the 90th calendar day following the filing thereof and (ii) the 10th business day after the date the Company is notified (orally or in writing, whichever is earlier) by the SEC that such registration statement will not be "reviewed" or will not be subject to further review.

Customer and Supplier Relationships

NGP Affiliated Companies

In May 2016, the Company acquired acreage in close proximity to its operating area in Reeves County, Texas and wellbore only rights in an uncompleted horizontal wellbore for approximately $9.8 million from Caird DB, LLC, an affiliate of NGP.

From time to time, the Company obtains services related to its drilling and completion activities from affiliates of NGP. In particular, the Company has paid the following amounts to the following affiliates of NGP for such services: (i) approximately $0.5 million during the year ended December 31, 2016 to Cretic Energy Services, LLC ("Cretic"); and (ii) approximately $3.3 million during the year ended December 31, 2016 to RockPile Energy Services, LLC. On September 8, 2016, Rockpile Energy Services, LLC, was purchased from NGP by an unrelated third party. At December 31, 2016, included in *Accounts payable and accrued expenses* was $0.2 million due to Cretic.

The Company is party to a 15-year gas gathering agreement with PennTex Permian, LLC ("PennTex"), which terminates on April 1, 2029 and is subject to one-year extensions at either party's election. Under the agreement, PennTex gathers and processes the Company's gas. PennTex purchases the extracted natural gas liquids from the Company, net of gathering fees and an agreed percentage of the actual proceeds from the sale of the residue natural gas and natural gas liquids. Net payments received from PennTex for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor) and the years ended December 31, 2015 and 2014 were $0.2 million, $1.0 million, $1.2 million and $2.2 million, respectively. In the third quarter of 2016, PennTex sold its assets related to this agreement to an unrelated third party.

In October 2014, the gas gathering agreement with PennTex was amended to construct an expansion of the gathering system and a receipt point. Please refer to *Note 13—Commitments and Contingencies*.

<u>*Riverstone Affiliated Companies*</u>

From time to time, the Successor obtains services related to its drilling and completion activities from affiliates of Riverstone. In particular, the Successor has paid the following amounts to the following affiliates of Riverstone for such services: (i) approximately $8.2 million during the year ended December 31, 2016 to Liberty Oilfield Services, LLC ("Liberty"); and (ii) approximately $1.4 million during the year ended December 31, 2016 to Permian Tank and Manufacturing, Inc. ("Permian"). At December 31, 2016, included in *Accounts payable and accrued expenses* was $3.1 million and $0.4 million due to Liberty and Permian, respectively.

<u>*Other Affiliated Companies*</u>

Mark G. Papa, our President, Chief Executive Officer and Chairman of the Board, serves as a director and Chairman of the Board of Oil States International, Inc., an energy services company publicly traded on the New York Stock Exchange ("Oil States"). From time to time, the Successor obtains services related to drilling and completion activities from Oil States. In particular, during the fiscal year ended December 31, 2016, the Successor paid approximately $1.2 million to Oil States. At December 31, 2016, included in *Accounts payable and accrued expenses* was $0.2 million due to Oil States.

Note 13—Commitments and Contingencies

Operating Leases and Other Commitments

The following is a schedule of the Company's future minimum lease payments with commitments that have initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2016**:**

Years ending December 31,	Amount (in thousands)
2017	$ 8,147
2018	814
2019	573
2020	134
2021	79
Thereafter	7,226
Total	$ 16,973

Financing Obligation

In October 2014, the Company's gas gathering agreement with PennTex was amended to construct an expansion of the gathering system and a receipt point. The Company reimbursed PennTex for the total cost of the expansion project. The Company paid a minimum fee of $7,000 per day until PennTex recouped the capital outlay for the expansion project. At December 31, 2016, the financing obligation was paid in full. At December 31, 2015, a short-term liability of $2.1 million was in included in *Other current liabilities* on the consolidated balance sheets. For the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor) and for the year ended December 31, 2015, the Company made payments, including interest, of $0.1 million, $2.1 million and $1.7 million, respectively.

Transportation and Gathering Agreement

In December 2015, the Company entered into a transportation and gathering services agreement by which a transporter agreed to construct a crude oil gathering and transportation system capable of transporting crude oil from certain Company wells in Reeves and Ward Counties, Texas to destination points in Crane and Midland, Texas (the "Transportation System"), and the Company agreed to dedicate and ship on the Transportation System all crude oil owned or controlled by the Company from oil and gas leases covering approximately 28,000 gross acres located within a designated area of mutual interest in Reeves and Ward Counties. The agreement has a primary term of 12 years from October 1, 2016, the date the Transportation System was first put into service, and may be extended at the Company's option for two successive two-year terms and, thereafter, is automatically extended for successive one-year terms unless terminated by the Company or the transporter upon 60 days' prior notice.

Purchase Agreement

In July 2016, the Company entered into a crude oil purchase agreement by which the Company agreed to sell all of its crude oil production that is produced at receipt points identified in the agreement commencing on the October 1, 2016 in-service date of the Transportation System. The purchaser is obligated to purchase the crude oil at the receipt points identified in the agreement and transport it on the Transportation System. The agreement has an initial term of nine months from October 1, 2016, the date the Transportation System entered commercial service, and evergreen 30-day renewal terms unless terminated by the Company or the purchaser on 30 days' prior notice. The price received by the Company for the crude oil it sells under the agreement is based generally on NYMEX pricing subject to marketing and other adjustments, and varies depending on whether the oil is transported to Crane or Midland, Texas and on whether the oil is transported before or after the Transportation System is connected to a pipeline in Crane, Texas or a terminal in Midland, Texas.

Drilling Rig Contracts

As of December 31, 2016, the Company has four drilling rigs under contract. All of these contracts expire in 2017.

In light of the low commodity price environment, the Company curtailed its drilling activity during 2015. For the year-ended December 31, 2015, the Company incurred drilling rig termination fees of $2.4 million, which are recorded in the *Contract termination and rig stacking* line item in the accompanying consolidated and combined statements of operations.

Office Leases

The Company leases office space in Denver, Colorado, Midland, Texas, Sugar Land, Texas, and Pecos, Texas. The Company recognized rent expense of $0.1 million, $0.4 million, $0.4 million and $0.5 million for the periods from October 11, 2016, through December 31, 2016, January 1, 2016, through October 10, 2016, and for the years ended December 31, 2015 and December 31, 2014, respectively.

Contingencies

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows. Management is unaware of any pending litigation brought against the Company requiring the reserve of a contingent liability as of the date of these consolidated financial statements.

Supplemental Information About Oil & Natural Gas Producing Activities (Unaudited)

Costs Incurred For Oil and Natural Gas Producing Activities

The following table sets forth the capitalized costs incurred in the Company's oil and gas production, exploration, and development activities:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
(in thousands)			**2015**	**2014**
Acquisition costs:				
Proved properties	$ 561,251	$ 16,386	$ 14,268	$ 5,758
Unproved properties	1,905,660	39,399	28,955	16,409
Development costs	44,602	53,512	87,452	324,802
Exploration costs	844	—	84	—
Total	$ 2,512,357	$ 109,297	$ 130,759	$ 346,969

Results of Oil and Natural Gas Producing Activities

The results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs) are presented below:

(in thousands)	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues:				
Oil, natural gas and NGL sales	$ 29,717	$ 69,116	$ 90,460	$ 131,825
Costs:				
Lease operating expenses	3,541	11,036	21,173	17,690
Severance and ad valorem taxes	1,636	3,696	5,021	6,875
Transportation, processing, gathering and other operating expenses	2,187	4,583	5,732	4,772
Depletion, amortization and accretion of asset retirement obligations	14,486	62,228	89,350	68,981
Abandonment expense and impairment of unproved properties	—	2,545	7,619	20,025
Exploration	844	—	84	—
Contract termination and rig stacking	—	—	2,387	—
Income tax expense (benefit)	—	(406)	(572)	1,524
Results of operations	$ 7,023	$ (14,566)	$ (40,334)	$ 11,958

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with GAAP requirements for disclosures about oil and natural gas producing activities and Securities and Exchange Commission (“SEC”) rules for oil and natural gas reporting reserves estimation and disclosure.

Estimates of the Company’s proved oil and natural gas reserves at December 31, 2016, 2015 and 2014 were prepared by Netherland, Sewell & Associates, Inc. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The following table summarizes the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor) and for the years ended December 31, 2015 and 2014. The following prices, as adjusted for transportation, quality, and basis differentials, were used in the calculation of the standardized measure of discounted future net cash flows (“standardized measure”):

	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Oil (per Bbl)	$ 38.49	$ 36.98	$ 41.85	$ 84.94
Gas (per Mcf)	0.98	1.24	1.71	4.70
NGLs (per Bbl)	14.59	13.28	13.94	22.70

The table below presents a summary of changes in the Company’s estimated proved reserves:

	Successor			Predecessor		
	October 11, 2016, through December 31, 2016			January 1, 2016, through October 10, 2016		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)
Total proved reserves:						
Beginning of period	30,091	36,801	4,506	23,199	32,442	3,851
Extensions and discoveries	7,063	12,219	1,225	5,851	6,410	773
Revisions of previous estimates	184	16,445	983	1,025	(1,521)	(110)
Purchases of reserves in place	9,651	83,992	5,152	1,600	2,130	245
Divestitures of reserves in place	—	—	—	—	—	—
Production	(523)	(1,113)	(96)	(1,584)	(2,660)	(253)
End of period	46,466	148,344	11,770	30,091	36,801	4,506
Proved developed reserves:						
Beginning of period	11,346	14,973	1,927	9,347	12,711	1,603
End of period	14,551	42,190	3,618	11,346	14,973	1,927
Proved undeveloped reserves:						
Beginning of period	18,745	21,828	2,579	13,852	19,731	2,248
End of period	31,914	106,154	8,152	18,745	21,828	2,579

	Predecessor					
	Year Ended December 31, 2015			Year Ended December 31, 2014		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)
Total proved reserves:						
Beginning of period	19,850	27,414	1,551	18,510	6,968	525
Extensions and discoveries	9,444	11,927	1,432	16,122	22,575	1,127
Revisions of previous estimates	(5,109)	(5,204)	995	56	178	180
Purchases of reserves in place	844	1,363	204	162	192	23
Divestitures of reserves in place	—	—	—	(13,572)	(387)	(69)
Production	(1,830)	(3,058)	(331)	(1,428)	(2,112)	(235)
End of period	23,199	32,442	3,851	19,850	27,414	1,551
Proved developed reserves:						
Beginning of period	8,026	11,959	766	6,021	4,837	382
End of period	9,347	12,711	1,603	8,026	11,959	766
Proved undeveloped reserves:						
Beginning of period	11,823	15,455	785	12,489	2,131	143
End of period	13,852	19,731	2,248	11,823	15,455	785

Proved reserves at December 31, 2016 increased 104% to 82,959 MBoe, compared to 40,730 MBoe at October 10, 2016.

During the period from October 11, 2016, through December 31, 2016 (Successor), the Company acquired 28,801 MBoe of proved reserves. Refer to *Note 3—Property Acquisitions and Dispositions*. Additionally, the Company added 10,324 MBoe of proved reserves through extensions, primarily due to its drilling activity, as well as, 3,908 MBoe of revisions due to improved results in completion techniques and adjustments of natural gas and NGL treatment through the gas plants slightly offset by 805 MBoe of production.

Proved reserves at October 10, 2016 increased 25% to 40,730 MBoe, compared to 32,457 MBoe at December 31, 2015.

During the period from January 1, 2016, through October 10, 2016 (Predecessor), the Company acquired 2,200 MBoe of proved reserves. Refer to *Note 3—Property Acquisitions and Dispositions*. Additionally, the Company added 7,692 MBoe of proved reserves through extensions, primarily due to its drilling activity, as well as 660 MBoe due to positive performance revisions, slightly offset by 2,280 MBoe of production.

Proved reserves at December 31, 2015 increased 25% to 32,457 MBoe, compared to 25,970 MBoe at December 31, 2014.

During 2015, the Company added 12,864 MBoe of proved reserves through extensions, primarily due to its drilling activity.

During 2015, the Company had net negative revisions of 4,981 MBoe. The significant decrease in commodity prices seen in 2015 resulted in negative revisions related to the conversion of approximately 6,794 MBoe from PUDs to unproved reserves, partially offset by a positive revision in performance.

During 2015, the Company acquired 1,275 MBoe of proved reserves. Refer to *Note 3—Property Acquisitions and Dispositions*.

During 2014, the Company added 21,012 MBoe of proved reserves through extensions and discoveries, primarily due to its continued development drilling program and 265 MBoe of proved reserves, due to better than expected performance of its proved developed reserves.

During 2014, the Company divested of 13,706 MBoe of proved reserves. Refer to *Note 3—Property Acquisitions and Dispositions*.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties and consideration of expected future economic and operating conditions. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. The estimated future net cash flows are then discounted at a rate of 10%.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of its' Predecessor's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations and no value may be assigned to probable or possible reserves.

The following table presents the Company's standardized measure of discounted future net cash flows:

	Successor	Predecessor		
	October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016	Year Ended December 31,	
(in thousands)			**2015**	**2014**
Future cash inflows	$ 2,105,585	$ 1,217,641	$ 1,079,962	$ 1,850,205
Future development costs	(482,162)	(297,559)	(277,837)	(440,366)
Future production costs	(640,306)	(413,410)	(450,058)	(457,236)
Future income tax expenses	(136,587)	(5,614)	(6,643)	(10,834)
Future net cash flows	846,530	501,058	345,424	941,769
10% discount to reflect timing of cash flows	(471,438)	(291,345)	(210,355)	(575,886)
Standardized measure of discounted future net cash flows	$ 375,092	$ 209,713	$ 135,069	$ 365,883

The following summarizes the principal sources of change in the standardized measure of discounted future net cash flows:

(in thousands)	Successor October 11, 2016 through December 31, 2016	Predecessor January 1, 2016 through October 10, 2016
Standardized measure of discounted future net cash flows, beginning of period	$ 209,713	$ 135,069
Sales of oil, natural gas and NGLs, net of production costs	(22,354)	(49,801)
Purchase of minerals in place	127,842	10,145
Divestiture of minerals in place	—	—
Extensions and discoveries, net of future development costs	55,825	46,438
Change in estimated development costs	10,891	11,743
Net change in prices and production costs	(978)	6,661
Change in estimated future development costs	571	28,998
Revisions of previous quantity estimates	20,190	3,673
Accretion of discount	4,753	11,319
Net change in income taxes	(47,990)	(1,568)
Net change in timing of production and other	16,629	7,036
Standardized measure of discounted future net cash flows, end of period	$ 375,092	$ 209,713

(in thousands)	Predecessor Year Ended December 31, 2015	2014
Standardized measure of discounted future net cash flows, beginning of period	$ 365,883	$ 371,307
Sales of oil, natural gas and NGLs, net of production costs	(58,534)	(102,488)
Purchase of minerals in place	14,416	5,650
Divestiture of minerals in place	—	(242,344)
Extensions and discoveries, net of future development costs	57,894	312,532
Change in estimated development costs	16,100	10,386
Net change in prices and production costs	(494,734)	(3,027)
Change in estimated future development costs	247,642	2,935
Revisions of previous quantity estimates	(51,342)	924
Accretion of discount	37,517	13,561
Net change in income taxes	1,601	(2,762)
Net change in timing of production and other	(1,374)	(791)
Standardized measure of discounted future net cash flows, end of period	$ 135,069	$ 365,883

Selected Quarterly Financial Data (Unaudited)

(in thousands)	Predecessor				Successor
	Periods Ended				Period Ended
	March 31	June 30	September 30	October 1, 2016 through October 10, 2016	October 11, 2016 through December 31, 2016
2016					
Revenues	$ 15,121	$ 23,347	$ 27,321	$ 3,327	$ 29,717
Operating expenses	29,855	30,251	32,228	183,465	36,800
Gain (loss) on sale of oil and natural gas properties	(4)	—	15	—	24
Operating loss	(14,738)	(6,904)	(4,892)	(180,138)	(7,059)
Other income (expense)	277	(9,635)	(242)	(2,858)	(1,926)
Income tax expense (benefit)	—	406	—	—	—
Net loss	(14,461)	(16,133)	(5,134)	(182,996)	(8,081)
Loss per share:					
Basic					$ (0.05)
Diluted					$ (0.05)

(in thousands)	Predecessor			
	Quarters Ended			
	March 31	June 30	September 30	December 31
2015				
Revenues	$ 24,416	$ 22,431	$ 21,893	$ 21,720
Operating expenses	36,656	37,184	30,442	42,024
Gain (loss) on sale of oil and natural gas properties	2,675	4	9	(249)
Operating loss	(9,565)	(14,749)	(8,540)	(20,553)
Other income (expense)	3,628	(7,922)	11,866	6,938
Income tax expense	—	—	—	572
Net (loss) income	(5,937)	(22,671)	3,326	(13,043)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2016. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2016 at the reasonable assurance level.

Management's Annual Report on Internal Control Over Financial Reporting

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Changes in Internal Control over Financial Reporting

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

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors and Executive Officers

Set forth below are the names, ages and positions of each of each of our directors and executive officers:

Name	Age	Position	Class(1)
Mark G. Papa	70	President, Chief Executive Officer and Chairman of the Board	III
George S. Glyphis	47	Chief Financial Officer	0
Sean R. Smith	44	Chief Operating Officer	0
Maire A. Baldwin	51	Director	I
Robert M. Tichio	39	Director	I
Karl E. Bandtel	50	Director	II
Jeffrey H. Tepper	51	Director	II
David M. Leuschen	65	Director	III
Pierre F. Lapeyre, Jr.	54	Director	III
Tony R. Weber(2)	54	Director	—

(1) The term of office of the Class I directors expires at the annual meeting of stockholders in 2017, the term of office of the Class II directors expires at the annual meeting of stockholders in 2018, and the term of office of the Class III directors expires at the annual meeting of stockholders in 2019.

(2) Tony Weber has been nominated and elected to the board of directors by CRD as the holder of our Series A Preferred Stock. The term of office of Mr. Weber expires at the annual meeting of stockholders in 2017.

Mark G. Papa has been our Chief Executive Officer and a director since November 2015. Since the closing of the Business Combination, Mr. Papa also serves as our President. Mr. Papa is a Houston-based advisor to Riverstone. We currently anticipate that Mr. Papa will spend approximately 60% of his working time providing services to us as our President and Chief Executive Officer and approximately 40% of his working time providing services to Riverstone on matters unrelated to the Company. Prior to joining Riverstone in February 2015, Mr. Papa was Chairman and CEO of EOG Resources, Inc. (NYSE: EOG), an independent U.S. oil and gas company, from August 1999 to December 2013. Mr. Papa served as a member of EOG Resources' board of directors from August 1999 until December 2014. Mr. Papa worked at EOG Resources for 32 years in various management positions. Mr. Papa was retired from December 2013 through February 2015. Prior to joining EOG Resources, Mr. Papa worked at Conoco Inc. for 13 years in various engineering and management positions. Mr. Papa has also served on the board of Oil States Industries (NYSE: OIS), an international oil field services company, since February 2001 and Casa de Esperanza, a non-profit organization serving immigrants, since November 2006. In February 2010 and 2013, the Harvard Business Review cited Mr. Papa as one of the 100 Best Performing CEOs in the World; both times Mr. Papa was the highest ranked Global Energy CEO. Additionally, Institutional Investor magazine repeatedly ranked him as the Top Independent E&P CEO. He received his B.S. in petroleum engineering from the University of Pittsburgh and an MBA from the University of Houston. We believe Mr. Papa's significant experience in the energy industry make him well qualified to serve as a member of the board of directors.

George S. Glyphis has been our Chief Financial Officer since the closing of the Business Combination. He has served as Vice President and Chief Financial Officer of Centennial Resource Management, LLC (the "Management Company") since July 2014. Prior to joining the Management Company, Mr. Glyphis served as a Managing Director in the Oil & Gas Investment Banking practice at J.P. Morgan where his client base comprised primarily upstream and integrated oil and gas companies. In his 21 years at J.P. Morgan, Mr. Glyphis led the origination and execution of transactions including initial public offerings, equity follow-on offerings, high yield and investment grade bond offerings, corporate mergers and acquisitions, asset acquisition and divestitures, and reserve-based and corporate lending. Mr. Glyphis earned his B.A. in History from the University of Virginia.

Sean R. Smith has been our Chief Operating Officer since the closing of the Business Combination. Mr. Smith has served as the Vice President, Geosciences of CRP since May 2014. Prior to joining CRP, from February 2013 to May 2014, Mr. Smith worked at QEP Resources, where he served in several roles, including as a General Manager, leading the geoscience, regulatory and reservoir engineering departments for the Williston, Powder River, and Denver Julesburg Basins. Prior to QEP Resources, from 2005 to February 2013, Mr. Smith worked at Resolute Energy Corporation as a Manager and Geologist. He has also worked in various geotechnical roles at Kerr-McGee and Sanchez Oil & Gas. Mr. Smith earned his B.A. in Geology from Lawrence University. He is licensed with the Texas Board of Professional Geoscientists and is a member of the American Association of Petroleum Geologists.

Maire A. Baldwin has served as a director since the closing of the Business Combination. Ms. Baldwin was employed as an Advisor to EOG from March 2015 until April 2016. Prior to that, she was employed at EOG as Vice President Investor Relations from 1996-2014. Ms. Baldwin has served as a director of the Houston Parks Board since 2011, a non-profit dedicated to developing parks and green space to the greater Houston area where she serves on several committees. She is co-founder of Pursuit, a non-profit dedicated to raising funds and awareness of adults with intellectual and developmental disabilities. Ms. Baldwin has an MBA from the University of Texas at Austin and a B.A. in Economics from the University of Texas at Austin. Ms. Baldwin was selected to serve on the board of directors due to her extensive experience in the energy industry.

Robert M. Tichio has served as a director since the closing of the Business Combination. Mr. Tichio is a Partner of Riverstone and joined Riverstone in 2006. Prior to joining Riverstone, Mr. Tichio was in the Principal Investment Area of Goldman Sachs which manages the firm's private corporate equity investments. Mr. Tichio began his career at J.P. Morgan in the Mergers & Acquisitions group where he concentrated on assignments that included public company combinations, asset sales, takeover defenses and leveraged buyouts. In addition to serving on the boards of a number of Riverstone portfolio companies and their affiliates, Mr. Tichio has been a director of Northern Blizzard Resources Inc. since June 2011 and a director EP Energy Corporation since September 2013. Mr. Tichio previously served as a member of the board of directors of Gibson Energy (TSE:GEI) from 2008 to 2013 and Midstates Petroleum Company, Inc. from 2012 to 2015. He holds an MBA from Harvard Business School and a bachelor's degree from Dartmouth College. Mr. Tichio was selected to serve on the board of directors due to his extensive private equity and mergers and acquisitions experience.

Karl E. Bandtel has served as a director since the closing of the Business Combination. Mr. Bandtel was a Partner at Wellington Management Company, where he managed energy portfolios, from 1997 until June 30, 2016 when he retired. He holds a Master's degree in business from the University of Wisconsin-Madison and a bachelor's degree from University of Wisconsin-Madison. Mr. Bandtel was selected to serve on the board of directors due to his extensive experience in investing in energy companies, both public and private.

Jeffrey H. Tepper has served as a director since the completion of our IPO in February 2016. Mr. Tepper is Founder of JHT Advisors LLC, an M&A advisory and investment firm. From 1990 to 2013, Mr. Tepper served in a variety of senior management and operating roles at the investment bank Gleacher & Company, Inc. and its predecessors and affiliates. Mr. Tepper was Head of Investment Banking and a member of the Firm's Management Committee. Mr. Tepper is also the former Chief Operating Officer overseeing operations, compliance, technology and financial reporting. In 2001, Mr. Tepper co-founded Gleacher's asset management activities and served as President. Gleacher managed over $1 billion of institutional capital in the mezzanine capital and fund of hedge fund areas. Mr. Tepper served on the Investment Committees of Gleacher Mezzanine and Gleacher Fund Advisors. Between 1987 and 1990, Mr. Tepper was employed by Morgan Stanley & Co. as a financial analyst in the mergers & acquisitions and merchant banking departments. Mr. Tepper received an MBA from Columbia Business School and a BS in Economics from The Wharton School of the University of Pennsylvania with concentrations in finance and accounting. Mr. Tepper is experienced in mergers & acquisitions, corporate finance, leveraged finance and asset management. Mr. Tepper was selected to serve on the board of directors due to his significant investment and financial experience.

David M. Leuschen has served as a director since the closing of the Business Combination. Mr. Leuschen is a Founder of Riverstone and has been a Senior Managing Director since 2000. Prior to founding Riverstone, Mr. Leuschen was a Partner and Managing Director at Goldman Sachs and founder and head of the Goldman Sachs Global Energy and Power Group. Mr. Leuschen joined Goldman Sachs in 1977, became head of the Global Energy and Power Group in 1985, became a Partner of that firm in 1986 and remained with Goldman Sachs until leaving to found Riverstone in 2000. Mr. Leuschen also served as Chairman of the Goldman Sachs Energy Investment Committee, where he was responsible for screening potential capital commitments by Goldman Sachs in the energy and power industry and was responsible for establishing and managing the firm's relationships with senior executives from leading companies in all segments of the energy and power industry. Mr. Leuschen serves as a non-executive board member of Riverstone Energy Limited (LSE: REL) since May 2013 and serves on the boards of directors or equivalent bodies of a number of private Riverstone portfolio companies and their affiliates. In 2007, Mr. Leuschen, along with Riverstone and The Carlyle Group ("Carlyle"), became the subject of an industry-wide inquiry by the Office of the Attorney General of the State of New York (the "Attorney General") relating to the use of placement agents in connection with investments by the New York State Common Retirement Fund ("NYCRF") in certain funds, including funds that were jointly developed by Riverstone and Carlyle. In June 2009, Riverstone entered into an Assurance of Discontinuance with the Attorney General to resolve the matter and agreed to make a restitution payment of $30 million to the New York State Office of the Attorney General for the benefit of NYCRF. Mr. Leuschen also entered into an Assurance of Discontinuance with the Attorney General in December 2009 and agreed that Riverstone and/or Mr. Leuschen would make a restitution payment of $20 million to the New York State Office of the Attorney General for the benefit of NYCRF. Mr. Leuschen has received an MBA from Dartmouth's Amos Tuck School of Business and an A.B. degree from Dartmouth College. Mr. Leushen was selected to serve on the board of directors due to his extensive mergers and acquisitions, financing and investing experience in the energy and power industry.

Pierre F. Lapeyre, Jr. has served as a director since the closing of the Business Combination. Mr. Lapeyre is a Founder of Riverstone and has been a Senior Managing Director since 2000. Prior to founding Riverstone, Mr. Lapeyre was a Managing Director of Goldman Sachs in its Global Energy and Power Group. Mr. Lapeyre joined Goldman Sachs in 1986 and spent his 14-year investment banking career focused on energy and power, particularly the midstream, upstream and energy service sectors. Mr. Lapeyre serves as a non-executive board member of Riverstone Energy Limited (LSE: REL) since May 2013 and serves on the boards of directors or equivalent bodies of a number of private Riverstone portfolio companies and their affiliates. He has an MBA from the University of North Carolina at Chapel Hill and a B.S. in Finance and Economics from the University of Kentucky. Mr. Lapeyre was selected to serve on the board of directors due to his extensive mergers and acquisitions, financing and investing experience in the energy and power industry.

Tony R. Weber has served as a director since the closing of the Business Combination. Mr. Weber currently serves as Managing Partner and Chairman of the Executive Committee for NGP. Prior to joining NGP in December 2003, Mr. Weber was the Chief Financial Officer of Merit Energy Company from April 1998 to December 2003. Prior to that, he was Senior Vice President and Manager of Union Bank of California's Energy Division in Dallas, Texas from 1987 to 1998. Mr. Weber served as Chairman of the Board for Memorial Resource Development, Inc. ("MRD") from its formation in January 2014 until MRD was acquired by Range Resources Corporation in September 2016. In addition, Mr. Weber served as a director of the general partner of Memorial Production Partners LP from December 2011 to March 2016. Mr. Weber currently serves as a member of the Board of Directors for WildHorse Resource Development Corporation. Further, in his role at NGP, Mr. Weber serves on numerous private company boards as well as industry groups, including the IPAA Capital Markets Committee and Dallas Wildcat Committee. He currently serves on the Dean's Council of the Mays Business School at Texas A&M University and was a founding member of the Mays Business Fellows Program. Mr. Weber was selected to serve on the board of directors due to his extensive corporate finance, banking and private equity experience.

Board of Directors and Terms of Office of Officers and Directors

We are managed under the direction of our board of directors. Our board of directors is divided into three classes of directors with only one class of directors being elected in each year and each class (except those directors appointed prior to our first annual meeting of stockholders) serving a three-year term. The term of office of the first class of directors, consisting of Maire A. Baldwin and Robert M. Tichio, will expire at our first annual meeting of stockholders. The term of office of the second class of directors, Jeffrey H. Tepper and Karl E. Bandtel, will expire at the second annual meeting of stockholders. The term of office of the third class of directors, consisting of Mark G. Papa, David M. Leuschen and Pierre F. Lapeyre, Jr., will expire at the third annual meeting of stockholders. In addition, one director, initially Tony R. Weber, will be nominated and elected by CRD as the holder of our Series A Preferred Stock. The term of office of Mr. Weber will expire at our first annual meeting of stockholders.

Our board of directors has determined that Ms. Maire A. Baldwin and Messrs. Karl E. Bandtel, Jeffrey H. Tepper and Tony R. Weber are independent within the meaning of NASDAQ Rule 5605(a)(2).

Officers are appointed by the board of directors and serve at discretion of the board, rather than for specific terms of office.

Controlled Company Status

Effective as of December 28, 2016, Riverstone and its affiliates, including our Sponsor, no longer control a majority of our outstanding voting common stock. As a result, we are no longer a "controlled company" within the meaning of the NASDAQ listing rules, and will no longer be able to take advantage of exemptions from certain corporate governance requirements. Specifically, pursuant to the requirements of the NASDAQ listing rules, a majority of our board of directors must consist of independent directors within one year after we cease to be a controlled company, and we must comply with the independent board committee requirements as they relate to the nominating and corporate governance and compensation committees on the following phase-in schedule: (1) one independent committee member at the time we cease to be a controlled company, (2) a majority of independent committee members within 90 days of the date we cease to be a controlled company and (3) all independent committee members within one year of the date we cease to be a controlled company. Our board of directors is not currently comprised of a majority of independent directors, and neither our nominating and corporate governance committee nor our compensation committee is currently comprised solely of independent directors.

Board Committees

The standing committees of our board of directors currently consists of an audit committee (the "Audit Committee"), a compensation committee (the "Compensation Committee") and a nominating and corporate governance committee (the "Nominating and Corporate Governance Committee"). Each of the committees report to the board of directors as they deem appropriate and as the board may request. The composition, duties and responsibilities of these committees are set forth below.

Audit Committee

The principal functions of our Audit Committee are detailed in the Audit Committee charter, which is available on our website, and include:

- the appointment, compensation, retention, replacement, and oversight of the work of the independent auditors and any other independent registered public accounting firm engaged by us;
- pre-approving all audit and permitted non-audit services to be provided by the independent auditors or any other registered public accounting firm engaged us, and establishing pre-approval policies and procedures;
- reviewing and discussing with the independent auditors all relationships the auditors have with us in order to evaluate their continued independence;
- setting clear hiring policies for employees or former employees of the independent auditors;
- setting clear policies for audit partner rotation in compliance with applicable laws and regulations;
- obtaining and reviewing a report, at least annually, from the independent auditors describing (i) the independent auditor's internal quality-control procedures and (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the audit firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm and any steps taken to deal with such issues;
- reviewing and approving any related party transaction required to be disclosed pursuant to Item 404 of Regulation S-K promulgated by the SEC prior to us entering into such transaction; and
- reviewing with management, the independent auditors and our legal advisors, as appropriate, any legal, regulatory or compliance matters, including any correspondence with regulators or government agencies and any employee complaints or published reports that raise material issues regarding our financial statements or accounting policies and any significant changes in accounting standards or rules promulgated by the Financial Accounting Standards Board, the SEC or other regulatory authorities.

Our Audit Committee consists of Messrs. Jeffrey H. Tepper and Karl E. Bandtel and Ms. Maire A. Baldwin, with Mr. Tepper serving as the Chair. We believe that Messrs. Tepper and Bandtel and Ms. Baldwin qualify as independent directors according to the rules and regulations of the SEC with respect to audit committee membership. We also believe that Mr. Tepper qualifies as our "audit committee financial expert," as such term is defined in Item 401(h) of Regulation S-K.

Compensation Committee

The principal functions of our Compensation Committee are detailed in the Compensation Committee charter, which is available on our website, and include:

- reviewing and approving on an annual basis the corporate goals and objectives relevant to our Chief Executive Officer's compensation, evaluating our Chief Executive Officer's performance in light of such goals and objectives and determining and approving the remuneration (if any) of our Chief Executive Officer based on such evaluation;
- reviewing and approving on an annual basis the compensation of all of our other officers;
- reviewing on an annual basis our executive compensation policies and plans;
- implementing and administering our incentive compensation equity-based remuneration plans;
- assisting management in complying with our proxy statement and annual report disclosure requirements;
- approving all special perquisites, special cash payments and other special compensation and benefit arrangements for our officers and employees;
- if required, producing a report on executive compensation to be included in our annual proxy statement; and
- reviewing, evaluating and recommending changes, if appropriate, to the remuneration for directors.

Our Compensation Committee consists of Ms. Maire A. Baldwin and Messrs. Pierre F. Lapeyre, Jr., Jeffrey H. Tepper and Robert M. Tichio, with Mr. Lapeyre serving as the Chair.

The Compensation Committee may delegate the approval of certain transactions to a subcommittee consisting solely of two or more members of the Compensation Committee who are "non-employee directors" for the purposes of Rule 16b-3 under the Exchange Act and "outside directors" for the purposes of Section 162(m) of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). On October 27, 2016, the Compensation Committee created a subcommittee (the "Section 162(m) Plan Subcommittee") consisting of Ms. Baldwin and Mr. Tepper to administer and make determinations from time to time with respect to awards granted or compensation to be provided under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (the "LTIP") or any successor plan, including compensation that is intended to qualify as "performance-based compensation" under Section 162(m) of the Code, and the regulations promulgated thereunder. The Compensation Committee has determined that Ms. Baldwin and Mr. Tepper are both “non-employee directors” for the purposes of Rule 16b-3 under the Exchange Act and “outside directors” for the purposes of Section 162(m) of the Code. The charter of the Section 162(m) Plan Subcommittee is available on our website.

Nominating and Corporate Governance Committee

The principal functions of our Nominating and Corporate Governance Committee are detailed in the Nominating and Corporate Governance Committee charter, which is available on our website, and include:

- assisting the board of directors in identifying individuals qualified to become members of the board of directors, consistent with criteria approved by the board of directors;
- recommending director nominees for election or for appointment to fill vacancies;
- recommending the election of officer candidates;
- monitoring the independence of board of director members;
- ensuring the availability of director education programs; and
- advising the board of directors about appropriate composition of the board of directors and its committees.

The Nominating and Corporate Governance Committee also develops and recommends to the board of directors corporate governance principles and practices and assists in implementing them, including conducting a regular review of our corporate governance principles and practices. The Nominating and Corporate Governance Committee oversees the annual performance evaluation of the board of directors and the committees of the board of directors and makes a report to the board of directors on succession planning.

Our Nominating and Corporate Governance Committee consists of Messrs. David M. Leuschen, Tony R. Weber and Robert M. Tichio, with Mr. Leuschen serving as the Chair.

Section 16(a) Beneficial Ownership Reporting Compliance

The executive officers and directors of the Company and persons who own more than 10% of the Company’s common stock are required to file reports with the SEC, disclosing the amount and nature of their beneficial ownership in common stock, as well as changes in that ownership. Based solely on its review of reports and written representations that the Company has received, the Company believes that the Company’s directors, officers and 10% holders of common stock complied with all filing requirements during the fiscal year ended December 31, 2016.

ITEM 11. EXECUTIVE COMPENSATION

Executive Compensation

The following disclosure describes the material elements of the compensation of the Company’s named executive officers for the fiscal year ended December 31, 2016 and is presented based on the reduced disclosure rules applicable to the Company as an “emerging growth company” within the meaning of the Securities Act. For the fiscal year ended December 31, 2016, our named executive officers were:

- Mark G. Papa, President and Chief Executive Officer;
- George S. Glyphis, Chief Financial Officer; and
- Sean R. Smith, Chief Operating Officer.

Mr. Papa has been our Chief Executive Officer and a director since November 2015 and has served as our President since the closing of the Business Combination. Prior to the closing of the Business Combination, we did not pay Mr. Papa any compensation for services rendered to us. During 2016 and through the closing of the Business Combination, Messrs. Glyphis and Smith were employees of CRD or one of its affiliates. Since the closing of the Business Combination, Mr. Glyphis has served as our Chief Financial Officer and Mr. Smith has served as our Chief Operating Officer.

2016 Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)(2)	Option Awards ($)(3)	All Other Compensation ($)(4)	Total ($)
Mark G. Papa, President and Chief Executive Officer (1)	2016	148,485	1,500,000	5,860,000	—	7,508,485
George S. Glyphis, Chief Financial Officer	2016	293,087	481,250	1,465,000	13,583	2,252,920
	2015	275,000	68,750	—	25,077	368,827
Sean R. Smith, Chief Operating Officer	2016	308,469	529,375	1,758,000	13,708	2,609,552

(1) Although Mr. Papa has been our Chief Executive Officer and a director since November 2015, he did not receive any compensation from us until after the closing of the Business Combination.

(2) Amounts for 2016 represent discretionary bonuses awarded in recognition of 2016 performance. Forty percent of the amount disclosed for each named executive officer was paid in the form of restricted shares of our Class A Common Stock that will vest in three substantially equal annual installments on each of the first three anniversaries of February 7, 2017, subject to the executive's continued service. For purposes of valuing these restricted stock awards, the Class A Common Stock was assumed to have a value of $18.35 per share. The grant date value of the restricted stock award received by each named executive officer, calculated using the $18.81 per share closing price of our Class A Common Stock on the date of grant, was $615,050 for Mr. Papa, $197,317 for Mr. Glyphis and $217,067 for Mr. Smith.

(3) Amounts in this column reflect the aggregate grant date fair value of stock options granted during 2016 computed in accordance with ASC Topic 718, excluding the effect of estimated forfeitures. All of the stock options have an exercise price of $14.52, which was the closing price of our Class A Common Stock on the date of grant. We calculated the grant date fair value of the stock options using a Black-Scholes option pricing model and the following assumptions: a volatility of 40%, an option term of six years, a risk-free interest rate of 1.5%, a dividend yield of zero and a grant date fair value of our Class A Common Stock of $5.86.

(4) Amounts in this column reflect, for all named executive officers, matching contributions to the 401(k) Plan made on their behalf for 2015 and 2016. See "-Narrative Disclosures-Retirement Benefits" for more information on matching contributions to the 401(k) Plan.

Outstanding Equity Awards at 2016 Fiscal Year-End

		Option Awards			
Name	Grant Date	Number of Securities Underlying Unexercised Options, Exercisable	Number of Securities Underlying Unexercised Options, Unexercisable(1)	Option Exercise Price	Option Expiration Date
Mark G. Papa	10/27/16	—	1,000,000	$ 14.52	10/26/26
George S. Glyphis	10/27/16	—	250,000	$ 14.52	10/26/26
Sean R. Smith	10/27/16	—	300,000	$ 14.52	10/26/26

(1) All options vest in three substantially equal annual installments on each of the first three anniversaries of the grant date, subject to the holder's continued employment with us through the applicable vesting date.

Narrative Disclosures

Base Salaries and Annual Bonuses

Although Mr. Papa has been our Chief Executive Officer and a director since November 2015, he did not receive any compensation from us until after the closing of the Business Combination. During 2016 and through the closing of the Business Combination, Messrs. Glyphis and Smith had annual base salaries of $275,000 and $283,250 respectively. Effective as of the closing of the Business Combination, the Compensation Committee approved an annual base salary for Mr. Papa and annual base salaries and annual target bonuses (expressed as a percentage of annual base salary) for Messrs. Glyphis and Smith, as set forth in the following table:

Named Executive Officer	Annual Base Salary ($)	Target Bonus (%)
Mark G. Papa	800,000	N/A(1)
George S. Glyphis	350,000	100
Sean R. Smith	385,000	100

(1) The Compensation Committee of the Board has not established a specific bonus target percentage for Mr. Papa and has discretion in determining his year-end bonus.

Equity Compensation

In connection with the closing of the Business Combination, our board of directors adopted and our stockholders approved the LTIP, which is described below under "2016 Long Term Incentive Plan." On October 27, 2016, our Section 162(m) Plan Subcommittee granted Messrs. Papa, Glyphis and Smith options to purchase 1,000,000, 250,000 and 300,000 shares of our Class A Common Stock, respectively, under the LTIP at an exercise price per share of $14.52, which was the closing price of our Class A Common Stock on the date of grant. The options will vest and become exercisable in three substantially equal annual installments on each of the first three anniversaries of the date of grant, subject to the executive officer's continued service with us.

Compensation of our Chief Executive Officer

Mr. Papa is an advisor to Riverstone. We currently anticipate Mr. Papa will spend approximately 60% of his working time providing services for us as our President and Chief Executive Officer and approximately 40% of his working time providing services to Riverstone on matters unrelated to the Company. Since the closing of the Business Combination, this has been the approximate allocation of Mr. Papa's working time. The Compensation Committee and the Section 162(m) Plan Subcommittee were aware of Mr. Papa's continued service to Riverstone and considered it when determining an appropriate level of compensation for services as our President and Chief Executive Officer.

Employment, Severance or Change in Control Agreements

The Company has not entered into any employment, severance or change in control agreements with its named executive officers. In addition, the Company's named executive officers are not entitled to any payments or other benefits in connection with a termination of employment or a change in control.

Retirement Benefits

Our named executive officers are eligible to participate in our employee benefit plans and programs, including medical and dental benefits and life insurance, to the same extent as our other full-time employees, subject to the terms and eligibility requirements of those plans. We also sponsor a 401(k) defined contribution plan (the "401(k) Plan") in which our named executive officers may participate, subject to limits imposed by the Code, to the same extent as our other full-time employees. The 401(k) Plan provides for matching contributions equal to 100% of the first 6% of employees' eligible compensation contributed to the 401(k) Plan. Employees are immediately 100% vested in the matching contributions. We do not typically provide any perquisites or special personal benefits to our named executive officers, but have from time to time reimbursed relocation expenses for our named executive officers.

Compensation of Directors

Prior to the closing of the Business Combination, our directors received no compensation for their service on our board of directors. Since the closing of the Business Combination, directors employed by us or affiliated with Riverstone or NGP Energy Capital Management have continued to receive no compensation for serving on our board of directors or its committees. Effective October 11, 2016, our board of directors approved for each of Maire A. Baldwin, Karl E. Bandtel and Jeffrey H. Tepper an annual retainer of $87,500 per year in cash for service on our board of directors and its committees, payable quarterly in arrears and subject to proration for any partial year of service. In addition, our board of directors granted each of Ms. Baldwin and Messrs. Bandtel and Tepper 11,218 restricted shares of our Class A Common Stock under the LTIP, which will vest in a single installment on October 11, 2017. The board of directors anticipates that it will consider additional annual awards of restricted shares under our LTIP in the future that are intended to result in a total annual value of cash and equity-based compensation of approximately $250,000 being paid to Ms. Baldwin and Messrs. Bandtel and Tepper for service on our board of directors.

2016 Director Compensation Table

Name	Fees earned or paid in cash ($)	Stock awards ($)(1)	Total ($)
Maire A. Baldwin	19,658	224,677	244,335
Karl E. Bandtel	19,658	224,677	244,335
Jeffrey H. Tepper	19,658	224,677	244,335
Robert M. Tichio	—	—	—
David M. Leuschen	—	—	—
Pierre F. Lapeyre, Jr.	—	—	—
Tony R. Weber	—	—	—
William D. Gutermuth(2)	—	—	—
Diana J. Walters(2)	—	—	—

(1) Amounts in this column reflect the aggregate grant date fair value of restricted shares computed in accordance with ASC Topic 718. Each of Ms. Baldwin and Messrs. Bandtel and Tepper held 11,218 unvested shares of our restricted stock as of December 31, 2016. None of our non-employee directors held any of our stock options or other equity awards as of such date.

(2) Mr. Gutermuth and Ms. Walters resigned from our board of directors effective as of the closing of the Business Combination.

2016 Long Term Incentive Plan

In connection with the closing of the Business Combination, our board of directors adopted and our stockholders approved the LTIP, under which we may grant cash and equity-based incentive awards to eligible service providers in order to attract, retain and motivate the persons who make important contributions to our company. The material terms of the LTIP are summarized below.

Eligibility and Administration

Our employees, consultants and directors, and employees and consultants of our subsidiaries, are eligible to receive awards under the LTIP. The LTIP is administered by our board of directors, which may delegate its duties and responsibilities to one or more committees of our directors and/or officers (referred to collectively as the "plan administrator"), subject to the limitations imposed under the LTIP, Section 16 of the Exchange Act, stock exchange rules and other applicable laws. The plan administrator has the authority to take all actions and make all determinations under the LTIP, to interpret the LTIP and award agreements and to adopt, amend and repeal rules for the administration of the LTIP as it deems advisable. The plan administrator also has the authority to determine which eligible service providers receive awards, grant awards and set the terms and conditions of all awards under the LTIP, including any vesting and vesting acceleration provisions, subject to the conditions and limitations in the LTIP. Our board of directors has delegated certain limited authority to our Chief Executive Officer to grant options and awards of restricted stock under the LTIP and created the 162(m) Plan Subcommittee to administer and make determinations from time to time with respect to awards granted or compensation to be provided under the LTIP.

Shares Available for Awards

An aggregate of 16,500,000 shares of Class A Common Stock have been reserved for issuance under the LTIP, all of which may be issued upon the exercise of incentive stock options. Shares issued under the LTIP may be authorized but unissued shares, shares purchased on the open market or treasury shares. As of March 7, 2017, a total of 3,919,500 stock options and 470,226 shares of restricted stock were outstanding under the LTIP.

If an award under the LTIP expires, lapses or is terminated, exchanged for cash, surrendered, repurchased, canceled without having been fully exercised or forfeited, any unused shares subject to the award will again be available for new grants under the LTIP. Further, shares delivered to satisfy the purchase price or tax withholding obligation for any award other than an option or stock appreciation right will again be available for new grants under the LTIP. However, the LTIP does not allow the shares available for grant under the LTIP to be recharged or replenished with shares that:

- are tendered or withheld to satisfy the exercise price of an option;
- are tendered or withheld to satisfy tax withholding obligations for any award that is an option or stock appreciation right;
- are subject to a stock appreciation right but are not issued in connection with the stock settlement of the stock appreciation right; or
- are purchased on the open market with cash proceeds from the exercise of options.

Awards granted under the LTIP in substitution for any options or other stock or stock-based awards granted by an entity before the entity's merger or consolidation with us (or any of our subsidiaries) or our (or any of our subsidiary's) acquisition of the entity's property or stock will not reduce the shares available for grant under the LTIP, but will count against the maximum number of shares that may be issued upon the exercise of incentive stock options.

Individual Award Limits

The maximum aggregate number of shares of Class A Common Stock with respect to which one or more awards of options or stock appreciation rights may be granted under the LTIP to any one person during any fiscal year is 1,000,000 shares of Class A Common Stock; and the maximum aggregate number of shares of Class A Common Stock with respect to which one or more awards of restricted stock, restricted stock units, or other stock or cash based awards that are denominated in shares intended to qualify as performance-based compensation under Section 162(m) of the Code (as described below) may be granted under the LTIP to any one person during any fiscal year is 1,000,000 shares of Class A Common Stock. However, these numbers may be adjusted to take into account equity restructurings and certain other corporate transactions as described below. The maximum amount of cash that may be paid to any one person during any fiscal year with respect to one or more awards payable in cash and not denominated in shares is $5,000,000.

Awards

The LTIP provides for the grant of stock options, including incentive stock options ("ISOs") and nonqualified stock options ("NSOs"), stock appreciation rights ("SARs"), restricted stock, dividend equivalents, restricted stock units ("RSUs") and other stock or cash based awards. Certain awards under the LTIP may constitute or provide for payment of "nonqualified deferred compensation" under Section 409A of the Code. All awards under the LTIP will be set forth in award agreements, which will detail the terms and conditions of awards, including any applicable vesting and payment terms and post-termination exercise limitations. A brief description of each award type follows.

- *Stock Options and SARs.* Stock options provide for the purchase of shares of Class A Common Stock in the future at an exercise price set on the grant date. ISOs, in contrast to NSOs, may provide tax deferral beyond exercise and favorable capital gains tax treatment to their holders if certain holding period and other requirements of the Code are satisfied. SARs entitle their holder, upon exercise, to receive from us an amount equal to the appreciation of the shares subject to the award between the grant date and the exercise date. The plan administrator will determine the number of shares covered by each option and SAR, the exercise price of each option and SAR and the conditions and limitations applicable to the exercise of each option and SAR. The exercise price of a stock option or SAR will not be less than 100% of the fair market value of the underlying share on the grant date (or 110% in the case of ISOs granted to certain significant stockholders), except with respect to certain substitute awards granted in connection with a corporate transaction. The term of a stock option or SAR may not be longer than ten years (or five years in the case of ISOs granted to certain significant stockholders).
- *Restricted Stock.* Restricted stock is an award of nontransferable shares of Class A Common Stock that remain forfeitable unless and until specified conditions are met and which may be subject to a purchase price. Upon issuance of restricted stock, recipients generally have the rights of a stockholder with respect to such shares, which generally include the right to receive dividends and other distributions in relation to the award; however, dividends may be paid with respect to restricted stock with performance-based vesting only to the extent the performance conditions have been satisfied and the restricted stock vests. The terms and conditions applicable to restricted stock will be determined by the plan administrator, subject to the conditions and limitations contained in the LTIP.
- *RSUs.* RSUs are contractual promises to deliver shares of Class A Common Stock in the future, which may also remain forfeitable unless and until specified conditions are met and may be accompanied by the right to receive the equivalent value of dividends paid on shares of Class A Common Stock prior to the delivery of the underlying shares (i.e., dividend equivalent rights); however, dividend equivalents with respect to an award with performance-based vesting that are based on dividends paid prior to the vesting of such award will only be paid out to the holder to the extent that the performance-based vesting conditions are subsequently satisfied and the award vests. The plan administrator may provide that the delivery of the shares underlying RSUs will be deferred on a mandatory basis or

at the election of the participant. The terms and conditions applicable to RSUs will be determined by the plan administrator, subject to the conditions and limitations contained in the LTIP.

- *Other Stock or Cash Based Awards.* Other stock or cash based awards are awards of cash, fully vested shares of Class A Common Stock and other awards valued wholly or partially by referring to, or otherwise based on, shares of Class A Common Stock or other property. Other stock or cash based awards may be granted to participants and may also be available as a payment form in the settlement of other awards, as standalone payments and as payment in lieu of compensation to which a participant is otherwise entitled. The plan administrator will determine the terms and conditions of other stock or cash based awards, which may include any purchase price, performance goal, transfer restrictions and vesting conditions.

Performance-Based Awards

The plan administrator will determine whether specific performance awards are intended to constitute "qualified performance-based compensation" within the meaning of Section 162(m) of the Code and will have discretion to pay compensation that is not qualified performance-based compensation and that is not tax deductible. Under Section 162(m), a "covered employee" is our Chief Executive Officer and certain of our other most highly compensated executive officers. Section 162(m) imposes a $1 million cap on the compensation deduction that we may take in respect of compensation paid to covered employees; however, compensation that qualifies as qualified performance-based compensation is excluded from the calculation of the $1 million cap.

In order to constitute qualified performance-based compensation under Section 162(m), in addition to certain other requirements, the relevant amounts must be payable only upon the attainment of pre-established, objective performance goals set by the plan administrator and based on stockholder-approved performance criteria. Our stockholders have approved the below performance criteria.

For purposes of the LTIP, one or more of the following performance criteria will be used in setting performance goals applicable to qualified performance-based compensation, either for the entire company or a subsidiary, division, business unit or an individual, and may be used in setting performance goals applicable to other stock or cash based awards: net earnings or losses (either before or after one or more of interest, taxes, depreciation, amortization, and non-cash equity-based compensation expense); gross or net sales or revenue or sales or revenue growth; net income (either before or after taxes) or adjusted net income; profits (including but not limited to gross profits, net profits, profit growth, net operation profit or economic profit), profit return ratios or operating margin; budget or operating earnings (either before or after taxes or before or after allocation of corporate overhead and bonus); cash flow (including operating cash flow and free cash flow or cash flow return on capital); return on assets; return on capital or invested capital; cost of capital; return on stockholders' equity; total stockholder return; return on sales; costs, reductions in costs and cost control measures; expenses; working capital; earnings or loss per share; adjusted earnings or loss per share; price per share or dividends per share (or appreciation in or maintenance of such price or dividends); regulatory achievements or compliance; implementation, completion or attainment of objectives relating to research, development, regulatory, commercial, or strategic milestones or developments; market share; economic value or economic value added models; division, group or corporate financial goals; individual business objectives; production or growth in production; reserves or added reserves; growth in reserves per share; inventory growth; environmental, health and/or safety performance; effectiveness of hedging programs; improvements in internal controls and policies and procedures; customer satisfaction/growth; customer service; employee satisfaction; recruitment and maintenance of personnel; human resources management; supervision of litigation and other legal matters; strategic partnerships and transactions; financial ratios (including those measuring liquidity, activity, profitability or leverage); debt levels or reductions; sales-related goals; financing and other capital raising transactions; cash on hand; acquisition activity; investment sourcing activity; and marketing initiatives, any of which may be measured in absolute terms or as compared to any incremental increase or decrease. Such performance goals also may be based solely by reference to the company's performance or the performance of a subsidiary, division, business segment or business unit of the company or a subsidiary, or based upon performance relative to performance of other companies or upon comparisons of any of the indicators of performance relative to performance of other companies. When determining performance goals, the plan administrator may provide for exclusion of the impact of an event or occurrence which the plan administrator determines should appropriately be excluded, including, without limitation, non-recurring charges or events, acquisitions or divestitures, changes in the corporate or capital structure, events unrelated to the business or outside of the control of management, foreign exchange considerations, and legal, regulatory, tax or accounting changes.

Prohibition on Repricing

Under the LTIP, the plan administrator may not except in connection with equity restructurings and certain other corporate transactions as described below, without the approval of our stockholders, authorize the repricing of any outstanding option or SAR to reduce its price per share, or cancel any option or SAR in exchange for cash or another award when the price per share exceeds the Fair Market Value (as that term is defined in the LTIP) of the underlying shares.

Certain Transactions

In connection with certain corporate transactions and events affecting our Class A Common Stock, including a change in control, or change in any applicable laws or accounting principles, the plan administrator has broad discretion to take action under the LTIP to prevent the dilution or enlargement of intended benefits, facilitate the transaction or event or give effect to the change in applicable laws or accounting principles. This includes canceling awards for cash or property, accelerating the vesting of awards, providing for the assumption or substitution of awards by a successor entity, adjusting the number and type of shares subject to outstanding awards and/or with respect to which awards may be granted under the LTIP and replacing or terminating awards under the LTIP. In addition, in the event of certain non-reciprocal transactions with our stockholders, the plan administrator will make equitable adjustments to the LTIP and outstanding awards as it deems appropriate to reflect the transaction.

Provisions of the LTIP Relating to Director Compensation

The LTIP provides that the plan administrator may establish compensation for non-employee directors from time to time subject to the LTIP's limitations. The plan administrator will from time to time determine the terms, conditions and amounts of all non-employee director compensation in its discretion and pursuant to the exercise of its business judgment, taking into account such factors, circumstances and considerations as it shall deem relevant from time to time, provided that the sum of any cash compensation or other compensation and the grant date fair value of any equity awards granted under the LTIP as compensation for services as a non-employee director during any fiscal year may not exceed $500,000. The plan administrator may make exceptions to this limit for individual non-employee directors in extraordinary circumstances, as the plan administrator may determine in its discretion, subject to the limitations in the LTIP.

Plan Amendment and Termination

Our board of directors may amend or terminate the LTIP at any time; however, no amendment, other than an amendment that increases the number of shares available under the LTIP, may materially and adversely affect an award outstanding under the LTIP without the consent of the affected participant and stockholder approval will be obtained for any amendment to the extent necessary to comply with applicable laws. The LTIP will remain in effect until the tenth anniversary of the date our board of directors adopted the LTIP, unless earlier terminated by our board of directors. No awards may be granted under the LTIP after its termination.

Foreign Participants, Claw-back Provisions, Transferability and Participant Payments

The plan administrator may modify awards granted to participants who are foreign nationals or employed outside the United States or establish subplans or procedures to address differences in laws, rules, regulations or customs of such foreign jurisdictions. All awards will be subject to any company claw-back policy as set forth in such claw-back policy or the applicable award agreement. Except as the plan administrator may determine or provide in an award agreement, awards under the LTIP are generally non-transferrable, except by will or the laws of descent and distribution, or, subject to the plan administrator's consent, pursuant to a domestic relations order, and are generally exercisable only by the participant. With regard to tax withholding obligations arising in connection with awards under the LTIP, and exercise price obligations arising in connection with the exercise of stock options under the LTIP, the plan administrator may, in its discretion, accept cash, wire transfer or check, shares of Class A Common Stock that meet specified conditions, a promissory note, a "market sell order," such other consideration as the plan administrator deems suitable or any combination of the foregoing.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2016, no officer or employee served as a member of our Compensation Committee. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving on our board of directors or Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information known to us regarding ownership of shares of our voting common stock as of March 7, 2017 by:

- each person who is the beneficial owner of more than 5% of the outstanding shares of our voting common stock;
- each of our named executive officers and directors; and
- all of our current executive officers and directors, as a group.

Beneficial ownership is determined according to the rules of the SEC, which generally provide that a person has beneficial ownership of a security if he, she or it possesses sole or shared voting or investment power over that security, including options and warrants that are currently exercisable or exercisable within 60 days.

The beneficial ownership of our voting common stock is based on 221,038,003 shares of our voting common stock issued and outstanding in the aggregate as of March 7, 2017.

Unless otherwise indicated, we believe that all persons named in the table below have sole voting and investment power with respect to all shares of voting common stock beneficially owned by them.

Name of Beneficial Owner	Number of Shares of Common Stock	Percent of Class
5% or Greater Stockholders		
Funds affiliated with Riverstone Holdings(1)	104,858,590	45.8%
Centennial Resource Development, LLC(2)	12,227,062	5.5%
Funds advised by FMR LLC(3)(4)	25,140,224	11.4%
Celero Energy Company, LP(5)	4,246,898	1.9%
NGP Centennial Follow-On LLC(6)	2,681,961	1.2%
Funds advised by Capital Research and Management Company(7)	16,255,129	7.4%
Funds and accounts advised by T. Rowe Price Associates, Inc.(8)	11,359,106	5.1%
Directors and Named Executive Officers		
Mark G. Papa	43,952	*
George S. Glyphis	10,490	*
Sean R. Smith	11,540	*
Jeffrey H. Tepper	51,218	*
Tony R. Weber	—	—
Robert M. Tichio	—	—
David M. Leuschen(1)	104,858,590	45.8%
Pierre F. Lapeyre Jr.(1)	104,858,590	45.8%
Maire A. Baldwin	11,218	—
Karl E. Bandtel	11,218	—
All directors and executive officers, as a group (10 individuals)	104,998,226	45.8%

* Less than one percent.

(1) Includes 61,743,780 shares of Class A Common Stock held of record by Riverstone VI Centennial QB Holdings, L.P. ("Riverstone QB Holdings"), 18,250,421 shares of Class A Common Stock held of record by REL US Centennial Holdings, LLC ("REL US"), 4,484,389 shares of Class A Common Stock held of record by Riverstone Non-ECI USRPI AIV, L.P. ("Riverstone Non-ECI") and 12,380,000 shares of Class A Common Stock and warrants to purchase an additional 8,000,000 shares of Class A Common Stock held of record by Silver Run Sponsor, LLC ("Silver Run Sponsor"). Does not include an aggregate of 26,100,000 shares of Class A Common Stock (the "Conversion Shares") issuable upon the conversion of 76,304, 22,554 and 5,542 shares of Series B Preferred Stock held of record by Riverstone QB Holdings, REL US and Riverstone Non-ECI, respectively. The conversion of the Series B Preferred Stock into Class A Common Stock is subject to stockholder approval of the issuance of the Conversion Shares pursuant to applicable NASDAQ listing rules. The Company expects to ask stockholders to vote on the approval of the issuance of the Conversion Shares at a Special Meeting of Stockholders to be held in the second quarter of 2017. David Leuschen and Pierre F. Lapeyre, Jr. are the managing directors of Riverstone Holdings LLC. Riverstone Holdings, LLC is the sole shareholder of Riverstone Energy GP VI Corp., which is the managing member of Riverstone Energy GP VI, LLC, which is the general partner of Riverstone Energy Partners VI, L.P., which is the general partner of Riverstone QB Holdings. Riverstone Energy Partners GP VI, LLC is managed by a six person managing committee consisting of Pierre F. Lapeyre, Jr., David M. Leuschen, James T. Hackett, Michael B. Hoffman, N. John Lancaster and, on a rotating basis, one of E. Bartow Jones, Baran Tekkora and Robert M. Tichio. As such, each of Riverstone Energy Partners GP VI, LLC, Riverstone Energy Partners VI, L.P., Riverstone Energy GP VI Corp., Riverstone Holdings LLC, Mr. Leuschen and Mr. Lapeyre may be deemed to share beneficial ownership of the securities held directly by Riverstone QB Holdings. Riverstone Holdings II (Cayman) Ltd. is the general partner of Riverstone Energy Limited Investment Holdings, LP, which is the sole shareholder of REL IP General Partner Limited, which is the general partner of REL IP General Partner LP, which is the managing member of REL US. Mr. Leuschen and Mr. Lapeyre are the sole shareholders of Riverstone Holdings II (Cayman) Ltd. and have or share voting and investment discretion with respect to the securities held of record by REL US Centennial Holdings, LLC. As such, each of REL IP General Partner LP, REL IP General Partner Limited, Riverstone Energy Limited Investment Holdings, LP, Riverstone Holdings II (Cayman) Ltd., Mr. Leuschen and Mr. Lapeyre may be deemed to have or share beneficial ownership of the

securities held directly by REL US. Riverstone Non-ECI GP Ltd. is the sole member of Riverstone Non-ECI Partners GP Cayman LLC, which is the general partner of Riverstone Non-ECI Partners GP (Cayman), L.P., which is the sole member of Riverstone Non-ECI USRPI AIV GP, L.L.C., which is the general partner of Riverstone Non-ECI. Riverstone Non-ECI GP Ltd. is managed by Mr. Leuschen and Mr. Lapeyre, who have or share voting and investment discretion with respect to the securities held of record by Riverstone Non-ECI. As such, each of Riverstone Non-ECI USRPI AIV GP, L.L.C., Riverstone Non-ECI Partners GP (Cayman), L.P., Riverstone Non-ECI Partners GP Cayman LLC, Riverstone Non-ECI GP Ltd., Mr. Leuschen and Mr. Lapeyre may be deemed to have or share beneficial ownership of the securities held directly by Riverstone Non-ECI. Silver Run Sponsor Manager, LLC is the managing member of Silver Run Sponsor. Riverstone Holdings LLC is the managing member of Silver Run Sponsor Manager, LLC. As such, each of Silver Run Sponsor Manager, LLC, Riverstone Holdings LLC, Mr. Leuschen and Mr. Lapeyre may be deemed to share beneficial ownership of the common stock held directly by Silver Run Sponsor, LLC. Each such entity or person disclaims any such beneficial ownership of such securities. The business address for Silver Run Sponsor and Silver Run Sponsor Manager, LLC is 1000 Louisiana Street, Suite 1450, Houston, Texas 77002. The business address for each other person named in this footnote is c/o Riverstone Holdings, 712 Fifth Avenue, 36th Floor, New York, NY 10019.

(2) These accounts are managed by direct or indirect subsidiaries of FMR LLC. Abigail P. Johnson is a Director, the Vice Chairman, the Chief Executive Officer and the President of FMR LLC. Members of the Johnson family, including Abigail P. Johnson, are the predominant owners, directly or through trusts, of Series B voting common shares of FMR LLC, representing 49% of the voting power of FMR LLC. The Johnson family group and all other Series B shareholders have entered into a shareholders' voting agreement under which all Series B voting common shares will be voted in accordance with the majority vote of Series B voting common shares. Accordingly, through their ownership of voting common shares and the execution of the shareholders' voting agreement, members of the Johnson family may be deemed, under the Investment Company Act of 1940, to form a controlling group with respect to FMR LLC. The address is 245 Summer Street, Boston, MA 02210. This information is based upon the Schedule 13G filed by FMR LLC on February 14, 2017.

(3) Neither FMR LLC nor Abigail P. Johnson has the sole power to vote or direct the voting of the shares owned directly by the various investment companies registered under the Investment Company Act ("Fidelity Funds") advised by Fidelity Management & Research Company ("FMR Co"), a wholly owned subsidiary of FMR LLC, which power resides with the Fidelity Funds' Boards of Trustees. FMR Co carries out the voting of the shares under written guidelines established by the Fidelity Funds' Boards of Trustees.

(4) The board of managers of CRD has voting and dispositive power over these shares. The board of managers of CRD consists of Ward Polzin, Bret Siepman, Chris Carter, David Hayes, Martin Sumner, Christopher Ray and Tony R. Weber. None of such persons individually have voting and dispositive power over these shares, and the board of managers of CRD acts by majority vote and thus each such person is not deemed to beneficially own the shares held by CRD. NGP X US Holdings, L.P. ("NGP X US Holdings") owns approximately 86% of CRD, and certain members of CRD's management team own approximately 14%. As a result, NGP X US Holdings may be deemed to indirectly beneficially own the shares held by CRD. NGP X US Holdings disclaims beneficial ownership of these shares except to the extent of its pecuniary interest therein. NGP X Holdings GP, L.L.C. (the sole general partner of NGP X US Holdings), NGP Natural Resources X, L.P. (the sole member of NGP X Holdings GP, L.L.C.), G.F.W. Energy X, L.P. (the sole general partner of NGP Natural Resources X, L.P.) and GFW X, L.L.C. (the sole general partner of G.F.W. Energy X, L.P.) may each be deemed to share voting and dispositive power over the reported shares and therefore may also be deemed to be the beneficial owner of these shares. GFW X, L.L.C. has delegated full power and authority to manage NGP X US Holdings to NGP Energy Capital Management, L.L.C. and accordingly, NGP Energy Capital Management, L.L.C. may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Chris Carter and Tony R. Weber, both of whom are members of CRD's board of directors, are managing partners of NGP Energy Capital Management, L.L.C. In addition, Craig Glick and Christopher Ray are members of the executive committee of NGP Energy Capital Management, L.L.C. Although none of Messrs. Carter, Weber, Glick or Ray individually have voting or dispositive power over these shares, such individuals may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Each of Messrs. Carter, Weber, Glick and Ray disclaim beneficial ownership of these shares except to the extent of their respective pecuniary interest therein. This information is based upon the Schedule 13D filed jointly by CRD, NGP X US Holdings, L.P., NGP X Holdings GP, L.L.C., NGP Natural Resources X, L.P., G.F.W. Energy X, L.P., GFW X, L.L.C. and NGP Energy Capital Management, L.L.C. on October 21, 2016.

(5) Celero Energy Management, LLC, the general partner of Celero ("Celero GP"), has voting and dispositive power over these shares. The board of managers of Celero GP consists of David Hayes, Bruce Selkirk and Christopher Ray. None of such persons individually have voting and dispositive power over these shares, and the board of managers of Celero GP acts by majority vote and thus each such person is not deemed to beneficially own the shares held by Celero GP. Natural Gas Partners VIII, L.P. ("NGP VIII") owns 94.7% of the membership interests of Celero GP, and the remaining 5.3% is held by certain members of Celero's management team and other minority owners. As a result, NGP VIII may be deemed to indirectly beneficially own these shares. NGP VIII disclaims beneficial ownership of these shares except to the extent of its pecuniary interest therein. G.F.W. Energy VIII, L.P. (the sole general partner of NGP VIII) and GFW VIII, L.L.C. (the sole general partner of G.F.W. Energy VIII, L.P.) may each be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. GFW VIII, L.L.C. has delegated full power and authority to manage NGP VIII to NGP Energy Capital Management, L.L.C. and accordingly, NGP Energy Capital Management, L.L.C. may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Chris Carter and Tony R. Weber (one of our directors) are managing partners of NGP Energy Capital Management, L.L.C. In addition, Craig Glick and Christopher Ray are members of the executive committee of NGP Energy Capital Management, L.L.C. Although none of Messrs. Carter, Weber, Glick or Ray individually have voting or dispositive power over these shares, such individuals may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Each of Messrs. Carter, Weber, Glick and Ray disclaim beneficial ownership of these shares except to the extent of their respective pecuniary interest therein. This information is based upon the Schedule 13D filed jointly by CRD, NGP X US Holdings, L.P., NGP X Holdings GP,

L.L.C., NGP Natural Resources X, L.P., G.F.W. Energy X, L.P., GFW X, L.L.C. and NGP Energy Capital Management, L.L.C. on October 21, 2016.

(6) NGP Centennial Follow-On LLC is managed by its managing member, NGP X US Holdings. As such, NGP X US Holdings has voting and dispositive power over these shares. NGP X US Holdings disclaims beneficial ownership of these shares except to the extent of its pecuniary interest therein. NGP X Holdings GP, L.L.C. (the sole general partner of NGP X US Holdings), NGP Natural Resources X, L.P. (the sole member of NGP X Holdings GP, L.L.C.), G.F.W. Energy X, L.P. (the sole general partner of NGP Natural Resources X, L.P.) and GFW X, L.L.C. (the sole general partner of G.F.W. Energy X, L.P.) may each be deemed to share voting and dispositive power over the reported shares and therefore may also be deemed to be the beneficial owner of these shares. G.F.W. Energy X, L.P. has delegated full power and authority to manage NGP Natural Resources X, L.P. to NGP Energy Capital Management, L.L.C. and accordingly, NGP Energy Capital Management, L.L.C. may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Chris Carter and Tony R. Weber (one of our directors) are managing partners of NGP Energy Capital Management, L.L.C. In addition, Craig Glick and Christopher Ray are members of the executive committee of NGP Energy Capital Management, L.L.C. Although none of Messrs. Carter, Weber, Glick or Ray individually have voting or dispositive power over these shares, such individuals may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Each of Messrs. Carter, Weber, Glick and Ray disclaim beneficial ownership of these shares except to the extent of their respective pecuniary interest therein. This information is based upon the Schedule 13D filed jointly by CRD, NGP X US Holdings, L.P., NGP X Holdings GP, L.L.C., NGP Natural Resources X, L.P., G.F.W. Energy X, L.P., GFW X, L.L.C. and NGP Energy Capital Management, L.L.C. on October 21, 2016.

(7) NGP Centennial Follow-On LLC is managed by its managing member, NGP X US Holdings. As such, NGP X US Holdings has voting and dispositive power over these shares. NGP X US Holdings disclaims beneficial ownership of these shares except to the extent of its pecuniary interest therein. NGP X Holdings GP, L.L.C. (the sole general partner of NGP X US Holdings), NGP Natural Resources X, L.P. (the sole member of NGP X Holdings GP, L.L.C.), G.F.W. Energy X, L.P. (the sole general partner of NGP Natural Resources X, L.P.) and GFW X, L.L.C. (the sole general partner of G.F.W. Energy X, L.P.) may each be deemed to share voting and dispositive power over the reported shares and therefore may also be deemed to be the beneficial owner of these shares. G.F.W. Energy X, L.P. has delegated full power and authority to manage NGP Natural Resources X, L.P. to NGP Energy Capital Management, L.L.C. and accordingly, NGP Energy Capital Management, L.L.C. may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Chris Carter and Tony R. Weber (one of our directors) are managing partners of NGP Energy Capital Management, L.L.C. In addition, Craig Glick and Christopher Ray are members of the executive committee of NGP Energy Capital Management, L.L.C. Although none of Messrs. Carter, Weber, Glick or Ray individually have voting or dispositive power over these shares, such individuals may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares. Each of Messrs. Carter, Weber, Glick and Ray disclaim beneficial ownership of these shares except to the extent of their respective pecuniary interest therein. This information is based upon the Schedule 13D filed jointly by CRD, NGP X US Holdings, L.P., NGP X Holdings GP, L.L.C., NGP Natural Resources X, L.P., G.F.W. Energy X, L.P., GFW X, L.L.C. and NGP Energy Capital Management, L.L.C. on October 21, 2016.

(8) T. Rowe Price Associates, Inc., is a registered investment adviser ("Fund Manager" or "TRPA"). Fund Manager is affiliated with a registered broker-dealer, T. Rowe Price Investment Services, Inc. ("TRPIS"). TRPIS is a subsidiary of the Fund Manager and was formed primarily for the limited purpose of acting as the principal underwriter and distributor of shares of funds in the T. Rowe Price fund family. T. Rowe Price Associates, Inc. serves as investment adviser with power to direct investments and/or sole power to vote the securities owned by the funds and accounts that hold shares of the Company. For purposes of reporting requirements of the Securities Exchange Act of 1934, TRPA may be deemed to be the beneficial owner of all of the shares listed in this table; however, TRPA expressly disclaims that it is, in fact, the beneficial owner of such securities. TRPA is the wholly owned subsidiary of T. Rowe Price Group, Inc., which is a publicly traded financial services holding company. The business address for TRPA is 100 East Pratt Street, Baltimore, Maryland 21202. This information is based upon the Schedule 13G filed by TRPA on February 7, 2017.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information on our equity compensation plans as of December 31, 2016:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options Warrants and Rights	Number of Securities Available for Future Issuance Under Equity Compensation Plans(1)
Equity compensation plans approved by security holders	2,735,500(2)	$14.67	13,482,903
Equity compensation plans not approved by security holders	—	—	—
Total	2,735,500	$14.67	13,482,903

(1) Consists of shares of our Class A Common Stock available for future issuance under our 2016 Long Term Incentive Plan.

(2) Consists of stock options outstanding under our 2016 Long Term Incentive Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Founder Shares

On November 6, 2015, our Sponsor purchased 11,500,000 shares of Class B Common Stock, the founder shares, from us, for an aggregate purchase price of $25,000, or approximately $0.002 per share. In February 2016, our Sponsor transferred 40,000 founder shares to each of our then independent directors (together with our Sponsor, the "initial stockholders") at their original purchase price. On February 24, 2016, we effected a stock dividend of approximately 0.125 shares for each outstanding share of Class B Common Stock, resulting in the initial stockholders holding an aggregate of 12,937,500 founder shares. On April 8, 2016, following the expiration of the underwriters' remaining over-allotment option in connection with our IPO, our Sponsor forfeited 437,500 founder shares, so that the remaining 12,500,000 founder shares held by the initial stockholders would represent 20% of our then issued and outstanding shares of common stock. On October 11, 2016, all of the outstanding founder shares were automatically converted into shares of Class A Common Stock on a one-for-one basis in connection with the closing of the Business Combination.

The initial stockholders have agreed, subject to limited exceptions, not to transfer, assign or sell any of their shares of Class A Common Stock received upon conversion of their founder shares until the earlier to occur of: (A) one year after the closing of the Business Combination or (B) subsequent to the Business Combination, (x) if the last sale price of the Class A Common Stock equals or exceeds $12.00 per share (as adjusted for stock splits, stock dividends, reorganizations, recapitalizations and the like) for any 20 trading days within any 30 trading day period commencing at least 150 days after the closing of the Business Combination, or (y) the date on which we complete a liquidation, merger, stock exchange or other similar transaction that results in all of our stockholders having the right to exchange their shares of common stock for cash, securities or other property.

Administrative Support Agreement

On February 23, 2016, we entered into an administrative support agreement pursuant to which we agreed to pay an affiliate of our Sponsor a total of $10,000 per month for office space, utilities and secretarial and administrative support. We paid the affiliate of our Sponsor $70,000 for such services for the nine months ended September 30, 2016. Following the closing of the Business Combination, we no longer pay these monthly fees.

Private Placement Warrants

On February 29, 2016, our Sponsor purchased from us 8,000,000 Private Placement Warrants at a price of $1.50 per whole warrant ($12.0 million in the aggregate) in a private placement that occurred simultaneously with the closing of our IPO. Each whole Private Placement Warrant is exercisable for one whole share of Class A Common Stock at a price of $11.50 per share. A portion of the purchase price of the Private Placement Warrants was placed in our trust account along with the proceeds from our IPO. The Private Placement Warrants are non-redeemable and exercisable on a cashless basis so long as they are held by our Sponsor or its permitted transferees.

Related Party Loans

On November 6, 2015, our Sponsor agreed to loan us an aggregate of up to $300,000 to cover expenses related to our IPO pursuant to a promissory note (the "2015 Note"). The 2015 Note was non-interest bearing and payable on the earlier of March 31, 2016 or the completion of our IPO. On November 10, 2015, we borrowed $150,000 under the 2015 Note, and we borrowed the remaining $150,000 under the 2015 Note in February 2016. On February 29, 2016, the full $300,000 balance of the 2015 Note was repaid to our Sponsor.

On August 2, 2016, we issued an unsecured, non-interest bearing promissory note to our Sponsor (the "2016 Note"). We borrowed $300,000 under the 2016 Note, and repaid the full $300,000 balance upon the closing of the Business Combination on October 11, 2016.

Agreements Relating to Our Business Combination

Amended and Restated Limited Liability Company Agreement of CRP. In connection with the closing of the Business Combination, on October 11, 2016, we and the Centennial Contributors entered into CRP's fifth amended and restated limited liability company agreement (the "A&R LLC Agreement"). The operations of CRP, and the rights and obligations of the holders of CRP Common Units, are set forth in the A&R LLC Agreement.

Appointment as Manager. Under the A&R LLC Agreement, we are a member and the sole manager of CRP. As the sole manager, we are able to control all of the day-to-day business affairs and decision-making of CRP without the approval of any other member, unless otherwise stated in the A&R LLC Agreement. As such, we, through our officers and directors, are responsible for all operational and administrative decisions of CRP and the day-to-day management of CRP's business. Pursuant to the terms of the A&R LLC Agreement, we cannot, under any circumstances, be removed as the sole manager of CRP except by our election.

Compensation. We are not entitled to compensation for our services as manager. We are entitled to reimbursement by CRP for any reasonable out-of-pocket expenses incurred on behalf of CRP, including all of our fees, expenses and costs of being a public company (including public reporting obligations, proxy statements, stockholder meetings, stock exchange fees, transfer agent fees, SEC and FINRA filing fees and offering expenses) and maintaining our corporate existence.

Recapitalization. The A&R LLC Agreement provided for the exchange of all outstanding membership interests of CRP held by the Centennial Contributors prior to the closing of the Business Combination for newly issued CRP Common Units at the closing. Each CRP Common Unit entitles the holder to a pro rata share of the net profits and net losses and distributions of CRP. As of the closing of the Business Combination, the CRP Common Units represented an approximate 89% ownership interest in CRP.

Distributions. The A&R LLC Agreement allows for distributions to be made by CRP to its members on a pro rata basis out of "distributable cash" (as defined in the A&R LLC Agreement). We expect CRP may make distributions out of distributable cash periodically to the extent permitted by the debt agreements of CRP and necessary to enable us to cover our operating expenses and other obligations, as well as to make dividend payments, if any, to the holders of our Class A Common Stock. In addition, the A&R LLC Agreement generally requires CRP to make pro rata distributions to its members, including us, in an amount at least sufficient to allow us to pay our taxes.

CRP Common Unit Redemption Right. The A&R LLC Agreement provides a redemption right to the Centennial Contributors which entitles them to cause CRP to redeem, from time to time, all or a portion of their CRP Common Units for, at CRP's option, newly-issued shares of our Class A Common Stock on a one-for-one basis or a cash payment equal to the average of the volume-weighted closing price of one share of Class A Common Stock for the five trading days prior to the date the Centennial Contributors deliver a notice of redemption for each CRP Common Unit redeemed (subject to customary adjustments, including for stock splits, stock dividends and reclassifications). In the event of a "reclassification event" (as defined in the A&R LLC Agreement), the manager is to ensure that each CRP Common Unit is redeemable for the same amount and type of property, securities or cash that a share of Class A Common Stock becomes exchangeable for or converted into as a result of such "reclassification event." Upon the exercise of the redemption right, the Centennial Contributor will surrender its CRP Common Units to CRP for cancellation. The A&R LLC Agreement requires that we contribute cash or shares of our Class A Common Stock to CRP in exchange for a number of CRP Common Units in CRP equal to the number of CRP Common Units to be redeemed from the Centennial Contributor. CRP will then distribute such cash or shares of our Class A Common Stock to such Centennial Contributor to complete the redemption. Upon the exercise of the redemption right, we may, at our option, effect a direct exchange of cash or our Class A Common Stock for such CRP Common Units in lieu of such a redemption. Upon the redemption or exchange of CRP Common Units held by a Centennial Contributor, a corresponding number of shares of Class C Common Stock will be canceled.

Change of Control. In connection with the occurrence of a "manager change of control" (as defined below), we have the right to require each member of CRP (other than us) to cause CRP to redeem some or all of such member's CRP Common Units and a corresponding number of shares of Class C Common Stock, in each case, effective immediately prior to the consummation of the manager change of control. From and after the date of such redemption, the CRP Common Units and shares of Class C Common Stock subject to such redemption will be deemed to be transferred to us and each such member will cease to have any rights with respect to the CRP Common Units and shares of Class C Common Stock subject to such redemption (other than the right to receive shares of Class A Common Stock pursuant to such redemption). A "manager change of control" will be deemed to have occurred if or upon: (i) the consummation of a sale, lease or transfer of all or substantially all of our assets (determined on a consolidated basis) to any person or "group" (as such term is used in Section 13(d)(3)) that has been approved by our stockholders and board of directors, (ii) a merger or consolidation of the Company with any other person (other than a transaction in which our voting securities outstanding immediately prior to the transaction continue to represent at least 50.01% of our or the surviving entity's total voting securities following the transaction) that has been approved by our stockholders and board of directors or (iii) subject to certain exceptions, the acquisition by any person or "group" (as such term is used in Section 13(d)(3)) of beneficial ownership of at least 50.01% of our voting securities, if recommended or approved by our board of directors or determined by our board of directors to be in our and our stockholders' best interests.

Maintenance of One-to-One Ratio. The A&R LLC Agreement includes provisions intended to ensure that we at all times maintain a one-to-one ratio between (a) the number of outstanding shares of Class A Common Stock (or other equity securities of the Company) and the number of CRP Common Units (or other corresponding equity securities of CRP) owned by us (subject to certain exceptions for certain rights to purchase our equity securities under a "poison pill" or similar shareholder rights plan, if any, certain convertible or exchangeable securities issued under our equity compensation plans and certain equity securities issued pursuant to our equity compensation plans (other than a stock option plan) that are restricted or have not vested thereunder) and (b) the number of outstanding shares of our Class C Common Stock and the number of CRP Common Units owned by the Centennial Contributors. This construct is intended to result in the Centennial Contributors having a voting interest in the Company that is identical to the Centennial Contributors' economic interest in CRP.

Transfer Restrictions. The A&R LLC Agreement generally does not permit transfers of CRP Common Units by members, subject to limited exceptions. Any transferee of CRP Common Units must assume, by operation of law or written agreement, all of the obligations of a transferring member with respect to the transferred units, even if the transferee is not admitted as a member of CRP.

Dissolution. The A&R LLC Agreement provides that the unanimous consent of all members will be required to voluntarily dissolve CRP. In addition to a voluntary dissolution, CRP will be dissolved upon a change of control transaction under certain circumstances, as well as upon the entry of a decree of judicial dissolution or other circumstances in accordance with Delaware law. Upon a dissolution event, the proceeds of a liquidation will be distributed in the following order: (i) first, to pay the expenses of winding up CRP; (ii) second, to pay debts and liabilities owed to creditors of CRP; and (iii) third, to the members pro-rata in accordance with their respective percentage ownership interests in CRP (as determined based on the number of CRP Common Units held by a member relative to the aggregate number of all outstanding CRP Common Units, in each case treating all units of CRP on an as-converted basis).

Confidentiality. Each member has agreed to maintain the confidentiality of CRP's confidential information. This obligation excludes information independently obtained or developed by the members, information that is in the public domain or otherwise disclosed to a member, in either such case not in violation of a confidentiality obligation or disclosures required by law or judicial process or approved by our chief executive officer.

Indemnification and Exculpation. The A&R LLC Agreement provides for indemnification of the manager, members and officers of CRP and their respective subsidiaries or affiliates and provides that, except as otherwise provided therein, we, as the managing member of CRP, have the same fiduciary duties to CRP and its members as are owed to a corporation organized under Delaware law and its stockholders by its directors.

Amendment to A&R LLC Agreement. On December 28, 2016 and March 20, 2017, in connection with the Silverback Acquisition, the A&R LLC Agreement was amended by Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC and Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC, respectively (the "CRP Amendments"). Pursuant to the CRP Amendments, the Series B Preferred Units were created, with 104,400 of such Series B Preferred Units issued to the Company, in connection with the contribution of proceeds from the Silverback Acquisition Private Placements. Pursuant to the CRP Amendments, the Series B Preferred Units have limited voting rights and are entitled to participate on an as-converted basis with the CRP Common Units in any distributions declared in accordance with the A&R LLC Agreement. The Series B Preferred Units will automatically convert to CRP Common Units upon the conversion of the Company's Series B Preferred Stock.

Amended and Restated Registration Rights Agreement

In connection with the closing of the Business Combination, on October 11, 2016, the Company entered into an amended and restated registration rights agreement (the "Registration Rights Agreement") with our Sponsor, certain of our former and current directors, Riverstone Centennial Holdings, L.P. ("Riverstone Centennial") and the Centennial Contributors, pursuant to which such parties are entitled to certain registration rights relating to (i) shares of our Class A Common Stock issued to our Sponsor and such former and current directors upon the conversion of their founder shares at the closing of the Business Combination, (ii) the Private Placement Warrants and warrants that may be issued upon conversion of working capital loans (and any shares of Class A Common Stock issuable upon the exercise of such warrants), (iii) the shares of Class A Common Stock that have been or may be issued from time to time to certain members of CRP who own CRP Common Units upon the redemption or exchange by such members of CRP Common Units for shares of Class A Common Stock (the "Centennial Holder Shares") and (iv) the shares of Class A Common Stock issued to Riverstone Centennial in the Business Combination Private Placement (collectively, the "Registrable Securities").

The holders of a majority of the Registrable Securities (other than the securities identified in clauses (iii) and (iv) of the preceding paragraph) are entitled to make up to three demands, excluding short form demands, that we register the resale of such securities, while holders of a majority of the Registrable Securities owned by Riverstone Centennial and its permitted transferees are entitled to five demands, excluding short form demands, that we register the resale of such securities. Additionally, the holders of a majority of the Centennial Holder Shares are entitled to demand one underwritten offering if the offering is reasonably expected to result in gross proceeds of more than $50 million. In connection with this Amended and Restated Registration Rights Agreement, we filed a Registration Statement on Form S-1 that was declared effective on November 21, 2016.

The holders also have certain "piggy-back" registration rights with respect to registration statements and rights to require us to register for resale such securities pursuant to Rule 415 under the Securities Act. However, the Registration Rights Agreement provides that we will not permit any registration statement filed under the Securities Act with respect to the founder shares and the Private Placement Warrants and the shares of Class A Common Stock underlying such Private Placement Warrants to become effective until termination of the applicable lock-up period, which occurs (i) in the case of the founder shares, on the earlier of (A) October 11, 2017, (B) if the last sale price of our Class A Common Stock equals or exceeds $12.00 per share (as adjusted for stock splits, stock dividends, reorganizations, recapitalizations and other similar transactions) for any 20 trading days within any 30-trading day period commencing at least 150 days after the Business Combination, or (C) the date on which we complete a liquidation, merger, capital stock exchange, reorganization or other similar transaction that results in all of our stockholders having the right to exchange their shares of common stock for cash, securities or other property and (ii) in the case of the Private Placement Warrants and the shares of Class A Common Stock underlying such Private Placement Warrants, November 11, 2016. We will bear the expenses incurred in connection with the filing of any such registration statements.

Subscription Agreements

In connection with the Business Combination, on July 21, 2016, we entered into subscription agreements with certain investors pursuant to which such investors purchased, in the aggregate, 20,000,000 shares of Class A Common Stock at the closing of the Business Combination for an aggregate purchase price of $200 million. On the same date, the Company entered into a separate subscription agreement with Riverstone Centennial, pursuant to which Riverstone Centennial purchased 81,005,000 shares of Class A Common Stock at the closing of the Business Combination for an aggregate purchase price of approximately $810 million.

In connection with the Silverback Acquisition, on November 27, 2016 (as amended on December 22, 2016), we entered into a subscription agreement with the Riverstone Purchasers, pursuant to which the Riverstone Purchasers agreed to purchase an aggregate of 3,473,590 shares of Class A Common Stock and 104,400 shares of Series B Preferred Stock at the closing for an aggregate purchase price of approximately $430 million. The Series B Preferred Stock are convertible into shares of Class A Common Stock upon the approval of the Company's stockholders of such conversion at a special meeting. In addition, on December 2, 2016, we entered into subscription agreements with the other selling stockholders, pursuant to which such selling stockholders agreed to purchase an aggregate of 33,012,380 shares of Class A Common Stock at the closing for an aggregate purchase price of approximately $480 million. We refer to the subscription agreements entered into by the selling stockholders, including the Riverstone Purchasers, as the "Subscription Agreements."

The shares of Class A Common Stock issued pursuant to the Subscription Agreements and Series B Preferred Stock issued pursuant to the Subscription Agreements were not registered under the Securities Act in reliance upon the exemption provided in Section 4(a)(2) of the Securities Act. The Subscription Agreements provide that the Company must register the resale of the shares of Class A Common Stock issued thereunder pursuant to a registration statement that must be filed within 75 calendar days after consummation of the Silverback Acquisition. The Subscription Agreements provide further that the Company must use its commercially reasonable efforts to have the registration statement declared effective as soon as practicable after the filing thereof, but no later than the earlier of (i) the 90th calendar day following the filing thereof and (ii) the 10th business day after the date the Company is notified (orally or in writing, whichever is earlier) by the SEC that such registration statement will not be "reviewed" or will not be subject to further review.

NGP Affiliated Companies

In May 2016, the Company acquired acreage in close proximity to its operating area in Reeves County, Texas and wellbore only rights in an uncompleted horizontal wellbore for approximately $9.8 million from Caird DB, LLC, an affiliate of NGP.

From time to time, the Company obtains services related to its drilling and completion activities from affiliates of NGP. In particular, the Company has paid the following amounts to the following affiliates of NGP for such services: (i) approximately $0.5 million during the year ended December 31, 2016 to Cretic Energy Services, LLC ("Cretic"); and (ii) approximately $3.3 million during the year ended December 31, 2016 to RockPile Energy Services, LLC. On September 8, 2016, Rockpile Energy Services, LLC, was purchased from NGP by a third party. At December 31, 2016, included in *Accounts payable and accrued expenses* was $0.2 million due to Cretic.

The Company is party to a 15-year gas gathering agreement with PennTex Permian, LLC ("PennTex"), an NGP affiliated company, which terminates on April 1, 2029 and is subject to one-year extensions at either party's election. Under the agreement, PennTex gathers and processes the Company's gas. PennTex purchases the extracted natural gas liquids from the Company, net of gathering fees and an agreed percentage of the actual proceeds from the sale of the residue natural gas and natural gas liquids. Net payments received from PennTex for the periods from October 11, 2016, through December 31, 2016 (Successor) and January 1, 2016, through October 10, 2016 (Predecessor) and the years ended December 31, 2015 and 2014 were $0.2 million, $1.0 million, $1.2 million and $2.2 million, respectively. In the third quarter of 2016, PennTex sold its assets related to this agreement to a third party, and as such, this agreement is no longer with a related party to the Company.

In October 2014, the gas gathering agreement with PennTex was amended to deal with the construction of an expansion of the gathering system and a receipt point.

Riverstone Affiliated Companies

From time to time, the Successor obtains services related to its drilling and completion activities from affiliates of Riverstone.

In particular, the Successor has paid the following amounts to the following affiliates of Riverstone for such services: (i) approximately $8.2 million during the year ended December 31, 2016 to Liberty Oilfield Services, LLC ("Liberty"); and (ii) approximately $1.4 million during the year ended December 31, 2016 to Permian Tank and Manufacturing, Inc. ("Permian"). At December 31, 2016, included in *Accounts payable and accrued expenses* was $3.1 million and $0.4 million due to Liberty and Permian, respectively.

Other Affiliated Companies

Mark G. Papa, our President, Chief Executive Officer and Chairman of the Board, serves as a director and Chairman of the Board of Oil States International, Inc., an energy services company publicly traded on the New York Stock Exchange ("Oil States"). From time to time, the Successor obtains services related to drilling and completion activities from Oil States. In particular, during the fiscal year ended December 31, 2016, the Successor paid approximately $1.2 million to Oil States. At December 31, 2016, included in *Accounts payable and accrued expenses* was $0.2 million due to Oil States.

Related Party Policy

Prior to the closing of our IPO, we did not have a formal policy for the review, approval or ratification of related party transactions. Accordingly, certain of the transactions discussed above were not reviewed, approved or ratified in accordance with any such policy.

We have adopted a code of ethics requiring us to avoid, wherever possible, all conflicts of interests, except under guidelines or resolutions approved by our board of directors (or the appropriate committee of our board) or as disclosed in our public filings with the SEC. Under our code of ethics, conflict of interest situations include any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) involving the company. A copy of our code of ethics is available on our website.

In addition, our Audit Committee, pursuant to its charter, is responsible for reviewing and approving related party transactions to the extent that we enter into such transactions. An affirmative vote of a majority of the members of the Audit Committee present at a meeting at which a quorum is present is required in order to approve a related party transaction. A majority of the members of the entire Audit Committee will constitute a quorum. Without a meeting, the unanimous written consent of all of the members of the Audit Committee will be required to approve a related party transaction. A copy of the Audit Committee charter is available on our website. We also require each of our directors and executive officers to complete a directors' and officers' questionnaire that elicits information about related party transactions.

These procedures are intended to determine whether any such related party transaction impairs the independence of a director or presents a conflict of interest on the part of a director, employee or officer.

Our Audit Committee will review on a quarterly basis any payments that are made to our Sponsor, officers or directors, or our or their affiliates.

Director Independence

NASDAQ listing rules require that a majority of the board of directors of a company listed on NASDAQ be composed of "independent directors," which is defined generally as a person other than an officer or employee of the company or its subsidiaries or any other individual having a relationship which, in the opinion of the company's board of directors would interfere with the director's exercise of independent judgment in carrying out the responsibilities of a director. Prior to December 28, 2016, we were a "controlled company" within the meaning of the NASDAQ listing rules and were able to take advantage of exemptions from certain corporate governance requirements regarding the independence of our board of directors and certain of its committees. Since we are no longer a controlled company, a majority of our board of directors must consist of independent directors within one year of the date we cease to be a controlled company.

Our board of directors has determined that Ms. Maire A. Baldwin and Messrs. Karl E. Bandtel, Jeffrey H. Tepper and Tony R. Weber are independent within the meaning of the NASDAQ listing rules and Rule 10A-3 of the Exchange Act.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

During the fiscal year ended December 31, 2016, WithumSmith+Brown, PC ("Withum") was the Company's principal accountant during the period from January 1, 2016 to November 18, 2016, on which date the audit committee of our board of directors approved a change in accountants and engaged KPMG LLP ("KPMG") as the Company's principal accountant. The following is a summary of fees paid to Withum and KPMG for services rendered:

	Withum	KPMG
2016:		
Audit fees(1)	$ 64,000	$ 500,000
Audit-related fees	83,000	100,000
Tax fees	—	—
All other fees	—	—
Total	$ 147,000	$ 600,000

Audit Committee Approval

Since our audit committee was not formed until our listing on NASDAQ, the audit committee did not pre-approve audit services in connection with our IPO, including the review of our registration statement on Form S-1 and amendments thereto, comfort letters and consents. However, in accordance with Section 10A(i) of the Exchange Act, our audit committee approved, on November 18, 2016, the engagement of Withum to perform the audit services rendered in connection with our quarterly reports on Form 10-Q for the quarters ended March 31, 2016, June 30, 2016 and September 30, 2016 and, on November 18, 2016, the engagement of KPMG to perform the audit services rendered in connection with this annual report.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated.

Exhibit Number	Description of Exhibits
2.1	Contribution Agreement, dated as of July 6, 2016, as amended by Amendment No. 1 thereto, dated as of July 29, 2016, among Centennial Resource Development, LLC, NGP Centennial Follow-On LLC, Celero Energy Company, LP, Centennial Resource Production, LLC and New Centennial, LLC (incorporated by reference to Annex A of the Registrant's definitive proxy statement filed with the SEC on September 23, 2016).
2.2	Purchase and Sale Agreement, dated as of November 21, 2016, by and among SB RS Holdings, LLC, Silverback Exploration, LLC and Silverback Operating, LLC (incorporated by reference to Exhibit 2.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-215621) filed with the SEC on January 19, 2017).
3.1	Second Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
3.2	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 7, 2016).
3.3	Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of October 11, 2016 (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
3.4	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of December 28, 2016 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on December 29, 2016).
3.5*	Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of March 20, 2017.
4.1	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
4.2	Specimen Warrant Certificate (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
4.3	Warrant Agreement between Continental Stock Transfer & Trust Company and the Registrant (incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed with the SEC on February 29, 2016).
4.4	Certificate of Designation of Series A Preferred Stock (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
4.5	Certificate of Designation of Series B Preferred Stock (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on December 29, 2016).
10.1	Amended and Restated Registration Rights Agreement among the Registrant and certain stockholders (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.2	Sponsor Warrants Purchase Agreement, dated February 23, 2016, between the Registrant and Silver Run Sponsor, LLC (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on February 29, 2016).

10.3	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.7 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
10.4	Amended and Restated Credit Agreement, dated as of October 15, 2014, among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-212185) filed with the SEC on June 22, 2016).
10.5	First Amendment to Amended and Restated Credit Agreement, dated as of May 6, 2015, among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and guarantors party thereto (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-212185) filed with the SEC on June 22, 2016).
10.6	Second Amendment to Amended and Restated Credit Agreement, dated as of October 11, 2016, by and among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and guarantors party thereto (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.7	Third Amendment to Amended and Restated Credit Agreement, dated as of December 28, 2016, by and among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and guarantors party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 4, 2017).
10.8	Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed with the Commission on October 11, 2016).
10.9	Form of Stock Option Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed with the Commission on October 11, 2016).
10.10	Form of Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to the Registrant's Current Report on Form 8-K filed with the Commission on October 11, 2016).
10.11	Form of Restricted Stock Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.9 to the Registrant's Current Report on Form 8-K filed with the Commission on October 11, 2016).
21.1	Subsidiaries of the Registrant (incorporated by reference to Exhibit 21.1 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-214355) filed with the SEC on October 31, 2016).
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a).
31.2*	Certification of the Chief Financial Officer required by Rule 13a-14(a) or Rule 15d-14(a).
32.1*	Certification of the Chief Executive Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350.
32.2*	Certification of the Chief Financial Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350.
99.1	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2014 (incorporated by reference to Exhibit 99.1 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-214355) filed with the SEC on October 31, 2016).
99.2	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2015 (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-214355) filed with the SEC on October 31, 2016).
99.3*	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2016.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

George S. Glyphis

Chief Financial Officer, Treasurer and Assistant Secretary

Pursuant to the requirements of the Securities Act of 1934, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ MARK G. PAPA Mark G. Papa	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 23, 2017
/s/ GEORGE S. GLYPHIS George S. Glyphis	Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)	March 23, 2017
/s/ JAMIE L. WHEAT Jamie L. Wheat	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 23, 2017
/s/ MAIRE A. BALDWIN Maire A. Baldwin	Director	March 23, 2017
/s/ KARL E. BANDTEL Karl E. Bandtel	Director	March 23, 2017
/s/ PIERRE F. LAPEYRE, JR. Pierre F. Lapeyre, Jr.	Director	March 23, 2017
/s/ DAVID M. LEUSCHEN David M. Leuschen	Director	March 23, 2017
/s/ JEFFREY H. TEPPER Jeffrey H. Tepper	Director	March 23, 2017
/s/ ROBERT M. TICHIO Robert M. Tichio	Director	March 23, 2017
/s/ TONY R. WEBER Tony R. Weber	Director	March 23, 2017

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DIRECTORS AND OFFICERS

DIRECTORS

Mark G. Papa
President, Chief Executive Officer and Chairman of the Board

Maire A. Baldwin#†

Karl E. Bandtel#!

Robert M. Tichio!
Nominating and Corporate Governance Committee Chairman

Pierre F. Lapeyre, Jr.†
Compensation Committee Chairman

David M. Leuschen†

Jeffrey H. Tepper#†
Audit Committee Chairman

Tony R. Weber†!

EXECUTIVE OFFICERS

Mark G. Papa
President, Chief Executive Officer and Chairman of the Board

George S. Glyphis
Vice President and Chief Financial Officer

Brent P. Jensen
Vice President and Chief Accounting Officer

Sean R. Smith
Vice President and Chief Operating Officer

OTHER OFFICERS

Matt R. Garrison
Vice President of Geosciences

Sean W. Marshall
Vice President of Land

Davis O'Connor
Vice President and General Counsel

Oscar L. Peters
Vice President of Operations

Terry J. Sherban
Vice President, Reservoir Engineering

Audit Committee Member

† Compensation Committee Member

! Nominating & Corporate Governance Committee Member

COMPANY INFORMATION

ANNUAL MEETING

The Annual Meeting will be held at 10:00 am Central Time on June 13, 2017, at the Sugar Land Marriott Town Square located at:

16090 City Walk
Sugar Land, TX 77479

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP

REGISTER AND STOCK TRANSFER AGENT

Continental Stock Transfer & Trust Company

INVESTOR RELATIONS

Hays Mabry
(346) 309-0205
ir@cdevinc.com

COMPANY HEADQUARTERS

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Denver, CO 80202
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info@cdevinc.com
www.cdevinc.com

TICKER

CDEV

STOCK EXCHANGE LISTING

NASDAQ Capital Market

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RESOURCE DEVELOPMENT, INC

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