Filed pursuant to Rule 424(b)(1)
Registration No. 333-228740

PROSPECTUS

61,420,234 Shares

Berry Petroleum Corporation

Common Stock

This prospectus covers the offer and sale of up to 61,420,234 shares of our common stock by the selling stockholders identified in this prospectus, or their permitted transferees.

Pursuant to this prospectus, the selling stockholders, or permitted transferees, may offer and sell the shares of common stock from time to time, as they may determine, through public or private transactions or through other means described in "Plan of Distribution" and at the prices and terms that will be determined by the then-prevailing market prices or at privately negotiated prices, directly or through a broker or brokers, who may act as agent or as principal or by a combination of such methods of sale. For additional information of the methods of sale, you should refer to the section entitled "Plan of Distribution" beginning on page 171. We will not receive any of the proceeds from the sale of the shares by the selling stockholders. We will bear all costs, expenses and fees in connection with the registration of the shares. The selling stockholders will bear all commissions, fees and discounts, if any, attributable to the sale of the shares.

This prospectus describes the general terms of the securities and the general manner in which the selling stockholders will offer the securities. The specific terms of any offering of the securities may be included in a supplement to this prospectus. The prospectus supplement may describe the specific manner in which the selling stockholders will offer the securities and may also add, update or change information contained in this prospectus. You should read this prospectus and any accompanying prospectus supplement carefully before you make your investment decision.

Our common stock is listed on the Nasdaq Global Select Market (the "NASDAQ") under the symbol "BRY." The closing price of our common stock on December 7, 2018 was $12.30 per share.

We are an "emerging growth company" as that term is used in the Jumpstart Our Business Startups Act of 2012 and, as such, are eligible for reduced reporting requirements. Please see "Prospectus Summary—Emerging Growth Company Status."

Investing in our common stock involves risks. Please see "Risk Factors" beginning on page 25 of this prospectus.

Neither the Securities and Exchange Commission ("SEC") nor any state securities commission has approved or disapproved of the securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is December 14, 2018

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Neither we nor the selling stockholders have authorized anyone to provide you with information different from that contained in this prospectus, any prospectus supplement or any free writing prospectus. We take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. The selling stockholders are offering to sell shares of common stock and seeking offers to buy shares of common stock only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the common stock. Our business, financial condition, results of operations and prospects may have changed since that date. This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. Please see "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements."

BASIS OF PRESENTATION

In 2013, Linn Energy, LLC ("Linn Energy") and LinnCo, LLC ("LinnCo" and, together with Linn Energy, the "Linn Entities") acquired Berry Petroleum Company LLC ("Berry LLC" or, prior to February 28, 2017, our "predecessor company"). On May 11, 2016, our predecessor company filed petitions for reorganization in the U.S. Bankruptcy Court (the "Bankruptcy Court") for the Southern District of Texas (collectively, the "Chapter 11 Proceedings") . Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. In anticipation of emergence, Berry Petroleum Corporation ("Berry Corp.") was formed for the purpose of having all the membership interests of Berry LLC assigned to it upon Berry LLC's emergence from bankruptcy. On January 27, 2017, the Bankruptcy Court approved and confirmed the Plan. On February 28, 2017 (the "Effective Date"), the Plan became effective and was implemented, including the emergence of Berry LLC from bankruptcy as a wholly-owned subsidiary of Berry Corp., separate from the Linn Entities. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters.

Upon our emergence, we adopted fresh-start accounting, which, with the recapitalization described above, resulted in Berry Corp. being treated as the new entity for financial reporting. Unless otherwise noted or suggested by context, all financial information and data and accompanying financial statements and corresponding notes, as contained in this prospectus, (i) on or prior to the Effective Date, reflect the actual historical results of operations and financial condition of Berry LLC for the periods presented and do not give effect to the Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry LLC (the "Plan") or any of the transactions contemplated thereby or the adoption of fresh-start accounting, and (ii) following the Effective Date, reflect the actual historical results of operations and financial condition of Berry Corp. on a consolidated basis and give effect to the Plan and any of the transactions contemplated thereby and the adoption of fresh-start accounting. Thus, the financial information presented herein on or prior to the Effective Date is not comparable to information about our performance or financial condition after the Effective Date.

The financial information and certain other information presented in this prospectus have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables in this prospectus. In addition, certain percentages presented in this prospectus reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, or may not sum due to rounding.

INDUSTRY AND MARKET DATA

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications and other published independent sources. Although we believe these third-party sources are reliable as of their respective dates, neither we nor the selling stockholders have independently verified the accuracy or completeness of this information. The industry in which we operate is subject to a high degree of uncertainty and risk due to a variety of factors, including those described in the section entitled "Risk Factors." These and other factors could cause results to differ materially from those expressed in these publications.

TRADEMARKS AND TRADE NAMES

We own or have rights to various trademarks, service marks and trade names that we use in connection with the operation of our business. This prospectus may also contain trademarks, service marks and trade names of third parties, which are the property of their respective owners. Our use or display of third parties' trademarks, service marks, trade names or products in this prospectus is not intended to, and does not imply, a relationship with, or endorsement or sponsorship by us. Solely for convenience, the trademarks, service marks and trade names referred to in this prospectus may appear without the ®, TM or SM symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the rights of the applicable licensor to these trademarks, service marks and trade names.

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the information under the headings "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and the notes to those financial statements appearing elsewhere in this prospectus. You should read "Risk Factors" for information about important risks that you should consider carefully before investing in our common stock.

Except as noted or as the context requires otherwise, when we use the terms "we," "us," "our," the "Company," or similar words in this prospectus, (i) on or prior to the Effective Date, we are referring to Berry LLC, and (ii) following the Effective Date, we are referring to Berry Corp. and its subsidiary, Berry LLC, as applicable. When we refer to "our predecessor company," we are referring to Berry LLC as it existed on or prior to the Effective Date. This prospectus includes certain terms commonly used in the oil and natural gas industry, which are defined elsewhere in this prospectus in "Annex B: Glossary of Oil and Natural Gas Terms."

Our Company

We are a California-based independent upstream energy company engaged primarily in the development and production of conventional oil reserves located onshore in the western United States. Our long-lived, predictable and high margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive free cash flow through commodity price cycles. We believe that executing our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient production growth as well as the ability to return excess free cash flow to stockholders.

We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and the Uinta basin of Utah, and, to a lesser extent, the low geologic risk natural gas resource play in the Piceance basin in Colorado. In the aggregate, the Company's assets are characterized by:

- high oil content, which makes up more than 80% of our production;
- favorable Brent-influenced crude oil pricing dynamics;
- long-lived reserves with low and predictable production decline rates;
- stable and predictable development and production cost structures;
- a large inventory of low-risk identified development drilling opportunities with attractive full-cycle economics; and
- potential in-basin organic and strategic opportunities to expand our existing inventory with new locations of substantially similar geology and economics.

California is and has been one of the most productive oil and natural gas regions in the world. Our asset base is concentrated in the oil-rich San Joaquin basin in California, which has more than 100 years of production history and substantial remaining oil in place. As a result of these attributes, we have a strong understanding of many of the basin's geologic and reservoir characteristics, leading to predictable, repeatable, low-risk development opportunities.

In California, we focus on conventional, shallow reservoirs, the drilling and completion of which are relatively low-cost in contrast to modern unconventional resource plays. Our decades-old proven completion techniques in these reservoirs include steamflood and low-volume fracture stimulation. For example, we estimate the cost for PUD wells drilled and completed in California will average less than $450,000 per well. In contrast, we estimate the cost of PUD wells drilled and completed in the Piceance basin will average $1.8 million per well. Using SEC Pricing as of December 31, 2017, there were approximately 80 gross PUD locations associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.

We own additional assets in the Uinta basin in Utah, a stacked, multi-bench, light-oil-prone play with significant undeveloped resources where we have high operational control and additional behind pipe potential and in the Piceance basin in Colorado, a prolific low geologic risk natural gas play where we produce from a conventional, tight sandstone reservoir using proven slick water fracture stimulation techniques to increase recoveries. On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Using SEC Pricing as of December 31, 2017, we had estimated total proved reserves of 141,384 MBoe. For the three months ended September 30, 2018, we had average production of approximately 27.4 MBoe/d, of which approximately 81% was oil. In California, our average production for the three months ended September 30, 2018 was 19.5 MBoe/d, of which approximately 100% was oil.

The Berry Advantage

We believe that our combination of low production decline rates, high margin oil-weighted production, attractive development opportunities and a stable cost environment differentiates us from our competitors and provides for low-breakeven commodity prices and an ability to generate top-tier corporate level returns, positive Levered Free Cash Flow and capital-efficient growth through commodity price cycles.

Our Low Declining Production Base

Our reserves are generally long-lived and characterized by relatively low production decline rates, affording us significant capital flexibility and an ability to efficiently hedge material quantities of future expected production. For example, our PDP reserves have an estimated annual decline rate of approximately 14% to 12% in the years between 2018 and 2022 based on total PDP Boe reserves as of December 31, 2017 as reflected in our SEC reserve report, which is attached as Annex A. Our SEC reserve report is based on the estimated individual well production profiles used to determine our PDP reserves. Based on the assumptions underlying our PUD estimates, we estimate that we will require approximately $10 per Boe in annual capital expenses to keep production volumes consistent each year over the next three years.

Our Oil-Weighted, High Margin Production

Our highly oil-weighted production combined with a Brent-influenced California pricing dynamic and stable cost structures has resulted, and is expected to continue to result, in strong operating margins. As of December 31, 2017, our California PUD reserves were 100% oil.

Our Attractive Development Opportunities

Our estimated development costs associated with our PUD reserves are $8.89 per Boe on a total company basis and $10.95 per Boe in California. We believe that our estimated development costs, when combined with our operating costs, commodity mix and price realizations, present attractive breakeven economics for our development opportunities.

We expect our identified drilling locations to generate attractive rates of return. The following table presents our expected average single-well rates of return on drilling opportunities associated with our California PUD reserves based on the assumptions used in preparing our December 31, 2017 SEC reserve report, including pricing and cost assumptions, which can be found under “Primary Economic Assumptions” on page 6 of our reserve report. Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude development in the Piceance basin. As a result, information with respect to our Colorado PUDs as of December 31, 2017 has been omitted from the table below. The table also includes a commodity price sensitivity scenario, which is based on Strip Pricing as of May 31, 2018.

Asset	PUD Weighted-Average Economics			
	Per Well		IRR	
	EUR (MBOE)	D&C ($ in thousands)	SEC Pricing as of December 31, 2017(1)	Strip Pricing as of May 31, 2018(2)
California	45	<$450	37%	73%

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl Intercontinental Exchange ("ICE") Brent oil ("Brent") for oil and NGLs and $2.98 per MMBtu New York Mercantile Exchange ("NYMEX") Henry Hub ("HH") for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate, $28.25 per barrel of NGL and $2.935 per thousand cubic feet of gas. The prices were held constant for the lives of the properties, and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules, including adjustment by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Please see "—Summary Reserves and Operating Data."

(2) Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX (HH). The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. Please see "—Summary Reserves and Operating Data."

Our Stable California Operating and Development Cost Environment

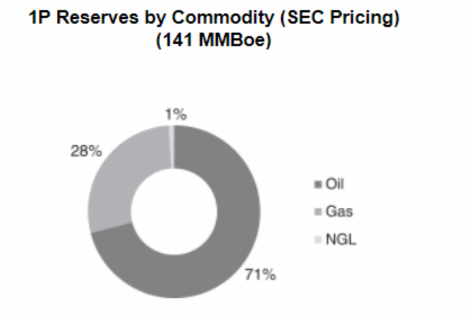
The operating and development cost structures of our conventional California asset base are inherently stable and predictable. Our California focus largely insulates us from the cost inflation pressures experienced by our peers who operate primarily in unconventional plays. This is the result of our established infrastructure, low-intensity service requirements and lack of dependence on inventory-constrained and often highly specialized equipment. In addition, the majority of our California assets reside in the shallow steam-flood fields of the San Joaquin basin, which are lower cost to develop compared to the water flood fields of the Los Angeles and Ventura basins.

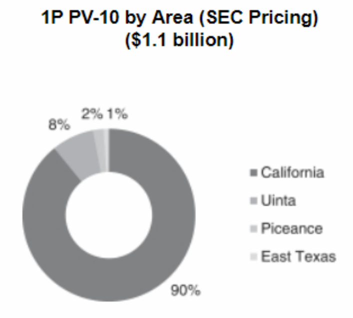
Our Reserves and Assets

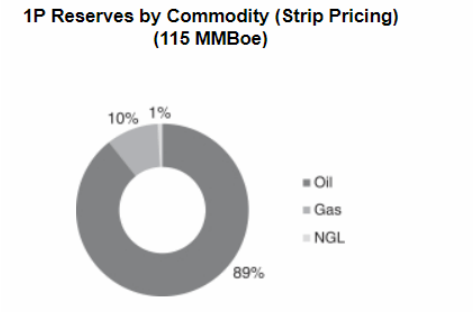
The majority of our reserves are composed of heavy crude oil in shallow, long-lived reservoirs. Approximately two-thirds of our proved reserves and approximately 90% of the PV-10 value of our proved reserves are derived from our assets in California. We also operate in the Uinta basin in Utah, a stacked, multi-bench, light-oil-prone play with significant undeveloped resources and in the Piceance basin in Colorado, a prolific natural gas play with low geologic risk. On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

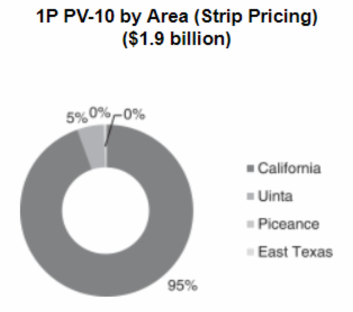
Using SEC Pricing as of December 31, 2017, the standardized measure of discounted future net cash flows of our proved reserves and the PV-10 of our proved reserves were approximately $1.0 billion and $1.1 billion, respectively. Using Strip Pricing as of May 31, 2018, the PV-10 of our proved reserves was approximately $1.9 billion. PV-10 is a financial measure that is not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "—Summary Reserves and Operating Data—PV-10."

The charts below summarize certain characteristics of our proved reserves and PV-10 of proved reserves using SEC Pricing as of December 31, 2017 and Strip Pricing as of May 31, 2018 (as described in the tables below and in "—Summary Reserves and Operating Data"):









The tables below summarize our proved reserves and PV-10 by category using SEC Pricing as of December 31, 2017 and Strip Pricing as of May 31, 2018:

SEC Pricing as of December 31, 2017[1]

	Oil (MMBbl)	Natural Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)	% of Proved	% Proved Developed	Capex[2] ($MM)	PV-10[3] ($MM)
PDP	63	100	1	81	57%	93%	$ 50	$ 762
PDNP	6	—	—	6	4%	7%	10	89
PUD[5]	32	137	—	55	39%	—%	488	262
Total	101	237	1	141	100%	100%	$ 548	$ 1,114

Strip Pricing as of May 31, 2018[4]

	Oil (MMBbl)	Natural Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)	% of Proved	% Proved Developed	Capex[2] ($MM)	PV-10[3] ($MM)
PDP	64	67	1	77	67%	93%	$ 50	$ 1,205
PDNP	6	—	—	6	5%	7%	10	136
PUD	32	—	—	32	28%	—%	348	521
Total	102	67	1	115	100%	100%	$ 407	$ 1,862

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX (HH) for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate, $28.25 per barrel of NGL and $2.935 per thousand cubic feet of gas. The prices

were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules, including adjustment by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Please see "—Summary Reserves and Operating Data."

(2) Represents undiscounted future capital expenditures as of December 31, 2017.

(3) PV-10 is a financial measure that is not calculated in accordance with GAAP. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "—Summary Reserves and Operating Data—PV-10." PV-10 does not give effect to derivatives transactions.

(4) Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX (HH). The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. The decrease in reserve volumes using Strip Pricing as opposed to SEC Pricing is primarily the result of lower realized gas prices in Colorado using Strip Pricing as of May 31, 2018. Please see "—Summary Reserves and Operating Data."

(5) Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude the development in the Piceance basin.

The table below summarizes our average net daily production by basin for the three months ended September 30, 2018:

	Average Net Daily Production[(1)] for the Three Months Ended September 30, 2018	
	(MBoe/d)	**Oil (%)**
California	19.5	100%
Uinta basin	5.1	54%
Piceance basin	2.0	1%
East Texas basin[(2)]	0.7	1%
Total	27.4	81%

(1) Production represents volumes sold during the period.

(2) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Our Development Inventory

We have an extensive inventory of low-risk, high-return development opportunities. As of September 30, 2018, we identified 3,386 gross drilling locations company-wide that we anticipate drilling over the next 5 to 10 years, which we refer to as our "Tier 1" locations, and 3,799 additional gross drilling locations that are currently under review. For a discussion of how we identify drilling locations, please see "Business—Our Reserves and Production Information—Determination of Identified Drilling Locations."

We operate over 95% of our productive wells and expect to operate a similar percentage of our identified gross drilling locations. In addition, approximately 75% of our acreage is held by production, including 99% of our acreage in California. Our high degree of operational control, together with the large portion of our acreage that is held by production, gives us flexibility over the execution of our development program, including the timing, amount and allocation of our capital expenditures, technological enhancements and marketing of production.

The following table summarizes certain information concerning our operations as of September 30, 2018:

	Acreage		Net Acreage Held By Production (%)	Producing Wells, Gross[1] [(2)]	Average Working Interest (%) [(2)(4)]	Net Revenue Interest (%) [(2)(5)]	Identified Drilling Locations[3]	
	Gross	Net					Gross	Net
California	10,926	8,015	99%	2,563	99%	94%	4,991	4,983
Uinta basin	130,677	95,912	72%	935	95%	78%	1,244	1,083
Piceance basin	10,533	8,008	85%	170	72%	63%	870	664
East Texas basin[6]	5,853	4,533	100%	116	99%	74%	80	79
Total	157,989	116,468	75%	3,784	97%	88%	7,185	6,809

(1) Includes 486 steamflood and waterflood injection wells in California.
(2) Excludes 91 wells in the Piceance basin each with a 5% working interest.
(3) Our total identified drilling locations include approximately 790 gross (786 net) locations associated with PUDs as of December 31, 2017, including 161 gross (161 net) steamflood and waterflood injection wells. Please see "Business—Our Reserves and Production Information—Determination of Identified Drilling Locations" for more information regarding the process and criteria through which we identified our drilling locations.
(4) Represents our weighted average working interest in our active wells.
(5) Represents our weighted average net revenue interest for the nine months ended September 30, 2018.
(6) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Additionally, our California assets are primarily focused on the Hill Diatomite, Thermal Diatomite and Thermal Sandstones development areas. As set forth in the table below, as of September 30, 2018, we identified 3,386 Tier 1 gross drilling locations company-wide and 3,799 additional gross drilling locations that are currently under review associated with these assets.

					Gross Drilling Locations[1]		
State	**Project Type**	**Well Type**	**Completion Type**	**Recovery Mechanism**	**Tier 1[2]**	**Additional**	**Total**
California	Hill Diatomite (non-thermal)	Vertical	Low intensity pin point fracture	Pressure depletion augmented with water injection	285	585	870
California	Thermal Diatomite	Vertical	Short interval perforations	Cyclic steam injection	795	979	1,774
California	Thermal Sandstones	Vertical / Horizontal	Perforation/Slotted liner/gravel pack	Continuous and cyclic steam injection	1,855	492	2,347
Utah	Uinta	Vertical / Horizontal	Low intensity fracture stimulation	Pressure depletion	451	793	1,244
Colorado[3]	Piceance	Vertical	Proppantless slick water fracture stimulation	Pressure depletion	—	870	870
Texas[4]	East Texas	Vertical/Horizontal	Low intensity fracture stimulation	Pressure depletion	—	80	80
Total					**3,386**	**3,799**	**7,185**

(1) We had 790 gross (786 net) locations associated with PUDs as of December 31, 2017 using SEC Pricing, including 161 gross (161 net) steamflood and waterflood injection wells. Of those 790 gross PUD locations, 710 are associated with projects in California and 80 are associated with the Piceance basin. Please see "Business—Our Reserves and Production Information—Determination of Identified Drilling Locations" for more information regarding the process and criteria through which we identified our drilling locations. During the nine months ended September 30, 2018, we drilled 86 gross (86 net) wells that were associated with PUDs at December 31, 2017, including 25 gross (25 net) steamflood and waterflood injection wells.
(2) Represents wells that we anticipate drilling over the next 5 to 10 years.
(3) Using SEC Pricing as of December 31, 2017, there were 80 gross PUD locations associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.
(4) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Other Assets

We produce oil from heavy crude reservoirs using steam to heat the oil so that it will flow. To assist in this development, we own and operate five natural gas cogeneration plants that produce steam. These plants supply approximately 23% of our steam needs and approximately 43% of our field electricity needs in California at a discount to electricity market prices. To further offset our costs, we currently also sell surplus power produced by three of our cogeneration facilities under long-term contracts with California utility companies.

In addition, we own gathering, treatment and storage facilities in California that currently have excess capacity, reducing our need to spend capital to develop nearby assets and generally allowing us to control certain operating costs. We also own a network of oil and gas gathering lines across our assets outside of California, and our oil and natural gas is transported through such lines and third-party gathering systems and pipelines.

We also own a natural gas processing plant with capacity of approximately 30 MMcf/d in the Brundage Canyon area, located in Duchesne County, Utah. This facility takes delivery from gathering and compression facilities we operate. Approximately 90% of the gas gathered at these facilities is produced from wells that we operate. Current throughput at the processing plant is 16-18 MMcf/d and sufficient capacity remains for additional large-scale development drilling.

Our Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategy.

- ***Stable, low-decline, predictable and oil-weighted conventional asset base***. The majority of our interests are in properties that have produced for decades. As a result, the geology and reservoir characteristics are well understood, and new development well results are generally predictable, repeatable and present lower risk than unconventional resource plays. The properties are characterized by long-lived reserves with low production decline rates, a stable cost structure and low-risk developmental drilling opportunities with predictable production profiles. The nature of our assets provides us with a high degree of capital flexibility through commodity cycles.

- ***Substantial inventory of low-cost, low-risk and high-return development opportunities***. We expect our locations to generate highly attractive rates of return. For example, our proved undeveloped reserves in California are projected to average single-well rates of return of approximately 37%, assuming SEC Pricing as of December 31, 2017, based on the assumptions used in preparing our SEC reserve report, which can be found under “Primary Economic Assumptions” on page 6 of our reserve report, and 73% assuming Strip Pricing as of May 31, 2018, based on the assumptions found in the Strip Pricing addendum to our reserve report. Our extensive inventory consists of 3,386 Tier 1 gross drilling locations company-wide and 3,799 additional gross drilling locations that are currently under review.

- ***Brent-influenced pricing advantage***. California oil prices are Brent-influenced as California refiners import more than 50% of the state’s demand from foreign sources. There is a closer correlation of prices in California to Brent pricing than to West Texas Intermediate oil ("WTI"). Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, will allow us to continue to realize strong cash margins in California.

- ***Experienced, principled and disciplined management team***. Our management team has significant experience operating and managing oil and gas businesses across numerous domestic and international basins, as well as reservoir and recovery types. We will employ our deep technical, operational and strategic management experience to optimize the value of our assets and the Company. We are focused on the principles of growing Levered Free Cash Flows as well as the value of our production and reserves. In doing so, we take a disciplined approach to development and operating cost management, field development efficiencies and the application of proven technologies and processes new to our properties in order to generate a sustained cost advantage.

- ***Substantial capital flexibility derived from a high degree of operational control and stable cost environment***. We operate over 95% of our productive wells and expect to operate a similar percentage of our identified gross drilling locations. In addition, approximately 75% of our acreage is held by production, including 99% of our acreage in California. Our high degree of operational control over our properties, together with the large portion of our acreage that is held by production, gives us flexibility over the execution of our development program, including the timing, amount and allocation of our capital expenditures, technological enhancements and marketing of production. We expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to fund maintenance operations and growth among other things. Also, unlike our peers who operate primarily in unconventional plays, our assets generally do not necessitate inventory-constrained and highly specialized equipment, which provides us relative insulation from cost inflation pressures. Our high degree of operational control and relatively stable cost environment provide us significant visibility and understanding of our expected cash flows.

- ***Conservative balance sheet leverage with ample liquidity and minimal contractual obligations***. In February 2018, we closed a private offering of $400 million in aggregate principal amount of 7.00% senior unsecured notes due 2026 (the “2026 Notes”), which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers’ discount. As of September 30, 2018, we had $417 million of available liquidity, defined as cash on hand plus availability under the $1.5 billion reserves-based lending facility we entered into on July 31, 2017 (as amended, the “RBL Facility”). In addition, we have minimal long-term service or fixed-volume delivery commitments. This liquidity and flexibility permit us to capitalize on opportunities that may arise to grow and increase stockholder value.

Our Business Strategy

The principal elements of our business strategy include the following:

- ***Grow production and reserves in a capital efficient manner while producing positive internally generated Levered Free Cash Flow***. We intend to allocate capital in a disciplined manner to projects that will produce predictable and attractive rates of return. We plan to direct capital to our oil-rich and low-risk development opportunities while focusing on driving cost efficiencies across our asset base with the primary objective of internally funding our capital budget and growth plan. We may also use our capital flexibility to pursue value-enhancing, bolt-on acquisitions to opportunistically improve our positions in existing basins.

- ***Maximize ultimate hydrocarbon recovery from our assets by optimizing drilling, completion and production techniques and investigating deeper reservoirs and areas beyond our known productive areas***. While we intend to utilize proven techniques and technologies, we will also continuously seek efficiencies in our drilling, completion and production techniques in order to optimize ultimate resource recoveries, rates of return and cash flows. We will explore innovative EOR techniques to unlock additional value and have allocated capital towards next generation technologies. For example, in our South Belridge Hill non-thermal and Midway-Sunset thermal Diatomite properties, we employ both fracture stimulation and advanced thermal techniques, and in our Piceance properties, we use advanced proppantless slick water fracture stimulation techniques. In addition, we intend to take advantage of underdevelopment in basins where we operate by expanding our geologic investigation of deeper reservoirs on our acreage and adjacent acreage below existing producing reservoirs. Through these studies, we will seek to expand our development beyond our known productive areas in order to add probable and possible reserves to our inventory at attractive all-in costs.

- ***Proactively and collaboratively engage in matters related to regulation, safety, environmental and community relations***. We are committed to proactive engagement with regulatory agencies in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with law and regulations. We expect our work with regulators and legislators throughout the rule making process to minimize any adverse impact that new legislation and regulations might have on our ability to maximize our resources. We have found constructive dialogue with regulatory agencies can help avert compliance issues.

- ***Maintain balance sheet strength and flexibility through commodity price cycles***. We intend to fund our capital program while producing positive internally generated Levered Free Cash Flow. Over time, we expect to de-lever through organic growth and with excess Levered Free Cash Flow. Our objective is to achieve and maintain a long-term, through-cycle leverage ratio between 1.5x and 2.0x.

- ***Return excess free cash flow to stockholders***. Our objective is to implement a disciplined and returns-focused approach to capital allocation in order to generate excess free cash flow. We intend to return portions of that excess free cash flow to stockholders on a quarterly basis. If commodity prices increase for a sustained period of time, we would consider repaying debt obligations or returning additional capital to shareholders. For a discussion of our dividend policy, please see “Dividend Policy.”

- ***Enhance future cash flow stability and visibility through an active and continuous hedging program***. Our hedging strategy is designed to insulate our capital program from price fluctuations by securing price realizations and cash flows, including fixed-price gas purchase agreements and other hedging contracts. We have protected a portion of our anticipated production into 2020 as part of our crude oil hedging program. We will review our hedging program continuously as conditions change.

Recent Developments

Initial Public Offering and Series A Preferred Stock Conversion.

In July 2018, we completed the initial public offering of our common stock (the "IPO"), and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY. We received approximately $111 million of net proceeds, after deducting underwriting discounts and offering expenses payable by us, for the 8,695,653 shares of common stock issued for our benefit in the IPO, net of the shares sold for the benefit of certain selling stockholders. The price to the public for the shares sold in our IPO was $14.00 per share.

Of the approximately $111 million of net proceeds we received in the IPO, we used approximately $105 million to repay borrowings under our RBL Facility, which included $60 million we borrowed to make the payment due to the holders of our Series A Preferred Stock in connection with the conversion of preferred stock to common stock. We used the remainder for general corporate purposes.

In connection with the IPO, on July 17, 2018, we entered into stock purchase agreements with certain funds affiliated with Oaktree Capital Management and Benefit Street Partners, pursuant to which we purchased an aggregate of 410,229 and 1,391,967 shares of our common stock, respectively, or 1,802,196 in total. In addition to the 8,695,653 shares of common stock issued and sold for our benefit in the IPO, we simultaneously received $24 million for issuing and selling 1,802,196 shares to the public and paid $24 million to purchase 1,802,196 shares under the stock purchase agreements. We purchased the shares immediately following the closing of the IPO and retired and returned them to the status of authorized but unissued shares.

The selling shareholders sold an additional 2,545,630 shares at a price to the public of $14.00 per share for which we did not receive any proceeds.

In connection with the IPO, each of the 37.7 million shares of our Series A Convertible Preferred Stock, par value $0.001 per share (the “Series A Preferred Stock”), was automatically converted into 1.05 shares of our common stock, or 39.6 million shares in aggregate, and the right to receive a cash payment of $1.75 (the "Series A Preferred Stock Conversion"). The cash payment was reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. The additional 1.9 million shares of common stock (the aggregate conversion premium of 0.05 common share per 1 share of Series A Preferred Stock outstanding) received by the preferred stockholders in the conversion were assigned a value of $14.00 per share in the IPO.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile commodity prices and other material factors. You could lose all or part of your investment. You should bear in mind, in reviewing this prospectus, that past experience is no guarantee of future performance. You should read carefully the section of this prospectus entitled "Risk Factors" beginning on page 25 for an explanation of these risks before investing in our common stock and "Cautionary Note Regarding Forward-Looking Statements" on page 42 of this prospectus. In particular, the following considerations may offset our competitive strengths or have a negative effect on our strategy or operating activities:

- Oil, natural gas and NGL prices are volatile and directly affect our results.
- Our business requires substantial capital investments. We may be unable to fund these investments through operating cash flow or obtain any needed additional capital on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks, including regulatory and permitting risks, that could materially affect its implementation.
- We may be unable to, or may choose not to, enter into sufficient fixed-price purchase or other hedging agreements to fully protect against decreasing spreads between the price of natural gas and oil on an energy equivalent basis or may otherwise be unable to obtain sufficient quantities of natural gas to conduct our steam operations economically or at desired levels.
- We may be unable to hedge anticipated production volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations.
- Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.
- Unless we replace oil and natural gas reserves, our future reserves and production will decline.
- We may not drill our identified sites at the times we scheduled or at all.
- 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 our debt arrangements, which may not be successful.
- We are dependent on our cogeneration facilities to produce steam for our operations. Viable contracts for the sale of surplus electricity, economic market prices and regulatory conditions affect the economic value of these facilities to our operations.
- Future declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in write-downs of the carrying amounts of our assets.
- The inability of one or more of our customers to meet their obligations may have a material adverse effect on our business, financial condition, results of operations and cash flows.
- Due to our limited operating history as an independent company following our emergence from bankruptcy in February 2017, we have been in the process of establishing our accounting and other management systems and resources. We may be unable to effectively develop a mature system of internal controls, and a failure of our control systems to prevent error or fraud may materially harm our company.

The New Berry

Berry was founded by the entrepreneur and our namesake C. J. Berry in the late 1800s. After making his fortune working a small mining operation during the Alaskan gold rush, Mr. Berry returned to California and continued his success with oil exploration and production, founding, in the early 1900s, the business that we would later inherit. Our corporate predecessor company was formed in 1985 after merging several related entities and ultimately became publicly traded beginning in 1987.

In 2013, the Linn Entities acquired our predecessor company. On May 11, 2016 our predecessor company filed bankruptcy. The bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040 (the "Chapter 11 Proceeding"). On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding (the "Plan"). On February 28, 2017, the Effective Date occurred and the Plan became effective and was implemented. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters.

Today, we foster Mr. Berry’s entrepreneurial spirit and leadership skills. We encourage our teams to apply his business ethos at every level to move us forward. We strive to have a positive presence in the communities surrounding our operations. Our employees belong to the communities where they work, which we believe aligns our interests with those of the people who live near our operations.

Emerging Growth Company Status

We are an “emerging growth company” as such term is used in the Jumpstart Our Business Startups Act of 2012 (the “JOBS Act”). For as long as we are an emerging growth company, unlike public companies that are not emerging growth companies, we will not be required to:

- provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002 (“Sarbanes-Oxley Act”);

- provide more than two years of audited financial statements and related management’s discussion and analysis of financial condition and results of operations;

- comply with any new requirements adopted by the Public Company Accounting Oversight Board (the “PCAOB”) requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;

- provide certain disclosure regarding executive compensation required of larger public companies or hold stockholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”); or obtain stockholder approval of any golden parachute payments not previously approved.

We will cease to be an emerging growth company upon the earliest of:

- the last day of the fiscal year in which we have $1.07 billion or more in annual revenues;

- the date on which we become a “large accelerated filer” (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);

- the date on which we issue more than $1.0 billion of non-convertible debt over the prior three-year period; or the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, under Section 107 of the JOBS Act emerging growth companies can also delay adopting new or revised accounting standards until such time as those standards apply to private companies. We intend to take advantage of all of the reduced reporting requirements and exemptions, including the longer phase-in periods for the adoption of new or revised financial accounting standards under Section 107 of the JOBS Act until we are no longer an emerging growth company. Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those of non-emerging growth companies and other emerging growth companies that have opted out of the longer phase-in periods under Section 107 of the JOBS Act and who will comply with new or revised financial accounting standards. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable pursuant to Section 107 of the JOBS Act. For a description of the qualifications and other requirements applicable to emerging growth companies and certain elections that we have made due to our status as an emerging growth company, see “Risk Factors—Risks Related to Our Capital Stock—We are an “emerging growth company,” and will be able take advantage of reduced disclosure requirements applicable to “emerging growth companies,” which could make our common stock less attractive to investors.”

Corporate Information

We were incorporated in Delaware in February 2017. We have executive offices located at 5201 Truxtun Ave., Bakersfield, California 93309 and at 16000 N. Dallas Pkwy, Ste 500, Dallas, Texas 75248, where we have our principal executive offices. Our telephone number is (661) 616-3900, and our web address is *www.berrypetroleum.com*. Information contained in or accessible through our website is not, and should not be deemed to be, part of this prospectus.

THE OFFERING

Common stock that may be offered by the selling stockholders	61,420,234 shares.
Common stock outstanding prior to and after this offering	81,651,098 shares
Use of proceeds	We will not receive any proceeds from the sale of shares of our common stock by the selling stockholders pursuant to this prospectus.
Dividend policy	Please see “Dividend Policy.”
Listing and trading symbol	Our common stock trades on the NASDAQ under the symbol “BRY.”
Risk factors	You should carefully read and consider the information set forth under the heading “Risk Factors” on page 25 of this prospectus and all other information set forth in this prospectus before deciding to invest in our common stock.

SUMMARY HISTORICAL AND PRO FORMA FINANCIAL INFORMATION

The following table shows the summary historical financial information, for the periods and as of the dates indicated, of our predecessor company (Berry LLC) and successor company (Berry Corp.). The summary historical financial information as of and for the year ended December 31, 2016 is derived from the audited historical financial statements of Berry LLC included elsewhere in this prospectus. The summary historical financial information as of and for the two months ended February 28, 2017 is derived from audited financial statements of Berry LLC included elsewhere in this prospectus. The summary historical financial information for the ten months ended December 31, 2017 is derived from audited consolidated financial statements of Berry Corp. included elsewhere in this prospectus. The summary historical financial information as of and for the seven months ended September 30, 2017 and as of and for the nine months ended September 30, 2018 is derived from unaudited consolidated financial statements of Berry Corp. included elsewhere in this prospectus.

Upon Berry LLC's emergence from bankruptcy on February 28, 2017, or the Effective Date, in connection with the Plan, Berry LLC adopted fresh-start accounting and was recapitalized, which resulted in Berry LLC becoming a wholly-owned subsidiary of Berry Corp. and Berry Corp. being treated as the new entity for financial reporting. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. These fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in Berry LLC's historical balance sheet. The effects of the Plan and the application of fresh-start accounting are reflected in Berry Corp.'s consolidated financial statements as of the Effective Date and the related adjustments thereto are recorded in our consolidated statements of operations as reorganization items for the periods prior to the Effective Date. As a result, our consolidated financial statements subsequent to the Effective Date are not comparable to our financial statements prior to such date. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

The summary unaudited pro forma financial information for the year ended December 31, 2017 is derived from the audited historical financial statements of Berry LLC and Berry Corp. included elsewhere in this prospectus. The summary unaudited pro forma financial information for the nine months ended September 30, 2018 is derived from the unaudited historical financial statements of Berry Corp. included elsewhere in this prospectus.

The summary unaudited pro forma financial information for the year ended December 31, 2017 has been prepared to give pro forma effect to (i) the Plan and related transactions and fresh-start accounting, (ii) our sale of an approximately 78% non-operated working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle on July 30, 2017 (the "Hugoton Disposition"), (iii) the 2026 Notes issuance and (iv) the Series A Preferred Stock Conversion and the IPO as if each had been completed as of January 1, 2017. The summary unaudited pro forma financial information does not give effect to the acquisition we made of the remaining approximately 84% non-operated working interest to consolidate with our existing 16% operated working interest in a South Belridge Hill property, located in Kern County, California, in the San Joaquin basin (the "Hill Acquisition") because such transaction is not deemed significant under Rule 3-05 of the SEC's Regulation S-X, so it is not required to be presented.

The summary unaudited pro forma financial information for the nine months ended September 30, 2018 has been prepared to give pro forma effect to (i) the 2026 Notes issuance and (ii) the Series A Preferred Stock Conversion and the IPO as if each had been completed as of January 1, 2017.

The summary unaudited pro forma financial information has been provided for informational and illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Plan, the Hugoton Disposition, the 2026 Notes issuance, the Series A Preferred Stock Conversion or the IPO had been put into effect on the dates indicated, nor are such financial statements necessarily indicative of the financial position or results of operations in future periods.

You should read the following summary information in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical financial statements included elsewhere in this prospectus. Among other things, those historical financial statements include more detailed information regarding the basis of presentation for the following information. The historical financial results are not necessarily indicative of results to be expected for any future period.

	Berry Corp. (Successor)			Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(unaudited)	(audited)	(unaudited)	(audited)	
			($ in thousands)		
Statements of Operations Data:					
Oil, natural gas and NGL sales	$ 410,013	$ 357,928	$ 237,324	$ 74,120	$ 392,345
Electricity sales	25,691	21,972	15,517	3,655	23,204
Gains (losses) on oil derivatives	(131,781)	(66,900)	5,642	12,886	(15,781)
Marketing revenues	1,788	2,694	1,901	633	3,653
Other revenues	500	3,975	3,902	1,424	7,570
Lease operating expenses	137,468	149,599	105,014	28,238	185,056
Electricity generation expenses	13,855	14,894	10,193	3,197	17,133
Transportation expenses	7,640	19,238	18,645	6,194	41,619
Marketing expenses	1,424	2,320	1,674	653	3,100
General and administrative expenses[1]	37,896	56,009	43,529	7,964	79,236
Depreciation, depletion and amortization	62,017	68,478	48,393	28,149	178,223
Impairment of long-lived assets	—	—	—	—	1,030,588
Taxes, other than income taxes	25,288	34,211	25,112	5,212	25,113
(Gains) losses on natural gas derivatives	(1,879)	—	—	—	—
(Gains) losses on sale of assets and other, net	522	(22,930)	(20,687)	(183)	(109)
Interest expense	26,828	18,454	12,482	8,245	61,268
Other (income) expense, net	(135)	(4,071)	(4,071)	63	182
Reorganization items, net (income) expense	(23,192)	1,732	1,001	507,720	72,662
Income tax (benefit) expense	3,145	2,803	9,189	230	116
Net income (loss)	15,334	(21,068)	13,812	(502,964)	(1,283,196)
Conversion and Dividends on Series A Preferred Stock	(97,942)	(18,248)	(12,681)	n/a	n/a
Net income (loss) available to common stockholders	(82,608)	(39,316)	1,131	n/a	n/a
Net income (loss) per share of common stock					
Basic	$ (1.59)	$ (0.98)	$ 0.03	n/a	n/a
Diluted	$ (1.59)	$ (0.98)	$ 0.03	n/a	n/a
Weighted average common stock outstanding					
Basic	51,900	40,000	40,000	n/a	n/a
Diluted[2]	51,900	40,000	40,602	n/a	n/a
Cash Flow Data:					
Net cash provided by (used in)					
Operating activities	$ 7,334	$ 107,399	$ 70,505	$ 22,431	$ 13,197
Capital expenditures	(85,752)	(65,479)	(49,942)	(3,158)	(34,796)
Acquisitions, sales of properties and other investing activities	3,377	(15,046)	(24,621)	25	194
Balance Sheet Data (at period end):					
Total assets	$ 1,539,607	$ 1,546,402	$ 1,579,389	$ 1,561,038	$ 2,652,050
Current portion of long-term debt	—	—	—	—	891,259
Long-term debt, net	391,512	379,000	379,000	400,000	—
Series A Preferred Stock	—	335,000	335,000	335,000	—
Stockholders' and/or member's equity	889,110	859,310	893,241	878,527	502,963
Other Financial Data:					
Adjusted EBITDA[3]	$ 176,256	$ 149,613	$ 96,773	$ 28,845	$ 89,646
Adjusted General and Administrative Expenses[4]	29,133	23,865	15,206	7,964	79,236

(1) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of $8.8 million for the nine months ended September 30, 2018, $32.1 million for the ten months ended December 31, 2017 and $28.3 million for the seven months ended September 30, 2017.

(2) The Series A Preferred Stock was not a participating security; therefore, we calculated diluted earnings per share using the "if-converted" method, under which the preferred dividends are added back to the numerator and the Series A Preferred Stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock were included in the diluted earnings per share calculation for the nine months ended September 30, 2018 and the ten months ended December 2017, as their effect was antidilutive under the "if-converted" method. In July 2018, all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO. Please see "—Recent Developments—Initial Public Offering and Series A Preferred Stock Conversion."

(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

(4) Adjusted General and Administrative Expenses is a non-GAAP financial measure. For a definition of Adjusted General and Administrative Expenses and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

	Pro Forma	
	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
	($ in thousands)	
Statements of Operations Data:		
Oil, natural gas and NGL sales	$ 410,013	$ 394,206
Gain (losses) on oil derivatives	(131,781)	(54,014)
Lease operating expenses	137,468	171,708
Transportation expenses	7,640	15,425
General and administrative expenses[1]	37,896	62,681
Depreciation, depletion and amortization	62,017	75,837
Taxes, other than income taxes	25,288	34,555
Interest expense	(26,828)	(31,110)
Reorganization items, net (income) expense	23,192	(1,732)
Income tax (benefit) expense	3,124	1,800
Net income (loss)	15,233	(42,441)

(1) Includes non-recurring restructuring and other costs and non-cash stock compensation expense of $8.8 million for the nine months ended September 30, 2018 and $32.1 million for the year ended December 31, 2017.

Non-GAAP Financial Measures

Adjusted EBITDA, Levered Free Cash Flow and Adjusted Net Income (Loss)

Adjusted EBITDA and Adjusted Net Income (Loss) are not measures of net income (loss) and Levered Free Cash Flow is not a measure of cash flow, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow are supplemental non-GAAP financial measures used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

Adjusted Net Income (Loss) excludes the impact of unusual, out-of-period and infrequent items affecting earnings that vary widely and unpredictably, including non-cash items such as derivative gains and losses. This measure is used by management when comparing results period over period. We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate.

We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, amortization and accretion; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

Our management believes Adjusted EBITDA provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and the investment community. The measure also allows our management to more effectively evaluate our operating performance and compare the results between periods without regard to our financing methods or capital structure. Levered Free Cash Flow is used by management as a primary metric to plan capital allocation for maintenance and internal growth opportunities, as well as hedging needs. It also serves as a measure for assessing our financial performance and our ability to generate excess cash from operations to service debt and pay dividends.

While Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Our computations of Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

Adjusted General and Administrative Expenses

Adjusted General and Administrative Expenses is a supplemental non-GAAP financial measure that is used by management. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period.

We exclude the items listed above from general and administrative expenses in arriving at Adjusted General and Administrative Expenses because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature. Adjusted General and Administrative Expenses should not be considered as an alternative to, or more meaningful than, general and administrative expenses as determined in accordance with GAAP. Our computations of Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures of other companies.

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The following tables present reconciliations of the non-GAAP financial measures Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow to the GAAP financial measures of net income (loss) and net cash provided or used by operating activities, as applicable, for each of the periods indicated.

	Berry Corp. (Successor)						Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	($ in thousands)							
Adjusted EBITDA reconciliation to net income (loss):								
Net income (loss)	$ 36,985	$ (28,061)	$ (9,684)	$ 15,334	$ (21,068)	$ 13,812	$ (502,964)	$ (1,283,196)
Add (Subtract):								
Depreciation, depletion, amortization and accretion	21,729	21,859	20,822	62,017	68,478	48,392	28,149	178,223
Interest expense	9,877	9,155	5,882	26,828	18,454	12,482	8,245	61,268
Income tax (benefit) expense	7,683	(5,476)	(6,246)	3,145	2,803	9,190	230	116
Derivative (gain) loss	17,115	78,143	42,443	129,902	66,900	(5,642)	(12,886)	20,386
Net cash received (paid) for scheduled derivative settlements	(1,052)	(28,261)	4,045	(47,161)	3,068	9,902	534	9,708
(Gain) loss on sale of assets and other	400	123	(20,692)	522	(22,930)	(20,687)	(183)	(109)
Impairments	—	—	—	—	—	—	—	1,030,588
Stock compensation expense	1,182	1,278	902	3,502	1,851	902	—	—
Non-recurring restructuring and other costs	1,598	1,714	2,979	5,359	30,325	27,421	—	—
Reorganization items, net	(13,781)	(456)	408	(23,192)	1,732	1,001	507,720	72,662
Adjusted EBITDA[(1)]	$ 81,736	$ 50,018	$ 40,859	$ 176,256	$ 149,613	$ 96,773	$ 28,845	$ 89,646

(1) Adjusted EBITDA includes cash paid for scheduled derivative settlements of $1 million for the three months ended September 30, 2018, $28 million for the three months ended June 30, 2018, and $47 million for the nine months ended September 30, 2018; and includes cash received for scheduled derivative settlements of $4 million for the three months ended September 30, 2017, $3 million for the ten months ended December 31, 2017, $10 million for the seven months ended September 30, 2017, $1 million for the two months ended February 28, 2017, and $10 million for the year ended December 31, 2016.

	Berry Corp. (Successor)						Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	($ in thousands)							
Adjusted EBITDA and Levered Free Cash Flow reconciliation to net cash provided (used) by operating activities:								
Net cash provided by (used in) operating activities	$ 56,880	$ (77,394)	$ 25,568	$ 7,334	$ 107,399	$ 70,505	$ 22,431	$ 13,197
Add (Subtract):								
Cash interest payments	15,902	644	4,726	19,199	14,276	9,987	8,057	57,759
Cash income tax payments	—	—	826	—	1,994	1,994	—	347
Cash reorganization item (receipts) payments	(345)	1,047	417	1,007	1,732	(375)	11,838	19,116
Non-recurring restructuring and other costs	1,598	1,714	2,979	5,359	30,325	27,421	—	—
Derivative early termination payment	—	126,949	—	126,949	—	—	—	—
Other changes in operating assets and liabilities	7,701	(2,942)	6,343	16,408	(6,113)	(12,759)	(13,323)	(876)
Other, net	—	—	—	—	—	—	(158)	103
Adjusted EBITDA	81,736	50,018	40,859	176,256	149,613	96,773	28,845	89,646
Subtract:								
Capital expenditures - accrual basis	(40,243)	(38,531)	(16,902)	(94,505)	(65,479)	(50,953)	(5,406)	(34,796)
Interest expense	(9,877)	(9,155)	(5,882)	(26,828)	(18,454)	(12,482)	(8,245)	(61,268)
Cash dividends declared	(7,431)	(5,651)	—	(18,732)	(18,248)	—	—	—
Levered Free Cash Flow[(1)]	$ 24,185	$ (3,319)	$ 18,075	$ 36,191	$ 47,432	$ 33,338	$ 15,194	$ (6,418)

(1) Levered Free Cash Flow includes cash paid for scheduled derivative settlements of $1 million for the three months ended September 30, 2018, $28 million for the three months ended June 30, 2018, and $47 million for the nine months ended September 30, 2018; and includes cash received for scheduled derivative settlements of $4 million for the three months ended September 30, 2017, $3 million for the ten months ended December 31, 2017, $10 million for the seven months ended September 30, 2017, $1 million for the two months ended February 28, 2017, and $10 million for the year ended December 31, 2016.

The following table presents a reconciliation of the non-GAAP financial measure Adjusted Net Income (Loss) to the GAAP financial measure of Net income (loss).

	Berry Corp. (Successor)						Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	($ in thousands)							
Adjusted Net Income (Loss) reconciliation to Net income (loss)								
Net income (loss)	$ 36,985	$ (28,061)	$ (9,684)	$ 15,334	$ (21,068)	$ 13,812	$ (502,964)	$ (1,283,196)
Add (Subtract):								
(Gains) losses on oil and natural gas derivatives	17,115	78,143	42,443	129,902	66,900	(5,642)	(12,886)	20,386
Net cash received (paid) for scheduled derivative settlements	(1,052)	(28,261)	4,045	(47,161)	3,068	9,902	534	9,708
(Gains) losses on sale of assets and other, net	400	123	(20,692)	522	(22,930)	(20,687)	(183)	(109)
Impairments	—	—	—	—	—	—	—	1,030,588
Non-recurring restructuring and other costs	1,598	1,714	2,979	5,359	30,325	27,421	—	—
Reorganization items, net	(13,781)	(456)	408	(23,192)	1,732	1,001	507,720	72,662
Total additions, net	4,280	51,263	29,183	65,430	79,095	11,995	495,185	1,133,235
Income tax benefit (expense) of adjustments at effective tax rate	(736)	(8,371)	(11,673)	(11,137)	(22,147)	(4,798)	—	—
Adjusted Net Income (Loss)	$ 40,529	$ 14,831	$ 7,826	$ 69,627	$ 35,880	$ 21,009	$ (7,779)	$ (149,961)

(1) For the ten months ended December 31, 2017, our effective tax rate was (15%) due to a net loss and valuation allowances. For purposes of this calculation, we used the statutory rate for this period, which was 28%.

The following table presents a reconciliation of the non-GAAP financial measure Adjusted General and Administrative Expenses to the GAAP financial measure of general and administrative expenses for each of the periods indicated.

	Berry Corp. (Successor)						Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	($ in thousands)							
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:								
General and administrative expenses	$ 13,429	$ 12,482	$ 11,729	$ 37,896	$ 56,009	$ 43,529	$ 7,964	$ 79,236
Subtract:								
Non-recurring restructuring and other costs	(1,598)	(1,714)	(2,979)	(5,359)	(30,325)	(27,421)	—	—
Non-cash stock compensation expense	(1,125)	(1,260)	(902)	(3,404)	(1,819)	(902)	—	—
Adjusted General and Administrative Expenses	$ 10,706	$ 9,508	$ 7,848	$ 29,133	$ 23,865	$ 15,206	$ 7,964	$ 79,236

Summary Reserves and Operating Data

The following tables present summary data with respect to our estimated proved oil, natural gas and NGL reserves and operating data as of the dates presented. In evaluating the material presented below, please see "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business—Our Reserves and Production Information" and our financial statements and notes thereto. Our historical results of operations are not necessarily indicative of results to be expected for any future period.

Reserves

The following table summarizes our estimated proved reserves and related PV-10 using SEC Pricing as of December 31, 2017 and Strip Pricing as of May 31, 2018. The reserve estimates presented in the table below are based on reports prepared by DeGolyer and MacNaughton. The SEC Pricing reserve estimates were prepared in accordance with current SEC rules and regulations regarding oil, natural gas and NGL reserve reporting and Strip Pricing data was prepared using closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018. Reserves are stated net of applicable royalties.

	SEC Pricing as of December 31, 2017[1]					Strip Pricing as of May 31, 2018[2]				
	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin[3]	Total	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin[3]	Total
Proved developed reserves:										
Oil (MMBbl)	61	7	—	—	68	63	7	—	—	70
Natural Gas (Bcf)	—	47	42	12	100	—	41	17	9	67
NGLs (MMBbl)	—	1	—	—	1	—	1	—	—	1
Total (MMBoe)[4][5]	61	16	7	2	86	63	15	3	2	82
Proved undeveloped reserves[7]:										
Oil (MMBbl)	32	—	—	—	32	32	—	—	—	32
Natural Gas (Bcf)	—	—	137	—	137	—	—	—	—	—
NGLs (MMBbl)	—	—	—	—	—	—	—	—	—	—
Total (MMBoe)[5]	32	—	23	—	55	32	—	—	—	32
Total proved reserves:										
Oil (MMBbl)	93	7	—	—	101	95	7	—	—	102
Natural Gas (Bcf)	—	47	179	12	237	—	41	17	9	67
NGLs (MMBbl)	—	1	—	—	1	—	1	—	—	1
Total (MMBoe)[5]	93	16	30	2	141	95	15	3	2	115
PV-10 ($MM)[6]	998	84	24	7	1,114	1,762	91	4	5	1,862

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX (HH) for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate, $28.25 per barrel of NGL and $2.935 per thousand cubic feet of gas. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules including adjustments by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. For more information regarding commodity price risk, please see "Risk Factors—Risks Related to Our Business and Industry—Oil, natural gas and NGL prices are volatile and directly affect our results."

(2) Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance.

Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX (HH). The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00.

We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves.

The decrease in reserve volumes using Strip Pricing as opposed to SEC Pricing is primarily the result of lower realized gas prices in Colorado using Strip Pricing as of May 31, 2018.

(3) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

(4) Approximately 9% of proved developed oil reserves, 1% of proved developed NGLs reserves, 0% of proved developed natural gas reserves and 7% of total proved developed reserves are non-producing.

(5) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

(6) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "—PV-10." PV-10 does not give effect to derivatives transactions.

(7) Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.

PV-10

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Management believes that PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the Company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

The following table provides a reconciliation of PV-10 of our proved reserves to the standardized measure of discounted future net cash flows using SEC Pricing at December 31, 2017:

	At December 31, 2017 ($ in millions)
PV-10	$ 1,114
Less: present value of future income taxes discounted at 10%	(137)
Standardized measure of discounted future net cash flows	$ 977

GAAP does not prescribe any corresponding measure for PV-10 of reserves as of an interim date or on any basis other than SEC prices. As a result, it is not practicable for us to reconcile PV-10 using Strip Pricing as of May 31, 2018 to GAAP standardized measure.

Production and Operating Data

The following table sets forth information regarding production, realized and benchmark prices, and production costs (i) on a historical basis for the year ended December 31, 2016, the two months ended February 28, 2017, the seven months ended September 30, 2017, the ten months ended December 31, 2017 and the nine months ended September 30, 2018 and (ii) on a pro forma basis for the year ended December 31, 2017.

The pro forma information has been prepared to give pro forma effect to (i) the Plan and related transactions and fresh-start accounting and (ii) the Hugoton Disposition, as if each had been completed as of January 1, 2017, respectively.

The summary unaudited pro forma financial information does not give effect to the Hill Acquisition because such transaction is not deemed significant under Rule 3-05 of the SEC's Regulation S-X, so it is not required to be presented herein. For more information, see "—Summary Historical and Pro Forma Financial Information."

For additional information regarding pricing dynamics, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Business Environment and Market Conditions."

	Pro Forma[4]	Berry Corp.(Successor)			Berry LLC (Predecessor)	
	Year Ended December 31, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Production Data[5]:						
Oil (MBbl/d)	20.5	21.5	20.6	20.0	19.5	23.1
Natural gas (MMcf/d)	31.2	27.7	49.4	57.2	71.7	78.1
NGLs (MBbl/d)	0.6	0.6	2.0	2.6	5.2	3.6
Average daily combined production (MBoe/d)[1]	26.3	26.7	30.9	32.1	36.7	39.7
Oil (MBbl)	7,471	5,867	6,318	4,288	1,153	8,463
Natural gas (MMcf)	11,382	7,555	15,119	12,241	4,232	28,577
NGLs (MBbl)	216	157	605	552	304	1,307
Total combined production (MBoe)[1]	9,584	7,284	9,443	6,880	2,162	14,533
Weighted average realized prices:						
Oil with hedges (per Bbl)	$ 48.37	$ 57.96	$ 48.53	$ 47.17	$ 47.40	$ 36.88
Oil without hedges (per Bbl)	$ 47.89	$ 65.97	$ 48.05	$ 44.87	$ 46.94	$ 35.83
Natural gas (per Mcf)	$ 2.82	$ 2.44	$ 2.70	$ 2.69	$ 3.42	$ 2.31
NGLs (per Bbl)	$ 20.00	$ 28.93	$ 22.23	$ 21.67	$ 18.20	$ 17.67
Average Benchmark prices:						
Oil (Bbl) – Brent	$ 54.82	$ 72.67	$ 54.65	$ 51.70	$ 55.72	$ 45.00
Oil (Bbl) – WTI	$ 50.95	$ 66.75	$ 50.53	$ 48.45	$ 53.04	$ 43.32
Natural gas (MMBtu) – HH	$ 3.11	$ 2.90	$ 3.00	$ 3.03	$ 3.66	$ 2.46
Average costs per Boe[2]:						
Lease operating expenses	$ 17.92	$ 18.87	$ 15.84	$ 15.26	$ 13.06	$ 12.73
Electricity generation expenses	1.89	1.90	1.58	1.48	1.48	1.18
Electricity sales	(2.67)	(3.53)	(2.33)	(2.26)	(1.69)	(1.60)
Transportation expenses	1.61	1.05	2.04	2.71	2.86	2.86
Transportation sales[2]	—	(0.07)	—	—	—	—
Marketing expenses	0.31	0.20	0.25	0.24	0.30	0.21
Marketing revenues	(0.35)	(0.25)	(0.29)	(0.28)	(0.29)	(0.25)
Total operating expenses	$ 18.71	$ 18.17	$ 17.09	$ 17.15	$ 15.72	$ 15.13
General and Administrative Expenses[3]	$ 6.54	$ 5.20	$ 5.93	$ 6.33	$ 3.68	$ 5.45
Depreciation, depletion and amortization	$ 7.91	$ 8.51	$ 7.25	$ 7.03	$ 13.02	$ 12.26
Taxes, other than income taxes	$ 3.61	$ 3.47	$ 3.62	$ 3.65	$ 2.41	$ 1.73

(1) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

(2) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to-date.

(3) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of approximately $2.77, $3.40, $1.22, $4.12 and none per Boe for the pro forma year ended December 31, 2017, the ten months ended December 31, 2017, the nine months ended September 30, 2018, the seven months ended September 30, 2017 and the two months ended February 28, 2017, respectively.

(4) Does not include the effects of the Hill Acquisition. We estimate that the additional production associated with the Hill Acquisition for the year ended December 31, 2017 was approximately 637,000 Boe or 1,745 Boe/d.

(5) Production represents volumes sold during the period.

RISK FACTORS

An investment in our common stock involves a number of risks. You should carefully consider each of the following risk factors and all of the other information set forth in this prospectus before making an investment decision. If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. If any of these risks occur, the trading price of our common stock could decline and you may lose all or part of your investment.

Risks Related to Our Business and Industry

The risks and uncertainties described below are among the items we have identified that could materially adversely affect our business, production, growth plans, reserves quantities or value, operating or capital costs, financial condition, and results of operations and our ability to meet our capital expenditure plans and other obligations and financial commitments.

Oil, natural gas and NGL prices are volatile and directly affect our results.

The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital, future rate of growth and the carrying value of our properties. Prices for these commodities have, and may continue to, fluctuate widely in response to market uncertainty and to relatively minor changes in the supply of and demand for oil, natural gas and NGLs. For example, the Brent crude oil future contract price declined from a high of over $108.19 per Bbl in July 2014 to a low of $31.93 per Bbl in January 2016. The HH spot price for natural gas has also declined since 2014. While oil prices remain lower than the 2014 averages, they have improved since early 2016. However, such improvements may not continue or may be reversed. 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, and transportation costs of, oil and natural gas;
- the price and quantity of foreign imports of oil;
- prevailing prices on local price indexes in the areas in which we operate;
- political and economic conditions in, or affecting, other producing regions or countries, including the Middle East, Africa, South America and Russia;
- the level of global exploration, development and production, and resulting inventories;
- 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;
- actions of other significant producers;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and natural disasters;
- technological advances, conservation efforts and availability of alternative fuels affecting oil and gas consumption;
- refining and processing disruptions or bottlenecks;
- the impact of the U.S. dollar exchange rates on oil;
- expectations about future oil and gas prices; and

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

Lower oil prices may reduce our cash flow 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, lower prices generally adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. In addition, a portion of our PUDs may no longer meet the economic producibility criteria under the applicable rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit.

In addition, sustained periods with oil and natural gas prices at levels lower than current prices also may adversely affect our drilling economics, which may require us to postpone or eliminate all or part of our development program, and result in the reduction of some of our proved undeveloped reserves, which would reduce the net present value of our reserves.

Our business requires substantial capital investments. We may be unable to fund these investments through operating cash flow or obtain any needed additional capital on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks, including regulatory and permitting risks, that could materially affect its implementation.

Our industry is capital intensive. We make and expect to continue to make substantial capital investments for the development and exploration of our oil and natural gas reserves. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of permits and regulatory, technological and competitive developments. A reduction or sustained decline in commodity prices from current levels may force us to reduce our capital expenditures, which would negatively impact our ability to grow production. We have a 2018 capital expenditure budget of approximately $140 million to $160 million. We expect to fund our capital expenditures with cash flows from our operations; however, our cash flows from operations, and access to capital should such cash flows prove inadequate, are subject to a number of variables, including:

- the volume of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold and our operating expenses;
- the extent and levels of our derivatives activities;
- our proved reserves, including our ability to acquire, locate and produce new reserves;
- our ability to borrow under the RBL Facility;
- and our ability to access the capital markets.

If our revenues or the borrowing base under the RBL 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 and growth at current levels. If additional capital were needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If we are able to obtain debt financing, it would require that a portion of our cash flows from operations be used to service such indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions. If cash flows generated by our operations or available borrowings under the RBL Facility were 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, which in turn could lead to a decline in our reserves and production. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

We may be unable to, or may choose not to, enter into sufficient fixed-price purchase or other hedging agreements to fully protect against decreasing spreads between the price of natural gas and oil on an energy equivalent basis or may otherwise be unable to obtain sufficient quantities of natural gas to conduct our steam operations economically or at desired levels.

The development of our heavy oil in California is subject to our ability to generate sufficient quantities of steam using natural gas at an economically effective cost. As a result, we need access to natural gas at prices sufficiently lower than oil prices on an energy equivalent basis to economically produce our heavy oil. We seek to reduce our exposure to the potential unavailability of natural gas and to pricing by entering into fixed-price purchase agreements and other hedging transactions. We may be unable to, or may choose not to, enter into sufficient such agreements to fully protect against decreasing spreads between the price of natural gas and oil on an energy equivalent basis or may otherwise be unable to obtain sufficient quantities of natural gas to conduct our steam operations economically or at desired levels. Our hedges are based on major oil and gas indexes, which may not fully reflect the prices we realize locally. Consequently, the price protection we receive may not fully offset local price declines.

We may be unable to hedge anticipated production volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations, and our commodity-price risk-management activities may prevent us from fully benefiting from price increases and may expose us to other risks.

As of September 30, 2018, we have hedged crude oil production at the following approximate volumes and prices: 12.8 MBbl/d at $75 per barrel in the fourth quarter of 2018, 16.5 MBbl/d at $70 per barrel in 2019, and 1.2 MBbl/d at $65 per barrel in 2020. In the future, we may be unable to hedge anticipated production volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations.

Our current commodity-price risk-management activities may prevent us from realizing the full benefits of price increases above the levels determined under the derivative instruments we use to manage price risk. In addition, our commodity-price risk-management activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements; and
- an event materially impacts oil and natural gas prices in the opposite direction of our derivative positions.

Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including well stimulation, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to environmental protection and the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

See “Business—Regulation of Health, Safety and Environmental Matters” for a description of laws and regulations that affect our business. To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, fluid injection and disposal, stimulation, operation, maintenance, transportation, marketing, site remediation, decommissioning, abandonment and water recycling and reuse. These permits are generally subject to protest, appeal or litigation, which could in certain cases delay or halt projects, production of wells and other operations. Additionally, failure to comply may result in the assessment of administrative, civil and criminal fines and penalties and liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or limiting our operations.

Our operations may also be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Such 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. Permanent restrictions imposed to protect threatened or endangered species or their habitat could prohibit drilling in certain areas or require the implementation of expensive mitigation measures.

Our customers, including refineries and utilities, and the businesses that transport our products to customers are also highly regulated. For example, federal and state pipeline safety agencies have adopted or proposed regulations to expand their jurisdiction to include more gas and liquid gathering lines and pipelines and to impose additional mechanical integrity requirements. The State of California has adopted additional regulations on the storage of natural gas that could affect the demand or availability of such storage, increase seasonal volatility, or otherwise affect the prices we pay for fuel gas.

Costs of compliance may increase, and operational delays or restrictions may occur as existing laws and regulations are revised or reinterpreted, or as new laws and regulations become applicable to our operations, each of which has occurred in the past. For example, our costs have recently begun to increase due to increased fluid injection regulation and idle well decommissioning.

Government authorities and other organizations continue to study health, safety and environmental aspects of oil and natural gas operations, including those related to air, soil and water quality, ground movement or seismicity and natural resources. Government authorities have also adopted or proposed new or more stringent requirements for permitting, well construction and public disclosure or environmental review of, or restrictions on, oil and natural gas operations. Such requirements or associated litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, fluid injection and disposal or production activities, and preclude us from drilling, completing or stimulating wells, which could have an adverse effect on our expected production, other operations and financial condition.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Estimation of reserves and related future net cash flows is a partially subjective process of estimating accumulations of oil and natural gas that includes many uncertainties. Our estimates are based on various assumptions, which may ultimately prove to be inaccurate, including:

- the similarity of reservoir performance in other areas to expected performance from our assets;
- the quality, quantity and interpretation of available relevant data;
- commodity prices (see “—Oil, natural gas and NGL prices are volatile and directly affect our results.”);
- production and operating costs;
- ad valorem, excise and income taxes;
- development costs;
- the effects of government regulations; and future workover and asset retirement costs.

Misunderstanding these variables, inaccurate assumptions, changed circumstances or new information could require us to make significant negative reserves revisions.

We currently expect improved recovery, extensions and discoveries and, potentially acquisitions, to be our main sources for reserves additions. However, factors such as the availability of capital, geology, government regulations and permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions. Any material inaccuracies in our reserves estimates could materially affect the net present value of our reserves, which could adversely affect our borrowing base and liquidity under the RBL Facility, as well as our results of operations.

Unless we replace oil and natural gas reserves, our future reserves and production will decline.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Reduced capital investment may result in a decline in our reserves. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent cash flow from operations or external sources of capital are insufficient. We may not be successful in developing, exploring for or acquiring additional reserves. Over the long-term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

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, production and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable or economically desirable oil and natural gas production or may result in a downward revision of our estimated proved reserves due to:

- poor production response;
- ineffective application of recovery techniques;
- increased costs of drilling, completing, stimulating, equipping, operating, maintaining and abandoning wells; and
- delays or cost overruns caused by equipment failures, accidents, environmental hazards, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes and other matters.

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 “—Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.” In addition, our cost of drilling, completing and operating wells is often uncertain.

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

- delays imposed by, or resulting from, compliance with regulatory requirements, including limitations on water disposal, emission of greenhouse gases (“GHGs”), steam injection and well stimulation;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for steam used in production or pressure maintenance;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines; and
- other market limitations in our industry.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to property, reserves and equipment, pollution, environmental contamination and regulatory penalties.

We may not drill our identified sites at the times we scheduled or at all.

We have specifically identified locations for drilling over the next several years, which represent a significant part of our long-term growth strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. We make assumptions that may prove inaccurate about the consistency and accuracy of data when we identify these locations. We cannot guarantee that these prospective drilling locations or any other drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these drilling locations. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented approximately 2% of our total net acreage at December 31, 2017.

Our existing debt agreements have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities.

The RBL Facility and the indenture governing our 2026 Notes have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in activities that may be in our long-term best interests. These agreements contain covenants, that, among other things, limit our ability to:

- incur or guarantee additional indebtedness;
- make investments (including certain loans to others);
- merge or consolidate with another entity;
- make dividends and certain other payments in respect of our equity;
- hedge future production or interest rates;
- create liens that secure indebtedness or certain other obligations;
- transfer, sell or otherwise dispose of assets;
- repay or prepay certain indebtedness prior to the due date;
- enter into transactions with affiliates; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, the RBL Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios, which may limit our ability to borrow funds to withstand a future downturn in our business, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of these limitations.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. 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.

The borrowing base under the RBL Facility is subject to periodic redetermination.

The amount available to be borrowed under the RBL Facility is subject to a borrowing base and will be redetermined semiannually on or about each May 1 and November 1 and will depend on the volumes of our estimated proved oil and natural gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent of, or two-thirds of the lenders under, the RBL Facility. We may request one additional redetermination between each regularly scheduled redetermination and the administrative agent and the lenders may request one additional redetermination between each regularly scheduled redetermination. Furthermore, our borrowing base is subject to automatic reductions due to certain asset sales and hedge terminations, the incurrence of certain other debt and other events as provided in the RBL Facility. For example, the RBL Facility currently provides that to the extent we incur certain unsecured indebtedness, our borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt that exceeds the amount, if any, of certain other debt that is being refinanced by such unsecured debt. We could be required to repay a portion of the RBL Facility to the extent that after a redetermination our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans outstanding under the facility, requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

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 future success will depend on our ability to evaluate, select and acquire suitable properties for acquisitions, market our production and secured skilled personnel to operate our assets in a highly competitive environment . Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ greater financial, technical and personnel resources than we do. In California, where we have the most experience operating, our competitors are few and large, which may limit available acquisition opportunities. Our competitors may also 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 historically continually increased due to competition and may increase substantially in the future.

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

There is no guarantee we will be able to identify or complete attractive acquisitions . Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions. Our debt arrangements impose certain limitations on our ability to enter into mergers or combination transactions and to incur certain indebtedness, which could indirectly limit our ability to acquire assets and businesses. See "—Our existing debt agreements have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities." In addition, The success of completed acquisitions will depend on our ability to integrate effectively the acquired business into our existing operations, may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources.

We are dependent on our cogeneration facilities to produce steam for our operations. Viable contracts for the sale of surplus electricity, economic market prices and regulatory conditions affect the economic value of these facilities to our operations.

We are dependent on five cogeneration facilities that, combined, provide approximately 23% of our steam capacity and approximately 43% of our field electricity needs in California at a discount to market rates. To further offset our costs, we sell surplus power to California utility companies produced by three of our cogeneration facilities under long-term contracts. These facilities are dependent on viable contracts for the sale of electricity. Should we lose, be unable to renew on favorable terms, or be unable to replace such contracts, we may be unable to realize the cost offset currently received. Furthermore, market fluctuations in electricity prices and regulatory changes in California could adversely affect the economics of our cogeneration facilities and any corresponding increase in the price of steam could significantly impact our operating costs. If we were unable to find new or replacement steam sources, lose existing sources or experience installation delays, we may be unable to maximize production from our heavy oil assets. If we were to lose our electricity sources, we would be subject to the electricity rates we could negotiate for our needs. For a more detailed discussion of our electricity sales contracts, see "Business—Operational Overview—Electricity."

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 our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including the RBL Facility and our 2026 Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors that may be beyond our control. If oil and natural gas prices were to deteriorate and remain at low levels for an extended period of time, our cash flows from operating activities may be insufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources were 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 indebtedness would depend on the condition of the capital markets and our financial condition at such time, including the view of the markets of our credit risk after recent defaults. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with new covenants that further restrict business operations and opportunities. 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. The RBL Facility and our 2026 Notes currently restrict our ability to dispose of assets and our use of the proceeds from any such disposition. We may not be able to consummate 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.

Future declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in write-downs of the carrying amounts of our assets.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. We evaluate the impairment of our oil and natural gas properties whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Based on 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. For the year ended December 31, 2016, we recorded noncash impairment charges of approximately $1.0 billion.

The inability of one or more of our customers to meet their obligations may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For the nine months ended September 30, 2018, sales of oil, natural gas and NGLs to Andeavor, Phillips 66 and Kern Oil & Refining accounted for approximately 36%, 30% and 14%, respectively, of our sales. For the ten months ended December 31, 2017, sales of oil, natural gas and NGLs to Andeavor, Phillips 66 and Kern Oil & Refining accounted for approximately 37%, 34% and 15%, respectively, of our sales. For the two months ended February 28, 2017, sales of oil, natural gas and NGLs to Andeavor and Phillips 66 accounted for approximately 36% and 31%, respectively, of our sales.

Due to the terms of supply agreements with our customers, we may not know that a customer is unable to make payment to us until almost two months after production has been delivered. This concentration of purchasers may impact our overall credit risk in that these entities may be similarly affected by changes in economic conditions or commodity price fluctuations. We do not require our customers to post collateral. If the purchasers of our oil and natural gas become insolvent, we may be unable to collect amounts owed to us.

Our producing properties are located primarily in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.

We operate primarily in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately influenced by conditions there. These conditions include local price fluctuations, changes in state or regional laws and regulations affecting our operations, limited acquisition opportunities where we have the most operating experience and infrastructure and other regional supply and demand factors, including gathering, pipeline and transportation capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. For a discussion of regulatory risks, see "—Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including well stimulation, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy." The concentration of our operations in California and limited local storage options also increase our exposure to events such as natural disasters, including wildfires, mechanical failures, industrial accidents or labor difficulties.

Operational issues and inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise could restrict access to markets for the commodities we produce.

Our ability to market our production of oil, gas and NGLs depends on a number of factors, including the proximity of production fields to pipelines, refineries and terminal facilities, competition for capacity on such facilities, refinery shutdowns and turnarounds and the ability of such facilities to gather, transport or process our production. If these facilities are unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely, and expect to rely in the future, on third party facilities for services such as storage, processing and transmission of our production. Our plans to develop and sell our reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil, gas and NGLs that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. If our access to markets for commodities we produce is restricted, our costs could increase and our expected production growth may be impaired.

If our assets become subject to FERC regulation or federal, state or local regulations or policies change, or if we fail to comply with market behavior rules, our financial condition, results of operations and cash flows could be materially and adversely affected.

Our gathering and transportation operations are exempt from regulation by the Federal Energy Regulatory Commission ("FERC") FERC, under the Natural Gas Act ("NGA").We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. The distinction between FERC- regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by the FERC, the courts, or Congress. If the FERC were to determine that one of our facilities or the services it provides were not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation, which could decrease revenue, increase operating costs and otherwise adversely affect our results of operations and cash flows. Should we fail to comply with any applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. The FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations in excess of $1 million per day for each violation and disgorgement of profits associated with any violation.

Moreover, FERC regulations indirectly impact our businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, gas quality, capacity release and market center promotion, indirectly affect the intrastate natural gas market.

In addition, State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take and common purchaser requirements, as well as complaint-based rate regulation. Other state regulations may not directly apply to our business, but may nonetheless affect the availability of natural gas for purchase, compression and sale.

For more information regarding federal and state regulation of our operations, please see "Business—Regulation of Health, Safety and Environmental Matters."

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation. In addition, potential future legislation may generally affect the taxation of natural gas and oil exploration and development companies, and may adversely affect our operations.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to natural gas and oil exploration and development companies. Such legislative proposals have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. The future passage of any legislation as a result of these proposals or other changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development or otherwise significantly increase our costs

Furthermore, in California, there have been proposals for new taxes on oil and natural gas production. Although the proposals have not become law, campaigns by various interest groups could lead to future additional oil and natural gas severance or other taxes. The imposition of such taxes could significantly reduce our profit margins and cash flow and otherwise significantly increase our costs.

Derivatives legislation and regulations could have an adverse effect on our ability to use derivative instruments to reduce the risks associated with our business.

The Dodd-Frank Act, enacted in 2010, establishes federal oversight and regulation of the over-the-counter ("OTC") derivatives market and entities, like us, that participate in that market. The Dodd-Frank Act required the Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to OTC derivatives transactions, and these rules may affect both the size of positions that we may hold and the ability or willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, such changes could materially reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices. While many Dodd-Frank Act regulations are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

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 or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to, or otherwise be affected by, such regulations. At this time, the impact of such regulations is not clear.

Concerns about climate change and other air quality issues may affect our operations or results.

Concerns about climate change and regulation of GHGs and other air quality issues may materially affect our business in many ways, including by increasing the costs to provide our products and services, and reducing demand for, and consumption of, the oil and gas we produce. We may be unable to recover or pass through all or any of these costs. In addition, legislative and regulatory responses to such issues may increase our operating costs and render certain wells or projects uneconomic. To the extent financial markets view climate change and GHG emissions as a financial risk, this could adversely impact our cost of, and access to, capital. Both California and the United States Environmental Protection Agency ("EPA") have adopted laws and policies that seek to reduce GHG emissions as discussed in "Business—Regulation of Health, Safety and Environmental Matters—Climate Change" and "Business—Regulation of Health, Safety and Environmental Matters—California GHG Regulations." Compliance with California cap and trade program laws and regulations could significantly increase our capital, compliance and operating costs and could also reduce demand for the oil and natural gas we produce. The cost of acquiring GHG emissions allowances will depend on the market price for such instruments at the time they are purchased, the distribution of cost-free allowances among various industry sectors by the California Air Resources Board, and our ability to limit GHG emissions and implement cost-containment measures. In addition, on September 10, 2018, the Governor of California signed into law a bill that would commit California to the use of 100% zero-carbon electricity by 2045. The same day, the Governor also signed an executive order committing California to total economy-wide carbon neutrality by 2045. While the law does not directly affect the oil and gas industry, and it remains unclear what actions state agencies may take in response to the executive order, these recent actions could result in decreased future demand for the oil and gas we produce and in turn have an adverse effect on our business and results of operations.

In addition, other current and proposed international agreements and federal and state laws, regulations and policies seek to restrict or reduce the use of petroleum products in transportation fuels and electricity generation, impose additional taxes and costs on producers and consumers of petroleum products, and require or subsidize the use of renewable energy.

Governmental authorities can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act ("CAA") and associated state laws and regulations. For example, the San Joaquin Valley will be required to adopt more rigorous attainment plans under the CAA to comply with federal ozone and particulate matter standards, and these efforts could affect our activities in the region. In addition, California air quality laws and regulations, particularly in southern and central California where most of our operations are located, are in most instances more stringent than analogous federal laws and regulations.

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

We are not fully insured against all risks. Our oil and natural gas exploration and production activities, including well drilling, completion, stimulation, maintenance, marketing and transportation and abandonment activities, are subject to operational risks such as fires, explosions, 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, equipment failures and industrial accidents. We are exposed to similar risks indirectly through our customers and other market participants such as refiners. Other catastrophic events such as earthquakes, floods, mudslides, fires, droughts, terrorist attacks and other events that cause operations to cease or be curtailed may adversely affect our business and the communities in which we operate. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and natural gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. We are also subject to litigation related to the Chapter 11 Proceedings. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have a material adverse impact on us because of legal costs, diversion of the attention of management and other personnel and other factors. In addition, resolution of one or more such proceedings could result in liability, loss of contractual or other rights, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change materially from one period to the next.

The loss of senior management or technical personnel could adversely affect operations.

We depend on, and could be deprived of, the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of services of any of these individuals.

Information technology failures and cyber attacks could affect us significantly.

We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected.

We face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations. If we were to experience an attack and our security measures failed, the potential consequences to our business and the communities in which we operate could be significant and could harm our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Risks Related to Emergence

We recently emerged from bankruptcy, which could adversely affect our business and relationships.

The Chapter 11 Proceedings and our recent emergence from bankruptcy could adversely affect our business and relationships with customers, vendors, royalty and working interest owners, employees, service providers and suppliers. The following are among the risks associated with our emergence:

- vendors or other contract counterparties could terminate their relationship or require financial assurances or enhanced performance;

- our ability to renew existing contracts and compete for new business may be adversely affected; and

- our ability to attract, motivate and retain key executives and employees may be adversely affected.

Our financial condition or results of operations are not comparable to the financial condition or results of operations reflected in our historical financial statements.

Since February 28, 2017, we have been operating under a new capital structure. In addition, we adopted fresh-start accounting and, as a result, at February 28, 2017 our assets and liabilities were recorded at fair value, which resulted in values that are materially different than the values that were recorded in our historical financial statements. Accordingly, our financial condition and results of operations from and after the Effective Date are not comparable to the financial condition or results of operations reflected in our historical financial statements. Further, as a result of the implementation of the Plan and the transactions contemplated thereby, our historical financial information may not be indicative of our future financial performance.

Due to our limited operating history as an independent company following our emergence from bankruptcy in February 2017, we have been in the process of establishing our accounting and other management systems and resources. We may be unable to effectively develop a mature system of internal controls, and a failure of our control systems to prevent error or fraud may materially harm our company.

Our predecessor company was an indirect, wholly owned subsidiary of Linn Energy, and we utilized Linn Energy’s systems, software and personnel to prepare our financial information and to ensure that adequate internal controls over financial reporting were in place. Following our emergence from bankruptcy in February 2017, we assumed responsibility for these functions. In the course of transitioning these functions, we put in place a new executive management team and continue to add personnel, upgrade our systems, including information technology, and implement additional financial and managerial controls, reporting systems and procedures. These activities place significant demands on our management, administrative and operational resources, including accounting resources, and involve risks relating to our failure to manage this transition adequately.

Proper systems of internal controls over financial accounting and disclosure controls and procedures are critical to our business. If we are unable to effectively develop a mature system of internal controls, we may be unable to reliably assimilate and compile financial information about our company, which would significantly impair our ability to prevent error, detect fraud or access capital markets.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect resource constraints and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. Failure of our control systems to prevent error or fraud could materially adversely impact us.

Our limited operating history makes it difficult to evaluate our business plan and our long-term viability cannot be assured.

Our prospects for financial success are difficult to assess because we have a limited operating history since emergence from bankruptcy. There can be no assurance that our business will be successful, that we will be able to maintain a profitable operation, or that we will not encounter unforeseen difficulties that may deplete our capital resources more rapidly than anticipated. There can be no assurance that we will sustain profitability or positive cash flows from our operating activities.

Following our emergence from bankruptcy, we are under the management of a new board of directors.

Currently, our board of directors is made up of six directors, none of whom were involved in the management of our business prior to our bankruptcy. The new directors have different backgrounds, experiences and perspectives from those individuals who previously managed us and, thus, may have different views on our direction and the issues that will determine our future. The effect of implementation of those views may be difficult to predict and they may not lead us to achieve the goals we have set forth in this prospectus and elsewhere.

Additionally, the ability of our new directors to quickly expand their knowledge of our operations, strategies and technologies will be critical to their ability to make informed decisions about our strategy and operations, particularly given the competitive environment in which our business operates. If our board of directors is not sufficiently informed to make these decisions, our ability to compete effectively and profitably could be adversely affected.

One of our directors is also affiliated with entities holding a significant percentage of our stock. See "Risks Related to our Capital Stock—There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders."

Risks Related to our Capital Stock

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

A large portion of our common stock is beneficially owned by a relatively small number of stockholders. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures, hostile takeovers or other transactions, including the payment of dividends or the issuance of additional equity or debt, that, in their judgment, could enhance their investment in Berry Corp. or another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common stock because investors may perceive disadvantages in owning shares in companies with significant stockholder concentrations.

Our significant stockholders and their affiliates are not limited in their ability to compete with us, and the corporate opportunity provisions in the Certificate of Incorporation could enable our significant stockholders to benefit from corporate opportunities that might otherwise be available to us.

Our governing documents provide that our stockholders and their affiliates are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In particular, subject to the limitations of applicable law, the Amended and Restated Certificate of Incorporation of Berry Corp. (the “Certificate of Incorporation”), among other things:

- permits stockholders to make investments in competing businesses; and

- provides that if one of our directors who is also an employee, officer or director of a stockholder (a “Dual Role Person”) becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

Our director that is a Dual Role Person may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which our stockholders have invested, in which case we may not become aware of, or otherwise have the ability to pursue, such opportunity. Further, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to be unavailable to us or causing them to be more expensive for us to pursue. In addition, our stockholders and their affiliates may dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. Our business and prospects could be adversely affected if attractive business opportunities are procured by our stockholders for their own benefit rather than for ours.

Certain of our stockholders and their affiliates have resources greater than ours, which may make it more difficult for us to compete with such persons with respect to commercial activities as well as for potential acquisitions. As a result, competition from certain stockholders and their affiliates could adversely impact our results of operations.

Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

As of November 29, 2018, there were 81,651,098 shares of our common stock outstanding. This registration statement registers the resale by certain of our stockholders of 61,420,234 shares of our common stock pursuant to our amended and restated registration rights agreement with the selling stockholders identified in this prospectus (the “Registration Rights Agreement”). Such selling stockholders also have the right to demand the Company to support underwritten sales of such shares, subject to the limitations specified in the Registration Rights Agreement. These selling stockholders could sell a large number of shares into the public market following the expiration of their IPO lock-up agreements on January 21, 2019, or earlier if Goldman Sachs & Co. LLC and Wells Fargo Securities, LLC were to waive the restrictions under the lock-up agreements, which could cause the price of our common stock to significantly decline.

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or securities convertible into shares of our common stock. The Certificate of Incorporation provides that Berry Corp.’s authorized capital stock consists of 750,000,000 shares of common stock and 250,000,000 shares of preferred stock.

The issuance of any securities for acquisitions, financing, upon conversion or exercise of convertible securities, or otherwise may result in a reduction of the book value and market price of our outstanding common stock. If we issue any such additional securities, the issuance will cause a reduction in the proportionate ownership and voting power of all current stockholders. We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Shares of our common stock are also reserved for issuance as equity-based awards to employees, directors and certain other persons under the Berry Petroleum Corporation 2017 Omnibus Incentive Plan, as amended and restated (our "Restated Incentive Plan"). We have filed a registration statement with the SEC on Form S-8 providing for the registration of shares of our common stock issued or reserved for issuance under our Restated Incentive Plan. Subject to the satisfaction of vesting conditions, the expiration of certain lock-up agreements and the requirements of Rule 144, shares registered under the registration statement on Form S-8 may be made available for resale immediately in the public market without restriction. Investors may experience dilution in the value of their investment upon the exercise of any equity awards that may be granted or issued pursuant to the Restated Incentive Plan in the future.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

The Certificate of Incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

We are an “emerging growth company,” and are able take advantage of reduced disclosure requirements applicable to “emerging growth companies,” which could make our common stock less attractive to investors.

We are an “emerging growth company” and, for as long as we continue to be an “emerging growth company,” we intend to take advantage of certain exemptions from various reporting requirements, including auditor attestation requirements or any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We could be an “emerging growth company” for up to five years, or until the earliest of (i) the last day of the first fiscal year in which our annual gross revenues exceed $1.07 billion, (ii) the date that we become a “large accelerated filer” as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), which would occur if the market value of our common stock that is held by non-affiliates exceeds $700 million as of the last business day of our most recently completed second fiscal quarter, or (iii) the date on which we have issued more than $1 billion in non-convertible debt during the preceding three-year period.

“Emerging growth companies” can also delay adopting new or revised accounting standards until such time as those standards apply to private companies. We intend to take advantage of the reduced reporting requirements and exemptions, including the longer phase-in periods for the adoption of new or revised financial accounting standards under Section 107 of the JOBS Act until we are no longer an emerging growth company. Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those companies who will comply with new or revised financial accounting standards. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable pursuant to Section 107 of the JOBS Act.

To the extent investors find our common stock less attractive as a result of our reduced reporting and exemptions, there may be a less active trading market for our common stock, and our stock price may be more volatile.

We will incur significant costs and devote substantial management time as a result of operating as a public company, particularly after we are no longer an “emerging growth company.”

Our management and other personnel are required to divert attention from operational and other business matters to devote substantial time to public company requirements. After we no longer qualify as an “emerging growth company,” we expect to incur additional management time and cost to comply with the more stringent reporting requirements applicable to companies that are deemed accelerated filers or large accelerated filers, including complying with the auditor attestation requirements of Section 404(b) of the Sarbanes-Oxley Act. We currently do not have an internal audit function, and we have needed, and will continue to need, to hire or contract for additional accounting and financial staff with appropriate public company experience and technical accounting knowledge.

If we do not develop or maintain all required financial reporting and disclosure procedures and controls, we may be unable to provide the financial information required of a U.S. publicly traded company in a timely and reliable manner.

Prior to the IPO, we were not required to adopt or maintain all of the financial reporting and disclosure procedures and controls required of a U.S. publicly traded company because we were a privately held company. If we fail to develop and maintain effective internal controls and procedures and disclosure procedures and controls, we may be unable to provide the financial information and SEC reports that a U.S. publicly traded company is required to provide in a timely and reliable fashion. Any such delays or deficiencies could penalize us, including by limiting our ability to obtain financing, either in the public capital markets or from private sources and hurt our reputation and could thereby impede our ability to implement our growth strategy.

Our internal control over financial reporting is not currently required to meet the standards required by Section 404 of the Sarbanes-Oxley Act, but failure to achieve and maintain effective internal control over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act in the future could have a material adverse effect on our business and share price.

Section 404 of the Sarbanes-Oxley Act requires annual management assessments of the effectiveness of our internal control over financial reporting, starting with the second annual report that we file with the SEC after the consummation of the IPO, and generally requires a report by our independent registered public accounting firm on the effectiveness of our internal control over financial reporting. However, under the JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act until we are no longer an "emerging growth company," which could be up to five years from our IPO.

Effective internal controls are necessary for us to provide reliable financial reports, safeguard our assets, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports, safeguard our assets or prevent fraud, our reputation and operating results could be harmed. The rules governing the standards that must be met for our management to assess our internal control over financial reporting are complex and require significant documentation, testing and possible remediation.

In connection with the implementation of the necessary procedures and practices related to internal control over financial reporting, we may identify deficiencies that we may not be able to timely remediate. In addition, we may encounter problems or delays in completing the implementation of any remediation of control deficiencies and receiving a favorable attestation in connection with the attestation provided by our independent registered public accounting firm. Further, failure to achieve and maintain an effective internal control environment could have a material adverse effect on our business and share price and could limit our ability to report our financial results accurately and timely.

Certain provisions of the Certificate of Incorporation and Bylaws, as well as the Stockholders Agreement, may make it difficult for stockholders to change the composition of our board of directors and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of the Certificate of Incorporation and the Form of the Second Amended and Restated Bylaws of Berry Corp. (the "Bylaws") may have the effect of delaying or preventing changes in control if our board of directors determines that such changes in control are not in the best interests of Berry Corp. and our stockholders. For example, the Certificate of Incorporation and Bylaws include provisions that (i) authorize our board of directors to issue "blank check" preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval and (ii) establish advance notice procedures for nominating directors or presenting matters at stockholder meetings. Additionally, we and many of the largest holders of our equity securities are bound by a stockholders agreement that requires us to nominate for election and take all other necessary actions to cause an individual designated by Benefit Street Partners to be included in the slate of nominees recommended by the board of directors to be elected to the board of directors.

These provisions could enable the board of directors to delay or prevent a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may discourage or prevent attempts to remove and replace incumbent directors. These provisions may also discourage or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, which is responsible for appointing the members of our management.

Our Certificate of Incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers or other employees to us or our stockholders, (iii) any action asserting a claim against us, our directors, officers or employees arising pursuant to any provision of the Delaware General Corporation Law (the "DGCL"), our Certificate of Incorporation or our Bylaws or (iv) any action asserting a claim against us, our directors, officers or employees that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having subject matter jurisdiction and personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our common stock will be deemed to have notice of, and consented to, the provisions of our Certificate of Incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our Certificate of Incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, maintenance capital requirements, expected production and costs, reserves, hedging activities, capital investments and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect our results of operations and financial position appear under the heading “Risk Factors”.

Factors (but not necessarily all the factors) that could cause results to differ include among others:

- volatility of oil, natural gas and NGL prices;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures and meet working capital requirements;
- price and availability of natural gas;
- our ability to use derivative instruments to manage commodity price risk;
- impact of environmental, health and safety, and other governmental regulations, and of current, pending, or future legislation;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our inability to replace our reserves through exploration and development activities;
- our ability to obtain permits and otherwise to meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- effects of competition;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- our ability to improve our financial results and profitability following our emergence from bankruptcy and other risks and uncertainties related to our emergence from bankruptcy;
- changes in tax laws;
- impact of derivatives legislation affecting our ability to hedge;
- ineffectiveness of internal controls;
- concerns about climate change and other air quality issues;
- catastrophic events;

- litigation;
- our ability to retain key members of our senior management and key technical employees; and
- information technology failures or cyber attacks.

Except as required by law, we undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

All forward-looking statements, expressed or implied, included in this report 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.

USE OF PROCEEDS

We will not receive any proceeds from the sale of shares by the selling stockholders pursuant to this prospectus. In addition, we have agreed to pay certain expenses, other than underwriting discounts and commissions, of the selling stockholders in connection with the sale of common stock from time to time. Please read "Plan of Distribution".

DIVIDEND POLICY

On August 21, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock on a pro-rated basis from the date of our IPO through September 30, 2018, or $0.09 per share, which was paid on October 15, 2018 to stockholders of record as of September 15, 2018. On November 7, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the fourth quarter of 2018. We currently anticipate continuing to pay a quarterly cash dividend of $0.12 per share on our common stock.

The payment of future dividends, if any, will be determined by our board of directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors.

SELECTED HISTORICAL FINANCIAL DATA

The following table shows the selected historical financial information, for the periods and as of the dates indicated, of our predecessor company (Berry LLC) and successor company (Berry Corp.). The selected historical financial information as of and for the year ended December 31, 2016 is derived from the audited historical financial statements of our predecessor company included elsewhere in this prospectus. The selected historical financial information as of and for the two months ended February 28, 2017 is derived from audited financial statements of our predecessor company included elsewhere in this prospectus. The selected historical financial information for the ten months ended December 31, 2017 is derived from audited consolidated financial statements of the successor company included elsewhere in this prospectus. The selected historical financial information for the seven months ended September 30, 2017, and as of and for the nine months ended September 30, 2018 is derived from unaudited consolidated financial statements of Berry Corp. included elsewhere in this prospectus.

Upon Berry LLC's emergence from bankruptcy on February 28, 2017, or the Effective Date, in connection with the Plan, Berry LLC adopted fresh-start accounting and was recapitalized, which resulted in Berry LLC becoming a wholly-owned subsidiary of Berry Corp. and Berry Corp. being treated as the new entity for financial reporting. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. These fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in our predecessor company's historical balance sheet. The effects of the Plan and the application of fresh-start accounting are reflected in Berry Corp.'s consolidated financial statements as of the Effective Date and the related adjustments thereto are recorded in our consolidated statements of operations as reorganization items for the periods prior to the Effective Date. As a result, our consolidated financial statements subsequent to the Effective Date are not comparable to our financial statements prior to such date. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material. You should read the following table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," the historical financial statements of our predecessor and accompanying notes included elsewhere in this prospectus.

	Berry Corp. (Successor)			Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(unaudited)	(audited)	(unaudited)	(audited)	(audited)
			($ in thousands)		
Statements of Operations Data:					
Oil, natural gas and NGL sales	$ 410,013	$ 357,928	$ 237,324	$ 74,120	$ 392,345
Electricity sales	25,691	21,972	15,517	3,655	23,204
(Losses) gains on oil and natural gas derivatives	(131,781)	(66,900)	5,642	12,886	(15,781)
Marketing revenues	1,788	2,694	1,901	633	3,653
Other revenues	500	3,975	3,902	1,424	7,570
Lease operating expenses	137,468	149,599	105,014	28,238	185,056
Electricity generation expenses	13,855	14,894	10,193	3,197	17,133
Transportation expenses	7,640	19,238	18,645	6,194	41,619
Marketing expenses	1,424	2,320	1,674	653	3,100
General and administrative expenses[1]	37,896	56,009	43,529	7,964	79,236
Depreciation, depletion and amortization	62,017	68,478	48,393	28,149	178,223
Impairment of long-lived assets	—	—	—	—	1,030,588
Taxes, other than income taxes	25,288	34,211	25,112	5,212	25,113

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	Berry Corp. (Successor)			Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(unaudited)	(audited)	(unaudited)	(audited)	(audited)
			($ in thousands)		
Losses (gains) on natural gas derivatives	(1,879)	—	—	—	—
(Gains) losses on sale of assets and other, net	522	(22,930)	(20,687)	(183)	(109)
Interest expense	26,828	18,454	12,482	8,245	61,268
Other (income) expense, net	(135)	(4,071)	(4,071)	63	182
Reorganization items, net (income) expense	(23,192)	1,732	1,001	507,720	72,662
Income tax (benefit) expense	3,145	2,803	9,189	230	116
Net income (loss)	15,334	(21,068)	13,812	(502,964)	(1,283,196)
Conversion and Dividends on Series A preferred stock	(97,942)	(18,248)	(12,681)	n/a	n/a
Net income (loss) available to common stockholders	(82,608)	(39,316)	1,131	n/a	n/a
Net income (loss) per share of common stock[5]					
Basic	$ (1.59)	$ (0.98)	$ 0.03	n/a	n/a
Diluted	$ (1.59)	$ (0.98)	$ 0.03	n/a	n/a
Weighted average common stock outstanding					
Basic	51,900	40,000	40,000	n/a	n/a
Diluted[2]	51,900	40,000	40,602	n/a	n/a
Cash Flow Data:					
Net cash provided by (Used in)					
Operating activities	$ 7,334	$ 107,399	$ 70,505	$ 22,431	$ 13,197
Capital expenditures	(85,752)	(65,479)	(49,942)	(3,158)	(34,796)
Acquisitions, sales of properties and other investing activities	3,377	(15,046)	(24,621)	25	194
Balance Sheet Data:					
(at period end)					
Total assets	$ 1,539,607	$ 1,546,402	$ 1,579,389	$ 1,561,038	$ 2,652,050
Current portion of long-term debt	—	—	—	—	891,259
Long-term debt, net	391,512	379,000	379,000	400,000	—
Series A Preferred Stock	—	335,000	335,000	335,000	—
Stockholders' and/or member's equity	889,110	859,310	877,541	878,527	502,963
Other Financial Data:					
Adjusted EBITDA[3]	$ 176,256	$ 149,613	$ 96,773	$ 28,845	$ 89,646
Adjusted General and Administrative Expenses[4]	29,133	23,865	$ 15,206	7,964	79,236

(1) Includes non-recurring restructuring and other costs and non-cash stock compensation expense of, $8.8 million for the nine months ended September 30, 2018, $32.1 million for the ten months ended December 31, 2017 and $28.3 million for the seven months ended September 30, 2017.

(2) The Series A Preferred Stock was not a participating security; therefore, we calculated diluted earnings per share using the "if-converted" method, under which the preferred dividends are added back to the numerator and the Series A Preferred Stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock were included in the diluted earnings per share calculation for

the nine months ended September 30, 2018 and the ten months ended December 31, 2017 as their effect was antidilutive under the "if-converted" method. In July 2018, all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO. Please see "—Recent Developments—Initial Public Offering and Series A Preferred Stock Conversion."

(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Prospectus Summary—Summary Historical and Pro Forma Financial Information—Non-GAAP Financial Measures."

(4) Adjusted General and Administrative Expenses is a non-GAAP financial measure. For a definition of Adjusted General and Administrative Expenses and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Prospectus Summary—Summary Historical and Pro Forma Financial Information—Non-GAAP Financial Measures.

(5) Dividends declared on common stock for the three months ended September 30, 2018 was $0.09/share.

PRO FORMA FINANCIAL DATA

The following unaudited pro forma condensed consolidated financial information of Berry Corp. gives effect to the Plan and related transactions and fresh-start accounting, the Hugoton Disposition, the 2026 Notes issuance, the Series A Preferred Stock Conversion and the IPO. Prior to the Effective Date, Berry Corp. had not conducted any business operations. Accordingly, the unaudited pro forma condensed consolidated financial statements are based on the historical financial statements of the Company's wholly owned subsidiary, Berry LLC. The unaudited pro forma condensed consolidated statements of operations are presented for the nine months ended September 30, 2018 and the year ended December 31, 2017. This unaudited pro forma condensed consolidated financial information should be read in conjunction with Berry Corp.'s historical consolidated financial statements as of and for nine months ended September 30, 2018 and for the ten months ended December 31, 2017 and with Berry LLC's historical financial statements for the two months ended February 28, 2017 included in this prospectus.

The unaudited pro forma condensed consolidated statements of operations for the year ended December 31, 2017 give effect to (1) the Plan and related transactions and fresh-start accounting, (2) the Hugoton Disposition, (3) the 2026 Notes issuance and (4) the Series A Preferred Stock Conversion and the IPO as if each had been completed as of January 1, 2017. The unaudited pro forma financial statements do not give effect to the Hill Acquisition because that transaction was not deemed significant under Rule 3-05 of the SEC's Regulation S-X, so it is not required to be presented herein.

The unaudited pro forma condensed consolidated statements of operations for the nine months ended September 30, 2018 give effect to (1) the 2026 Notes issuance and (2) the Series A Preferred Stock Conversion and the IPO as if each had been completed as of January 1, 2017.

The unaudited pro forma condensed consolidated financial statements are for informational and illustrative purposes only and are not necessarily indicative of the financial results that would have been had the events and transactions occurred on the dates assumed, nor are such financial statements necessarily indicative of the results of operations in future periods. The unaudited pro forma condensed consolidated financial statements do not include cost savings resulting from the Plan. The pro forma adjustments, as described in the accompanying notes, are based upon currently available information. The historical financial information has been adjusted to give effect to pro forma adjustments that are (i) directly attributable to the Plan becoming effective, fresh-start accounting, the Hugoton Disposition, the 2026 Notes issuance, the Series A Preferred Stock Conversion, the IPO and the application of net proceeds from the IPO, (ii) factually supportable, and (iii) expected to have a continuing impact on the Company's consolidated results.

Background

On May 11, 2016, the Linn Entities and Berry LLC filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code (the "Bankruptcy Code") in Bankruptcy Court. On January 27, 2017, the Bankruptcy Court entered its confirmation order approving and confirming the Plan (the "Confirmation Order"). A final decree closing the Chapter 11 Proceedings was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters.

In anticipation of the effectiveness of the Plan, Berry Corp. was formed for the purpose of having all the membership interests of Berry LLC assigned to it upon Berry LLC's emergence from bankruptcy.

On the Effective Date, the Plan became effective and was implemented in accordance with its terms. Among other transactions, 100% of Berry LLC's outstanding membership interests were transferred to Berry Corp. As a result, Berry LLC emerged from bankruptcy as a wholly owned subsidiary of Berry Corp., separate from Linn Energy and its affiliates.

Plan of Reorganization and Fresh-Start Accounting

On the Effective Date, Berry LLC consummated the following reorganization transactions in accordance with the Plan:

- Linn Acquisition Company, LLC transferred 100% of the outstanding membership interests in Berry LLC to Berry Corp. pursuant to an assignment agreement, dated February 28, 2017, between Linn Acquisition Company, LLC and Berry Corp. (the “Assignment Agreement”). Under the Assignment Agreement, Berry LLC became a wholly owned operating subsidiary of Berry Corp.

- The holders of claims under Berry LLC’s Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry LLC, as borrower, Wells Fargo Bank, N.A., as administrative agent, and certain lenders (as amended, the “Pre-Emergence Credit Facility”), received (i) their pro rata share of a cash paydown and (ii) pro rata participation in a new facility (the “Emergence Credit Facility”). As a result, all outstanding obligations under the Pre-Emergence Credit Facility were canceled and the agreements governing these obligations were terminated.

- Berry LLC, as borrower, entered into the Emergence Credit Facility with the holders of claims under the Pre-Emergence Credit Facility, as lenders, and Wells Fargo Bank, N.A., as administrative agent, providing for a new reserve-based revolving loan with up to $550 million in borrowing commitments. For additional information about the Emergence Credit Facility, see Note 5 of our 2017 consolidated financial statements.

- The holders of Berry LLC’s 6.75% senior notes due 2020, and 6.375% senior notes due 2022 (collectively, the “Unsecured Notes”), received a right to their pro rata share of (i) either 32,920,000 shares of common stock in Berry Corp. or, for those non-accredited investors holding the Unsecured Notes that irrevocably elected to receive a cash recovery, cash distributions from a $35 million cash distribution pool (the “Cash Distribution Pool”) and (ii) specified rights to participate in a two-tranche offering of rights to purchase Series A Preferred Stock at an aggregate purchase price of $335 million (as further defined in the Plan, the “Berry Rights Offerings”). As a result, all outstanding obligations under the Unsecured Notes were canceled, and the indentures and related agreements governing these obligations were terminated.

- The holders of unsecured claims against Berry LLC (other than the Unsecured Notes) (the “Unsecured Claims”) received a right to their pro rata share of either (i) 7,080,000 shares of common stock in Berry Corp., or (ii) in the event that such holder irrevocably elected to receive a cash recovery, cash distributions from the Cash Distribution Pool. The obligations arising from the Unsecured Claims were extinguished.

Upon the Company’s emergence from bankruptcy, it was required to adopt fresh-start accounting, which, with the recapitalization described above, resulted in Berry Corp. being treated as the new entity for financial reporting purposes. The Company was required to adopt fresh-start accounting upon its emergence from bankruptcy because (i) the holders of existing voting ownership interests of our predecessor company received less than 50% of the voting shares of Berry Corp. and (ii) the reorganization value of the Company’s assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims. An entity applying fresh-start accounting upon emergence from bankruptcy is viewed as a new reporting entity from an accounting perspective, and accordingly, may select new accounting policies.

The Plan and disclosure statement approved by the Bankruptcy Court did not include an enterprise value or reorganization value, nor did the Bankruptcy Court approve a value as part of its confirmation of the Plan. The Company determined a value to be assigned to the equity of the emerging entity as of the date of adoption of fresh-start accounting. Based on the various estimates and assumptions necessary for fresh-start accounting, the Company estimated its enterprise value as of the Effective Date to be approximately $1.3 billion. Reorganization value is derived from an estimate of enterprise value, or the fair value of the Company’s long-term debt, stockholders’ equity and working capital. Reorganization value approximates the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. The enterprise value was estimated using a sum of the parts approach. The sum of parts approach represents the summation of the indicated fair value of the component assets of the Company. The fair value of the Company's assets was estimated by relying on a combination of the income, market and cost approaches.

The reorganization value was allocated to the Company's individual assets generally based on their estimated fair values. For purposes of the accompanying unaudited pro forma condensed consolidated statements of operations, the Company utilized its estimated enterprise value as of the Effective Date and applied such enterprise value as of January 1, 2017. Preparation of an actual valuation with assumptions and economic data as of January 1, 2017 would likely result in an enterprise value that is materially different than such valuation as of the Effective Date. The intent of the unaudited pro forma condensed consolidated financial statements is to illustrate the effects of the Plan based on the underlying economic factors as of the Effective Date.

Hugoton Disposition

The Company closed on the sale of its interests in the Hugoton natural gas field, located primarily in Kansas, effective July 31, 2017.

Issuance of 2026 Notes

In February 2018, we completed a private issuance of $400 million in aggregate principal amount of 7.00% senior unsecured notes due 2026, which resulted in net proceeds of approximately $391 million after deducting expenses and the initial purchasers' discount. A portion of these proceeds were used to repay borrowings under the RBL Facility and the remainder for general corporate purposes.

Series A Preferred Stock Conversion and Common Stock Offering

In connection with the IPO, we amended the Series A Preferred Stock certificate of designation to provide for the automatic conversion of all outstanding shares of Series A Preferred Stock. Pursuant to the amendment, each outstanding share of Series A Preferred Stock was automatically converted into (i) 1.05 shares of common stock and (ii) the right to receive $1.75, minus the amount of any cash dividend paid by the Company on such share of Series A Preferred Stock in respect of any period commencing on or after April 1, 2018.

Of the approximately $111 million of net proceeds we received in the IPO, we used approximately $105 million to repay borrowings under our RBL Facility. This included $60 million we borrowed on the RBL Facility to make the payment due to the holders of our Series A Preferred Stock in connection with the conversion of preferred stock to common stock. We used the remainder for general corporate purposes.

In connection with the IPO, on July 17, 2018, we entered into stock purchase agreements with certain funds affiliated with Oaktree Capital Management and Benefit Street Partners, pursuant to which we purchased an aggregate of 410,229 and 1,391,967 shares of our common stock, respectively, or 1,802,196 in total. In addition to 8,695,653 shares of common stock issued and sold for our benefit in the IPO, we simultaneously received $24 million for issuing and selling 1,802,196 shares to the public and paid $24 million to purchase 1,802,196 shares under the stock purchase agreements. We purchased the shares immediately following the closing of the IPO and retired and returned them to the status of authorized but unissued shares.

The selling shareholders sold an additional 2,545,630 shares at a price to the public of $14.00 per share for which we did not receive any proceeds.

BERRY PETROLEUM CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS FOR NINE MONTHS ENDED SEPTEMBER 30, 2018 ($ in thousands, except per share amounts)

	Berry Corp. (Successor) Nine Months Ended September 30, 2018	Issuance of 2026 Notes Adjustments	Series A Preferred Stock Conversion and Common Stock Offering Adjustments	Berry Corp. (Successor) Pro Forma
Revenues and other:				
Oil, natural gas and NGL sales	$ 410,013	$ —	$ —	$ 410,013
Electricity sales	25,691			25,691
Gains (losses) on oil and natural gas derivatives	(131,781)			(131,781)
Marketing revenues	1,788			1,788
Other revenues	500			500
Total revenues and other	306,211	—	—	306,211
Expenses and other:				
Lease operating expenses	137,468			137,468
Electricity generation expenses	13,855			13,855
Transportation expenses	7,640			7,640
Marketing expenses	1,424			1,424
General and administrative expenses	37,896			37,896
Depreciation, depletion and amortization	62,017			62,017
Taxes, other than income taxes	25,288			25,288
Gains on natural gas derivatives	(1,879)			(1,879)
Gains on sale of assets and other, net	522			522
Total expenses and other	284,231	—	—	284,231
Other income and (expenses):				
Interest expense, net of amounts capitalized	(26,828)	(122) (j)		(26,950)
Other, net	135			135
Total other income (expenses)	(26,693)	(122)	—	(26,815)
Reorganization items, net	23,192			23,192
Income (loss) income before income taxes	18,479	(122)	—	18,357
Income tax expense (benefit)	3,145	(21) (k)		3,124
Net income (loss)	15,334	(101)	—	15,233
Series A preferred stock dividends and conversion to common stock	(97,942)		97,942 (n)	—
Net income (loss) available to common stockholders	$ (82,608)	$ (101)	$ 97,942	$ 15,233
Net income (loss) per share of common stock:				
Basic	$ (1.59)			$ 0.18
Diluted	$ (1.59)			$ 0.18
Weighted average common shares outstanding				
Basic	51,900 (o)		34,523 (l) (m)	86,423
Diluted	51,900 (o)		34,710 (l) (m)	86,610

BERRY PETROLEUM CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS FOR YEAR ENDED DECEMBER 31, 2017

($ in thousands)

	Berry Corp. (Successor)	Berry LLC (Predecessor)					
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Plan of Reorganization and Fresh-Start Accounting Adjustments	Hugoton Disposition Adjustments	Issuance of 2026 Notes Adjustments	Series A Preferred Stock Conversion and Common Stock Offering Adjustments	Berry Corp. (Successor) Pro Forma
Revenues and other:							
Oil, natural gas and NGL sales	$ 357,928	$ 74,120	$ —	$ (37,842) (f)			$ 394,206
Electricity sales	21,972	3,655	—	—			25,627
Gains (losses) on oil and natural gas derivatives	(66,900)	12,886	—	—			(54,014)
Marketing revenues	2,694	633	—	—			3,327
Other revenues	3,975	1,424	—	(5,265) (f)			134
	319,669	92,718	—	(43,107)			369,280
Expenses:							
Lease operating expenses	149,599	28,238	—	(6,129) (g)			171,708
Electricity generation expenses	14,894	3,197	—	—			18,091
Transportation expenses	19,238	6,194	—	(10,007) (g)			15,425
Marketing expenses	2,320	653	—	—			2,973
General and administrative expenses	56,009	7,964	—	(1,292) (g)			62,681
Depreciation, depletion and amortization	68,478	28,149	(14,105) (a)	(6,685) (h)			75,837
Taxes, other than income taxes	34,211	5,212	—	(4,868) (g)			34,555
Gains on sale of assets and other, net	(22,930)	(183)	—	22,930 (i)			(183)
	321,819	79,424	(14,105)	(6,051)			381,087
Other income and (expenses):							
Interest expense, net of amounts capitalized	(18,454)	(8,245)	4,930 (b)	—	(9,341) (j)		(31,110)
Other, net	4,071	(63)	—	—			4,008
	(14,383)	(8,308)	4,930	—	(9,341)		(27,102)
Reorganization items, net	(1,732)	(507,720)	507,720 (c)	—			(1,732)
(Loss) income before income taxes	(18,265)	(502,734)	526,755	(37,056)	(9,341)		(40,641)
Income tax expense (benefit)	2,803	230	(3,238) (d)	4,994 (d)	(2,989) (d)		1,800
Net income (loss)	(21,068)	(502,964)	529,993	(42,050)	(6,352)		(42,441)
Undeclared preferred stock dividend	(18,248)	n/a	(3,585) (e)	—		21,833 (n)	—
Net income (loss) available to common stockholders	$ (39,316)	(502,964)	$ 526,408	$ (42,050)	$ (6,352)	$ 21,833	$ (42,441)
Net income (loss) per share of common stock:							
Basic	$ (0.98)	n/a					$ (0.49)
Diluted	$ (0.98)	n/a					(0.49)
Weighted average common shares outstanding:							
Basic	40,000 (o)					46,333 (l)(m)	86,333
Diluted	40,000 (o)					46,333 (l)(m)	86,333

NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL INFORMATION

1. Basis of Presentation

The accompanying unaudited pro forma condensed consolidated statements of operations and explanatory notes present the financial information of Berry Corp. assuming the events and transactions had occurred on January 1, 2017.

The following are descriptions of the columns included in the accompanying unaudited pro forma condensed consolidated statements of operations:

Predecessor represents the historical statements of operations of Berry LLC for the two months ended February 28, 2017.

Successor represents the historical consolidated statements of operations of Berry Corp. for the ten months ended December 31, 2017 and the nine months ended September 30, 2018, as applicable.

Plan of Reorganization and Fresh-Start Accounting Adjustments represent adjustments to give effect to the Plan and fresh-start accounting to the condensed consolidated statements of operations as of the date assumed.

Hugoton Disposition Adjustments represent adjustments to give effect to the disposition of the Company's interests in the Hugoton basin natural gas fields to the condensed consolidated statements of operations as of the date assumed.

Issuance of 2026 Notes Adjustments represent adjustments to give effect to the Company's issuance and net proceeds of the 2026 Notes to the condensed consolidated statements of operations as of the date assumed.

Series A Preferred Stock Conversion and Common Stock Offering Adjustments represent adjustments to give effect to the conversion of preferred stock into common stock, including the payment of cash dividends and the common stock offering to the condensed consolidated financial statements as of the date assumed.

2. Unaudited Pro Forma Condensed Consolidated Statement of Operations Adjustments

Plan of Reorganization and Fresh-Start Accounting Adjustments

The adjustments included in the unaudited pro forma condensed consolidated statements of operations above reflect the effects of the transactions contemplated by the Plan and executed by the Company on the Effective Date as well as fair value and other required accounting adjustments resulting from the adoption of fresh-start accounting.

(a) Reflects a reduction of depreciation, depletion and amortization expense based on new asset values and useful lives as a result of adopting fresh-start accounting as of the Effective Date.

BERRY PETROLEUM CORPORATION
NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED
FINANCIAL INFORMATION (Continued)

(b) As of the Effective Date, borrowings under the Emergence Credit Facility of $400 million were outstanding, which had an interest rate of 4.81% per annum, letter of credit fees accruing at a rate of 3.75% per annum on the amount subject to draw and a 0.50% per annum commitment fee on undrawn amounts. In addition, issuance costs were being amortized over the five-year term of the Emergence Credit Facility. The Company calculated the pro forma adjustment to decrease interest expense as follows for the two months ended February 28, 2017:

	($ in thousands)
Reversal of Pre-Emergence Credit Facility interest expense	$ 7,789
Reversal of amortization of issuance costs on Pre-Emergence Credit Facility	416
Reversal of other interest expense	40
Pro Forma - Emergence Credit Facility interest expense on drawn amounts	(3,153)
Pro Forma - Emergence Credit Facility commitment fee on undrawn amounts	(118)
Pro Forma - Emergence Credit Facility letter of credit fees	(39)
Pro Forma - Amortization of issuance costs on the Emergence Credit Facility	(5)
Pro Forma adjustment to decrease interest expense for the two months ended February 28, 2017	$ 4,930

(c) Represents the elimination of reorganization items that were directly attributable to the Chapter 11 reorganization and nonrecurring costs directly related to the bankruptcy, which consist of the following for the two months ended February 28, 2017:

	($ in thousands)
Gain on settlement of liabilities subject to compromise	$ (421,774)
Fresh-start valuation adjustments	920,699
Legal and other professional advisory fees	19,481
Other	(10,686)
Pro Forma adjustment to eliminate reorganization items for the two months ended February 28, 2017	$ 507,720

In connection with our emergence from bankruptcy, we terminated or renegotiated more favorable terms for several firm transportation and oil sales contracts.

(d) Upon emergence from bankruptcy, Berry Corp. acquired the assets of Berry LLC, which had been treated as a disregarded entity for federal and state income taxes, in a taxable asset acquisition as part of the restructuring. For the two-month period ended February 28, 2017, any tax benefit that would potentially be realizable as a result of the new tax status and losses incurred during the year has not been recognized under the assumption that the Company would not meet the “more likely than not” criteria under Accounting Standards Codification 740 “Income Taxes” and therefore would require a full valuation allowance.

For the year ended December 31, 2017, the effective tax rate used to calculate income tax expense was approximately (4)%. The effective tax rate differed from the federal statutory rate of 35% due to the impact of state taxes, the change in the valuation allowance and the tax reform rate change.

(e) Reflects the undeclared and accreted dividends on the Series A Preferred Stock assuming that we emerged from bankruptcy and the Series A Preferred Stock was issued on January 1, 2017 rather than the Effective Date.

Hugoton Disposition Adjustments

(f) Reflects the elimination of oil, natural gas, NGL and helium gas sales related to the Hugoton Disposition properties.

(g) Reflects the adjustments related to lease operating, transportation, taxes, other than income taxes, and general and administrative expenses related to the Hugoton Disposition properties.

(h) Reflects the elimination of estimated depreciation, depletion and amortization as well as accretion expense related to the Hugoton Disposition properties.

(i) Reflects the elimination of the gain on sale of assets related to the Hugoton Disposition.

Issuance of 2026 Notes Adjustments

(j) The issuance of the 2026 Notes was assumed to have occurred on January 1, 2017 for pro forma purposes and to have resulted in net proceeds of $391 million. As a result, borrowings under the RBL Facility would not have been necessary during this period.

The Company calculated the pro forma adjustment to increase interest expense as a result of the higher interest rate on the 2026 Notes for the year ended December 31, 2017 as follows:

	($ in thousands)	
Reversal of interest expense on Emergence Credit Facility net of availability fee	$	(19,769)
Pro Forma - 2026 Notes interest expense		28,000
Pro Forma - amortization of deferred financing costs on 2026 Notes		1,110
Pro Forma adjustment to increase interest expense in 2017	$	9,341

The Company calculated the pro forma adjustment to increase interest expense as a result of the higher interest rate on the 2026 Notes and reversing the interest expense and other fees associated with the RBL Facility for the nine months ended September 30, 2018 as follows:

	($ in thousands)	
Reversal of interest expense on Emergence Credit Facility, net of availability fee	$	(2,930)
Reversal of 2026 Notes interest expense		(18,073)
Reversal of 2026 Notes amortization of debt issuance cost		(735)
Pro Forma - 2026 Notes interest expense		21,000
Pro Forma - amortized portion of deferred financing costs on 2026 Notes		860
Pro Forma adjustment to increase interest expense	$	122

(k) The effective tax rate applied to the increased interest expense was 17% for the nine months ended September 30, 2018. The effective tax rate differed from the statutory tax rate of approximately 29% due to the impact of the change in the valuation allowance.

Series A Preferred Stock Conversion and Common Stock Offering Adjustments

(l) Adjustment includes the impact on basic and diluted weighted average common shares outstanding assuming the issuance of approximately 8.7 million additional shares of common stock in the IPO, net of the simultaneous purchase and sale of approximately 1.8 million shares of our common stock for the benefit of funds affiliated with Benefit Street Partners and Oaktree Capital Management, had occurred on January 1, 2017. For the year ended December 31, 2017 the impact was approximately 8.7 million additional common shares while the impact on the weighted average shares for the nine months ended September 30, 2018 was approximately 6.6 million additional common shares, as the IPO actually occurred in July 2018.

BERRY PETROLEUM CORPORATION
NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL INFORMATION (Continued)

(m) Adjustment includes the impact on basic and diluted weighted average common shares outstanding assuming the Series A Preferred Stock Conversion occurred on January 1, 2017. This assumes the April 2018 Series A Preferred Stock PIK dividend did not occur and approximately 35.8 million shares of Series A Preferred Stock were converted, at the conversion rate of 1 share of Series A Preferred Stock to 1.05 shares of common stock, into approximately 37.7 million shares of common stock on January 1, 2017. For the year ended December 31, 2017, the impact was approximately 37.7 million additional common shares while the impact on the weighted average shares for the nine months ended September 30, 2018 was approximately 27.9 million additional common shares as the Series A Preferred Stock Conversion actually occurred July 2018. Additionally, as a result of the pro forma adjustments noted in footnote (n) below, previously antidilutive stock awards would be dilutive on a proforma basis for the nine months ended September 30, 2018 resulting in approximately 0.2 million additional common shares included in the diluted weighted average common shares outstanding adjustment for this same period.

(n) Adjustment reflects the impact on Series A preferred stock dividends and conversion to common assuming the July 2018 Series A Preferred Stock Conversion occurred on January 1, 2017. This adjustment includes the effect of reversing the Series A Preferred Stock dividends for the year ended December 31, 2017 and nine months ended September 30, 2018. Additionally for the nine months ended September 30, 2018, this adjustment includes the effect of reversing the cash payment of approximately $60 million to holders of Series A Preferred Stock and approximately $27 million of value of the 1.9 million common shares (the aggregate conversion premium of 0.05 common share per 1 share of Series A Preferred Stock outstanding), received by preferred stockholders in conjunction with the July 2018 Series A Preferred Stock Conversion.

(o) Share count includes 7 million shares reserved for issuance to the general unsecured creditors resulting from the bankruptcy process.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are described under the heading "Risk Factors" included elsewhere in this prospectus. Please see "Cautionary Note Regarding Forward-Looking Statements." When we use the terms "we," "us," "our," the "Company," or similar words in this prospectus, unless the context otherwise requires, on or prior to the Effective Date, we are referring to Berry LLC, our predecessor company, and following the Effective Date, we are referring to Berry Corp. and its subsidiary, Berry LLC, together, the successor company, as applicable.

Our Company

We are a California-based independent upstream energy company engaged primarily in the development and production of conventional oil reserves located onshore in the western United States. Our long-lived, predictable and high margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive free cash flow through commodity price cycles. We believe that executing our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient production growth as well as the ability to return excess free cash flow to stockholders.

We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and the Uinta basin of Utah, and, to a lesser extent, the low geologic risk natural gas resource play in the Piceance basin in Colorado. In the aggregate, the Company's assets are characterized by:

- high oil content, which makes up more than 80% of our production;
- favorable Brent-influenced crude oil pricing dynamics;
- long-lived reserves with low and predictable production decline rates;
- stable and predictable development and production cost structures;
- a large inventory of low-risk identified development drilling opportunities with attractive full-cycle economics; and
- potential in-basin organic and strategic opportunities to expand our existing inventory with new locations of substantially similar geology and economics.

California is and has been one of the most productive oil and natural gas regions in the world. Our asset base is concentrated in the oil-rich San Joaquin basin in California, which has more than 100 years of production history and substantial remaining oil in place. As a result of these attributes, we have a strong understanding of many of the basin's geologic and reservoir characteristics, leading to predictable, repeatable, low-risk development opportunities.

In California, we focus on conventional, shallow reservoirs, the drilling and completion of which are relatively low-cost in contrast to modern unconventional resource plays. Our decades-old proven completion techniques in these reservoirs include steamflood and low-volume fracture stimulation. For example, we estimate the cost for PUD wells drilled and completed in California will average less than $450,000 per well. In contrast, we estimate the cost of PUD wells drilled and completed in the Piceance basin will average $1.8 million per well. Using SEC Pricing as of December 31, 2017, there were approximately 80 gross PUD locations associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.

We own additional assets in the Uinta basin in Utah, a stacked, multi-bench, light-oil-prone play with significant undeveloped resources where we have high operational control and additional behind pipe potential and in the Piceance basin in Colorado, a prolific low geologic risk natural gas play where we produce from a conventional, tight sandstone reservoir using proven slick water fracture stimulation techniques to increase recoveries. On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Using SEC Pricing as of December 31, 2017, we had estimated total proved reserves of 141,384 MBoe. For the three months ended September 30, 2018, we had average production of approximately 27.4 MBoe/d, of which approximately 81% was oil. In California, our average production for the three months ended September 30, 2018 was 19.5 MBoe/d, of which approximately 100% was oil.

How We Plan and Evaluate Operations

We use Levered Free Cash Flow to plan our capital allocation for maintenance and internal growth opportunities as well as hedging needs. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) operating expenses; (c) environmental, health & safety (“EH&S”) results; (d) taxes, other than income taxes; (e) general and administrative expenses; and (f) production.

Adjusted EBITDA

Adjusted EBITDA is the primary financial and operating measurement that our management uses to analyze and monitor the operating performance of our business. We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, amortization and accretion; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items.

Operating expenses

We define operating expenses as lease operating expenses, electricity expenses, transportation expenses, and marketing expenses, offset by the third-party revenues generated by electricity, transportation and marketing activities, as well as the effect of cash received or paid for gas purchase derivatives. Taxes other than income taxes are excluded from operating expenses. The electricity, transportation and marketing activity related revenues are viewed and treated internally as a reduction to operating costs when tracking and analyzing the economics of development projects and the efficiency of our hydrocarbon recovery. Overall, operating expense is used by management as a measure of the efficiency with which operations are performing.

Environmental, health & safety

We are committed to good corporate citizenship in our communities, operating safely and protecting the environment and our employees. We monitor our EH&S performance through various measures, holding our employees and contractors to high standards. Meeting corporate EH&S metrics is a part of our incentive programs for all employees.

Taxes, other than income taxes

Taxes, other than income taxes includes severance taxes, ad valorem and property taxes, GHG allowances, and other taxes not based on income. We include these taxes when analyzing the economics of development projects and the efficiency of our hydrocarbon recovery; however, we do not include these taxes in our operating expenses.

General and administrative expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

Production

Oil and gas production is a key driver of our operating performance, an important factor to the success of our business, and used in forecasting future development economics. We measure and closely monitor production on a continuous basis, adjusting our property development efforts in accordance with the results. We track production by commodity type and compare it to prior periods and expected results.

Emergence from Chapter 11 Bankruptcy

On February 28, 2017, Berry LLC emerged from bankruptcy as a stand-alone company and wholly-owned subsidiary of Berry Corp. with new management, a new board of directors and new ownership. Through the Chapter 11 Proceedings, the Company significantly improved its financial position from that of Berry LLC while it was owned by the Linn Entities. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters.

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Basis of Presentation and Fresh-Start Accounting

Upon Berry LLC's emergence from bankruptcy, we adopted fresh-start accounting, which, with the recapitalization upon emergence from bankruptcy, resulted in Berry Corp. becoming the financial reporting entity in our corporate group.

Unless otherwise noted or suggested by context, all financial information and data and accompanying financial statements and corresponding notes, as contained in this prospectus, on or prior to the Effective Date, reflect the actual historical results of operations and financial condition of our predecessor company for the periods presented and do not give effect to the Plan or any of the transactions contemplated thereby or the adoption of fresh-start accounting. Following the Effective Date, they reflect the actual historical results of operations and financial condition of Berry Corp. on a consolidated basis and give effect to the Plan and any of the transactions contemplated thereby and the adoption of fresh-start accounting. Thus, the financial information presented herein on or prior to the Effective Date is not comparable to Berry Corp.'s performance or financial condition after the Effective Date. As a result, "black-line" financial statements are presented to distinguish between Berry LLC as the predecessor and Berry Corp. as the successor.

Berry Corp.'s financial statements reflect the application of fresh-start accounting under GAAP. GAAP requires that the financial statements, for periods subsequent to the Chapter 11 Proceedings, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, gains and losses that are realized or incurred in the bankruptcy proceedings are recorded in "reorganization items, net" on Berry Corp.'s as well as Berry LLC's statements of operations. In addition, Berry Corp.'s balance sheet classifies the cash distributions from the Cash Distribution Pool as "liabilities subject to compromise." Pre-petition unsecured and under-secured obligations that were affected by the bankruptcy reorganization process have been classified as "liabilities subject to compromise" on our balance sheet and our predecessor company's balance sheet at December 31, 2016.

Reorganization and Financing Activities

The main actions we took affecting comparability between periods presented include the reorganization of Berry LLC through bankruptcy and resulting substantial elimination of debt, entry into the RBL Facility, issuance of the 2026

Notes, dividends on and conversion of Series A Preferred Stock and completion of the IPO. These actions are described above under "Emergence from Chapter 11 Bankruptcy" and below in "Liquidity and Capital Resources."

Capital Expenditures and Capital Budget

For the years ended December 31, 2017 and 2016, our capital expenditures were approximately $73 million and $26 million, respectively, on an accrual basis excluding acquisitions. For the three and nine months ended September 30, 2018, our capital expenditures were approximately $40 million and $95 million, respectively, on an accrual basis excluding acquisitions. Prior to the Effective Date, our predecessor company had financed its drilling and development program primarily through internally generated net cash provided by operating activities and funding from Linn Energy. Following commencement of the Chapter 11 Proceedings, our predecessor company halted substantially all of its planned capital expenditures until the Effective Date.

Following Berry LLC's emergence from bankruptcy and separation from the Linn Entities, we increased our pace of development and have continued to do so in 2018. Our 2018 anticipated capital expenditure budget of approximately $140 to $160 million represents an increase of approximately 107% over our 2017 capital expenditures, including the successor and predecessor periods, of approximately $73 million. Our 2019 anticipated capital expenditure budget is approximately $230 to $260 million. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2018 and 2019 capital programs while producing positive Levered Free Cash Flow. We expect to:

- employ:
  - three drilling rigs in California for the remainder of 2018;
  - one additional drilling rig assigned to drilling opportunities in Utah in the fourth quarter of 2018 and an average of four rigs in California in 2019; and
- drill approximately 230 to 250 gross development wells in 2018, of which we expect at least 235 will be in California, and 400 to 450 gross development wells in 2019, almost all of which we expect will be in California.

The table below sets forth the expected allocation of our 2018 capital expenditure budget by area as compared to the allocation of our 2017 capital expenditures.

	Capital Expenditure by Area	
	2018 Budget	2017 Actual
	(in millions)	
California	$ 122-136	$ 71
Uinta	12-16	1
Piceance	1-2	1
East Texas(1)	—	—
Corporate	5-6	—
Total	$ 140-160	$ 73

(1) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility 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, natural gas and NGLs, 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 interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and materially affect our business, financial condition and results of operations.

Chevron North Midway-Sunset Acquisition

In April 2018, we acquired two leases from a third party on an aggregate of 214 acres and a lease option on 490 acres of land owned by Chevron U.S.A. in the north Midway-Sunset field immediately adjacent to assets we currently operate. We assumed a drilling commitment of approximately $34.5 million to drill 115 wells on or before April 1, 2020. We had not drilled any of these wells as of September 30, 2018. We extended the commitment to April 1, 2022. We would assume an additional 40 well drilling commitment if we exercise our option on the 490 acres.We paid no other consideration for the acquisition. Our drilling commitment will be tolled for a month for each consecutive 30-day period for which the posted price of WTI is less than $45 per barrel. Our 2018 anticipated capital expenditure budget does not currently include funding for drilling wells against the assumed drilling commitment, but we have designated funds for drilling appraisal wells to determine whether to exercise the option. This transaction is consistent with our business strategy to investigate areas beyond our known productive areas. See “Prospectus Summary—Our Business Strategy—Maximize ultimate hydrocarbon recovery from our assets by optimizing drilling, completion and production techniques and investigating deeper reservoirs and areas beyond our known productive areas.”

Disposition of East Texas Properties

On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin for approximately $7 million, before purchase price adjustments. Production comprised approximately 0.7 MBoe per day of natural gas in the third quarter of 2018.

Commodity Derivatives

We utilize derivatives, such as swaps, puts and calls, to hedge a portion of our forecasted production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices. We target covering our operating expenses and fixed charges, including maintenance capital expenditures, for up to two years out. We have also hedged a portion of our exposure to differentials between Brent and WTI. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations that we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

Our current hedge positions primarily consist of swap contracts and deferred premium purchased put options. We also recently acquired natural gas fixed price swaps to hedge our exposure to price changes for natural gas purchases. We enter into these transactions with respect to a portion of our projected oil production and gas purchases to provide economic hedges against the risk related to the future commodity prices. We do not enter into derivative contracts for speculative trading purposes.

Swap contracts are designed to provide a fixed price. For fixed-price swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For oil basis swaps, we make settlement payments if the difference between Brent and WTI is greater than the indicated weighted-average price per barrel and receive settlement payments if the difference between Brent and WTI is below the indicated weighted-average price per barrel. We earn a premium on our sold oil calls at the time of sale. We make net settlement payments for prices above the indicated weighted-average price per barrel of Brent. If the calls expire unexercised, no payments are received. For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For fixed-price natural gas swaps, we are the buyer so we make settlement payments for prices below the weighted-average price per MMBtu and receive settlement payments for prices above the weighted-average price per MMBtu.

As of September 30, 2018, we have hedged crude oil production at the following approximate volumes and prices: 12.8 MBbl/d at $75 per barrel in the fourth quarter of 2018, 16.5 MBbl/d at $70 per barrel in 2019, and 1.2 MBbl/d at $65 per barrel in 2020, as outlined along with our natural gas derivative contracts in the following table:

	2018	2019	2020
Sold Oil Calls (ICE Brent):			
Hedged volume (MBbls)	124	—	—
Weighted-average price ($/Bbl)	$ 80.00	$ —	$ —
Purchased put options (ICE Brent):			
Hedged volume (MBbls)	—	3,385	455
Weighted-average price ($/Bbl)	$ —	$ 65.00	$ 65.00
Fixed Price Swaps (ICE Brent)			
Hedged volume (MBbls)	1,058	2,640	—
Weighted-average price ($/Bbl)	$ 74.82	$ 75.40	$ —
Oil basis differential positions:			
ICE Brent - NYMEX WTI basis swaps			
Hedged volume (MBbls)	92	182.5	—
Weighted-average price ($/Bbl)	$ 1.29	$ 1.29	$ —
Fixed Price Swaps (Kern):			
Hedged volume (MMBtu)	1,380,000	4,560,000	—
Weighted-average price ($/MMBtu)	2.65	2.65	—

The following table summarizes the historical results of our hedging activities.

	Berry Corp. (Successor)						Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Crude Oil (per Bbl):								
Realized price, before the effects of derivative settlements	$ 67.67	$ 67.93	$ 45.50	$ 65.97	$ 48.05	$ 44.87	$ 46.94	$ 35.83
Effects of derivative settlements	$ (0.44)	$ (14.71)	$ 2.07	$ (8.01)	$ 0.48	$ 2.30	$ 0.46	$ 1.05

We expect our operations to generate substantial cash flows at current commodity prices. We have protected a portion of our anticipated cash flows through 2020 as part of our crude oil hedging program. Our low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production.

In May 2018, we elected to terminate outstanding commodity derivative contracts for all WTI oil swaps and certain WTI/Brent basis swaps for July 2018 through December 2019 and all WTI oil sold call options for July 2018 through June 2020. Termination costs totaled approximately $127 million and were calculated in accordance with a bilateral agreement on the cost of elective termination included in these derivative contracts; the present value of the contracts using the forward price curve as of the date termination was elected. No penalties were charged as a result of the elective termination. Concurrently, Berry Corp. entered into commodity derivative contracts consisting of Brent oil swaps for July 2018 through March 2019 and Brent oil purchased put options for January 2019 through March 2020. These Brent oil swaps hedge 1.8 MMBbls in 2018 and 0.9 MMBbls in 2019 at a weighted-average price of $75.66. These Brent oil purchased put options provide a weighted-average price floor of $65.00 for 2.8 MMBbls in 2019 and 0.5 MMBbls in 2020. We effected these transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with current market pricing.

Income Taxes

Prior to the Effective Date, Berry LLC was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, Berry LLC was not a taxable entity, it did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of Berry LLC. Upon emergence from bankruptcy, Berry Corp. acquired the assets of Berry LLC in a taxable asset acquisition as part of the restructuring. Consequently, we are now taxed as a corporation and have no net operating loss carryforwards for the periods prior to February 28, 2017.

On December 22, 2017, the U.S. enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (the “Act”) which made significant changes to the Internal Revenue Code of 1986 (the "Code"), including lowering the maximum federal corporate rate from 35% to 21% and imposing limitations on the use of net operating losses arising in taxable years ending after December 31, 2017. This was the key contributor to the decrease in our effective rate from 40% in the 2017 Successor periods to 17% in each of the three and nine months ended September 30, 2018, respectively. We anticipate earnings for fiscal year 2018, in part due to the termination and resetting of our hedge positions in May 2018. These earnings consequently allow for the release of our valuation allowance, resulting in an effective tax rate less than the maximum federal and applicable state tax rate for the nine months ended September 30, 2018. There were no current income taxes during the nine months ended September 30, 2018.

Our accounting for the Act is incomplete. As noted at year-end, however, we were able to reasonably estimate certain effects and, therefore, recorded provisional adjustments to income tax expense for the revaluation of deferred tax assets and liabilities from 35% to 21% associated with the reduction in the U.S. corporate income tax rate, and for a valuation allowance on certain deferred tax assets impacted by the Act. We have not revised any of the 2017 provisional estimates. Any subsequent adjustments to these amounts will be recorded to income tax expense in the fourth quarter of 2018 after analysis of the filed 2017 income tax return is complete.

Business Environment and Market Conditions

The oil and gas industry is heavily influenced by commodity prices. Since the latter half of 2014, commodity prices have declined and remained at relatively low levels through the middle of 2017 but have generally risen since then. For example, the Brent crude oil futures contract prices declined from a high of over $108.19 per Bbl in July 2014 to a low of $31.93 per Bbl in January 2016. The HH spot price for natural gas has also declined since 2014, though reduced gas prices are a net benefit to our results of operations. While oil prices remain lower than the 2014 averages, they have improved since early 2016. Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Please see “Risk Factors—Risks Related to Our Business and Industry—Oil, natural gas and NGL prices are volatile and directly affect our results.”

The following table presents the average ICE Brent, NYMEX WTI oil and NYMEX HH natural gas prices for the three months ended September 30, 2018, June 30, 2018, and September 30, 2017, the nine months ended September 30, 2018, the seven months ended September 30, 2017 and the two months ended February 28, 2017 and the years ended December 31, 2017 and 2016:

	Berry Corp. (Successor)						Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Year Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
ICE (Brent) oil ($/Bbl)	$ 75.93	$ 74.87	$ 52.21	$ 72.67	$ 54.82	$ 51.70	$ 55.72	$ 45.00
NYMEX (WTI) oil ($/Bbl)	$ 69.50	$ 67.76	$ 48.20	$ 66.75	$ 50.95	$ 48.45	$ 53.04	$ 43.32
NYMEX (HH) natural gas ($MMBtu)	$ 2.90	$ 2.80	$ 3.00	$ 2.90	$ 3.11	$ 3.03	$ 3.66	$ 2.46

Oil prices and differentials will continue to be affected by a variety of factors, including worldwide and regional economic conditions, transportation costs, imports, political conditions in producing regions, exploration levels, inventory levels, the actions of the OPEC and other state-controlled oil companies and significant producers, local pricing, gathering facility and transportation dynamics, exploration, development, production and transportation costs, the effects of conservation, weather, geophysical and technology, refining and processing disruptions, exchange rates, taxes and regulations and other matters affecting the supply and demand dynamics for oil, technological advances, regional market conditions, transportation capacity and costs in producing areas and the effect of changes in these variables on market perceptions.

California oil prices are Brent-influenced as California refiners import more than 50% of the state’s demand from foreign sources. There is a closer correlation of prices in California to Brent pricing than to WTI. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, will allow us to continue to realize strong cash margins in California.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for oil's unique characteristics and the remoteness of the assets makes access to other markets logistically challenging.

Prices and differentials for NGLs are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products for which they are used as feedstock. In addition, infrastructure constraints magnify pricing volatility.

Natural gas prices and differentials are strongly affected by local market fundamentals, as well as availability of transportation capacity from producing areas. Higher natural gas prices have a net negative effect on our operating results. We use substantially more natural gas for our steamfloods and power generation, than we produce and sell. The negative impact of higher prices on our operating costs is, however, partially offset by higher natural gas sales.

Our earnings are also affected by the performance of our cogeneration facilities. These cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce operating expenses, we also sell electricity produced by three of our cogeneration facilities under long-term contracts. The most significant input and cost of the cogeneration facilities is natural gas. The price we receive from selling electricity to third–parties is closely tied to the price of natural gas and thus these operations effectively serve as a partial hedge against gas price increases.

Production, Prices and Costs

The following table sets forth information regarding total production, average daily production, average prices and average costs for each of the periods indicated.

	Berry Corp. (Successor)				
	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended September 30, 2017	Variance Q3 2018 vs. Q2 2018	Variance Q3 2018 vs. Q3 2017
Average daily production[(1)]:					
Oil (MBbl/d)	22.3	21.1	21.2	1.2	1.1
Natural Gas (MMcf/d)	27.4	28.0	36.6	(0.6)	(9.2)
NGL (MBbl/d)	0.5	0.7	1.9	(0.2)	(1.4)
Total (MBoe/d)[(2)]	27.4	26.5	29.2	0.9	(1.8)
Total Production[(1)]:					
Oil (MBbl)	2,049	1,920	1,950	129	99
Natural gas (MMcf)	2,523	2,551	3,364	(28)	(841)
NGLs (MBbl)	49	62	173	(13)	(124)
Total combined production (MBoe)[(2)]	2,520	2,407	2,684	112	(164)
Weighted average realized prices:					
Oil with hedges (Bbl)	$ 67.23	$ 53.22	$ 47.57	$ 14.01	$ 19.66
Oil without hedges (Bbl)	$ 67.67	$ 67.93	$ 45.50	$ (0.26)	$ 22.17
Natural gas (Mcf)	$ 2.55	$ 2.12	$ 2.76	$ 0.43	$ (0.21)
NGL (Bbl)	$ 37.75	$ 24.38	$ 21.74	$ 13.37	$ 16.01
Average Benchmark prices:					
Oil (Bbl) – Brent	$ 75.93	$ 74.87	$ 52.21	$ 1.06	$ 23.72
Oil (Bbl) – WTI	$ 69.50	$ 67.76	$ 48.20	$ 1.74	$ 21.30
Natural gas (MMBtu) – HH	$ 2.90	$ 2.80	$ 3.00	$ 0.10	$ (0.10)
Average costs per Boe[(3)]:					
Lease operating expenses	$ 20.50	$ 17.24	$ 17.22	$ 3.26	$ 3.28
Electricity generation expenses	2.43	1.30	1.71	1.13	0.72
Electricity sales[(3)]	(5.66)	(2.48)	(3.32)	(3.18)	(2.34)
Transportation expenses	0.92	0.97	2.08	(0.05)	(1.16)
Transportation sales[(3)]	(0.07)	(0.09)	—	0.02	(0.07)
Marketing expenses	0.17	0.17	0.25	—	(0.08)
Marketing revenues[(3)]	(0.19)	(0.22)	(0.30)	0.03	0.11
Total operating expenses	$ 18.10	16.89	$ 17.64	$ 1.21	$ 0.46
General and administrative expenses[(4)]	$ 5.33	$ 5.18	$ 4.37	$ 0.15	$ 0.96
Depreciation, depletion and amortization	$ 8.62	$ 9.08	$ 7.76	$ (0.46)	$ 0.86
Taxes, other than income taxes	$ 3.30	$ 3.62	$ 4.39	$ (0.32)	$ (1.09)

(1) Production represents volumes sold during the period.
(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.
(3) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics

of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales, reported in "Other Revenues", primarily relate to water and other liquids that we transport on our systems on behalf of third parties.

(4) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of approximately $1.08, $1.24 and $1.45 per Boe for the three months ended September 30, 2018, June 30, 2018 and September 30, 2017, respectively.

The following table sets forth average daily production by operating area for the periods indicated:

	Berry Corp. (Successor)				Berry LLC (Predecessor)	
	Three Months Ended September 30, 2018	**Three Months Ended June 30, 2018**	**Ten Months Ended December 31, 2017**	**Three Months Ended September 30, 2017**	**Two Months Ended February 28, 2017**	**Year Ended December 31, 2016**
Average daily production (MBoe/d)[1]:						
California[2]	19.5	18.8	18.0	18.8	17.0	20.2
Hugoton basin[3]	—	—	4.5	3.2	10.8	9.5
Uinta basin	5.1	5.3	5.3	5.0	5.4	5.8
Piceance basin	2.0	1.6	2.0	1.1	2.3	2.9
East Texas[4]	0.7	0.8	1.1	1.1	1.1	1.3
Total average daily production	27.4	26.5	30.9	29.2	36.7	39.7

(1) Production represents volumes sold during the period.
(2) On July 31, 2017, we purchased the remaining approximately 84% working interest of our South Belridge Hill property, located in Kern County, California.
(3) On July 31, 2017, we sold our 78% working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle. Our Hugoton assets represented approximately 24% of our average net daily production for the year ended December 31, 2016.
(4) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Average daily production volumes increased for the three months ended September 30, 2018 compared to the three months ended June 30, 2018 due to increased development capital spending in late 2017 and 2018 and the resumption of normal operations in Utah after the alleviation of market disruptions caused by a refinery fire earlier in 2018. Excluding the impact of the oil inventory and sales activities, oil production increased more than 3% quarter over quarter. In addition, our September 2018 monthly production rate of 28.2 MBoe/d reflects an increase of approximately 5% over our June 2018 monthly production rate of 26.8 MBoe/d.

Average daily production volumes decreased 6% to approximately 27.4 MBoe/d for the three months ended September 30, 2018 from approximately 29.2 MBoe/d for the three months ended September 30, 2017. The decrease primarily reflected the decreased natural gas and NGL volumes from the Hugoton Disposition in July 2017, partially offset by the additional oil volumes from the Hill Acquisition in July 2017. Partially offsetting this overall Boe decrease was an increase in oil production, mainly in California, as a result of our increased capital spending and development program in 2018 compared to 2017, and to a lesser degree, the sales of oil inventory in the quarter ended September 30, 2018. The Hill Acquisition and Hugoton Disposition resulted in a relative increase in oil production to 81% of total production in the three months ended September 30, 2018 from 73% of total production for the three months ended September 30, 2017.

The following tables set forth information regarding total production, average daily production, average prices and average costs for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including the successor and predecessor periods. The information for the nine months ended September 30, 2017 is reflected in the tables and narrative discussion that follows in two distinct periods, the seven months ended September 30, 2017 and the two months ended February 28, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to the nine months ended September 30, 2017 are used to provide comparable periods. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods presented.

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
Average Daily Production[(1)]:			
Oil (MBbl/d)	21.5	20.0	19.5
Natural Gas (MMcf/d)	27.7	57.2	71.7
NGL (MBbl/d)	0.6	2.6	5.2
Total (MBoe/d)[(2)]	26.7	32.1	36.7
Total Production[(1)]:			
Oil (MBbl)	5,867	4,288	1,153
Natural gas (MMcf)	7,555	12,241	4,232
NGLs (MBbl)	157	552	304
Total combined production (MBoe)[(2)]	7,284	6,880	2,162
Weighted average realized prices:			
Oil with hedges (Bbl)	$ 57.96	$ 47.17	$ 47.40
Oil without hedges (Bbl)	$ 65.97	$ 44.87	$ 46.94
Natural gas (Mcf)	$ 2.44	$ 2.69	$ 3.42
NGL (Bbl)	$ 28.93	$ 21.67	$ 18.20
Average benchmark prices:			
Oil (Bbl) – Brent	$ 72.67	$ 51.70	$ 55.72
Oil (Bbl) – WTI	$ 66.75	$ 48.45	$ 53.04
Natural gas (MMBtu) – HH	$ 2.90	$ 3.03	$ 3.66
Average costs per Boe[(3)]:			
Lease operating expenses	$ 18.87	$ 15.26	$ 13.06
Electricity generation expenses	1.90	1.48	1.48
Electricity sales[(3)]	(3.53)	(2.26)	(1.69)
Transportation expenses	1.05	2.71	2.86
Transportation sales[(3)]	(0.07)	—	—
Marketing expenses	0.20	0.24	0.30
Marketing revenues[(3)]	(0.25)	(0.28)	(0.29)
Total operating expenses	$ 18.17	$ 17.15	$ 15.72
General and administrative expenses[(4)]	$ 5.20	$ 6.33	$ 3.68
Depreciation, depletion and amortization	$ 8.51	$ 7.03	$ 13.02
Taxes, other than income taxes	$ 3.47	$ 3.65	$ 2.41

(1) Production represents volumes sold during the period.
(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years.
(3) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to

generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales, reported in "Other Revenues", primarily relate to water and other liquids that we transport on our systems on behalf of third parties.

(4) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of approximately of approximately $1.22, $4.12 and none per Boe for the nine months ended September 30, 2018, the seven months ended September 30, 2017 and the two months ended February 28, 2017, respectively.

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
Average daily production (MBoe/d):[1]			
California (San Joaquin)	19.0	17.3	17.0
Hugoton basin[2]	—	6.5	10.8
Uinta basin	5.2	5.4	5.4
Piceance basin	1.7	1.9	2.4
East Texas[4]	0.8	1.0	1.1
Total average daily production	26.7	32.1	36.7

(1) Production represents volumes sold during the period.
(2) On July 31, 2017, we purchased the remaining approximately 84% working interest in our South Belridge Hill property, located in Kern County, California.
(3) On July 31, 2017, we sold our 78% working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle. Our Hugoton assets represented approximately 24% of our average net daily production for the year ended December 31, 2016.
(4) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Average daily production volumes decreased to approximately 26.7 MBoe/d for the nine months ended September 30, 2018 from approximately 33.1 MBoe/d for the nine months ended September 30, 2017, including the successor and predecessor periods. The decrease primarily reflected the decreased natural gas and NGL volumes from the Hugoton Disposition in July 2017, partially offset by the additional oil volumes from the Hill Acquisition. Partially offsetting the overall Boe decrease was an increase in oil production, mainly in California, as a result of our increased capital spending and development program in 2018 compared to 2017. The Hill Acquisition and Hugoton Disposition resulted in an increase in oil production to 81% of total production for the nine months ended September 30, 2018 from 60% for the nine months ended September 30, 2017.

The following tables set forth information regarding total production, average daily production, average prices and average costs for the year ended December 31, 2017, including the successor and predecessor periods, and the year ended December 31, 2016. The information for the year ended June 30, 2017 are reflected in the tables and narrative discussion that follows in two distinct periods, the ten months ended December 31, 2017 and the two months ended February 28, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to year ended December 31, 2017 are used to provide comparable periods. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods presented.

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Average daily production[(1)]:			
Oil (MBbl/d)	20.6	19.5	23.1
Natural Gas (MMcf/d)	49.4	71.7	78.1
NGL (MBbl/d)	2.0	5.2	3.6
Total (MBoe/d)[(2)]	30.9	36.7	39.7
Total Production:			
Oil (MBbl)	6,318	1,153	8,463
Natural gas (MMcf)	15,119	4,232	28,577
NGLs (MBbl)	605	304	1,307
Total combined production (MBoe)[(2)]	9,443	2,162	14,533
Weighted average realized prices:			
Oil with hedges (Bbl)	$ 48.53	$ 47.40	$ 36.88
Oil without hedges (Bbl)	$ 48.05	$ 46.94	$ 35.83
Natural gas (Mcf)	$ 2.70	$ 3.42	$ 2.31
NGL (Bbl)	$ 22.23	$ 18.20	$ 17.67
Average Benchmark prices:			
Oil (Bbl) – Brent	$ 54.65	$ 55.72	$ 45.00
Oil (Bbl) – WTI	$ 50.53	$ 53.04	$ 43.32
Natural gas (MMBtu) – HH	$ 3.00	$ 3.66	$ 2.46
Average costs per Boe[(3)]:			
Lease operating expenses	$ 15.84	$ 13.06	$ 12.73
Electricity generation expenses	1.58	1.48	1.18
Electricity sales[(3)]	(2.33)	(1.69)	(1.60)
Transportation expenses	2.04	2.86	2.86
Marketing expenses	0.25	0.30	0.21
Marketing revenues[(3)]	(0.29)	(0.29)	(0.25)
Total operating expenses	$ 17.09	$ 15.72	$ 15.13
General and administrative expenses[(4)]	$ 5.93	$ 3.68	$ 5.45
Depreciation, depletion and amortization	$ 7.25	$ 13.02	$ 12.26
Taxes, other than income taxes	$ 3.62	$ 2.41	$ 1.73

(1) Production represents volumes sold during the period.

(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years.

(3) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties.

(4) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of approximately $3.40 per Boe for the ten months ended December 31, 2017.

The following table sets forth average daily production by operating area for the periods indicated:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Average daily production (MBoe/d)[(1)]:			
California[(2)]	18.0	17.0	20.2
Hugoton basin[(3)]	4.5	10.8	9.5
Uinta basin	5.3	5.4	5.8
Piceance basin	2.0	2.3	2.9
East Texas[(4)]	1.1	1.1	1.3
	30.9	36.7	39.7

(1) Production represents volumes sold during the period.
(2) On July 31, 2017, we purchased the remaining approximately 84% working interest of our South Belridge Hill property, located in Kern County, California.
(3) On July 31, 2017, we sold our 78% working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle. Our Hugoton assets represented approximately 24% of our average net daily production for the year ended December 31, 2016.
(4) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Average daily production volumes decreased in 2017, including the successor ten months ended December 31, 2017 and the predecessor two months ended February 28, 2017, by 7.9 MBoe/d, or 20%, when compared to the year ended December 31, 2016, primarily due to reduced development capital spending in 2016 and early 2017 and the Hugoton Disposition in July 2017, partially offset by the additional oil volumes from the Hill Acquisition in July 2017.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2017 to September 30, 2018 are discussed below.

	Berry Corp. (Successor)	
	September 30, 2018	December 31, 2017
	(in thousands)	
Cash and cash equivalents	$ 23,856	$ 33,905
Accounts receivable, net	$ 65,757	$ 54,720
Restricted cash	$ 57	$ 34,833
Other current assets	$ 13,233	$ 14,066
Property, plant & equipment, net	$ 1,418,366	$ 1,387,191
Other noncurrent assets	$ 18,338	$ 21,687
Accounts payable and accrued liabilities	$ 117,801	$ 97,877
Derivative instruments - current and long-term	$ 31,073	$ 75,281
Liabilities subject to compromise	$ 57	$ 34,833
Long-term debt	$ 391,512	$ 379,000
Asset retirement obligation	$ 89,404	$ 94,509
Other noncurrent liabilities	$ 15,617	$ 3,704
Equity	$ 889,110	$ 859,310

See “Liquidity and Capital Resources” for discussions about the changes in cash and cash equivalents and long-term debt.

The $11 million increase in accounts receivable was driven by increased sales.

Restricted cash at September 30, 2018 and December 31, 2017 represented funds set aside to settle the general unsecured creditors' claims resulting from our bankruptcy process. The decrease in restricted cash, and the corresponding decrease in liabilities subject to compromise, represented the settlement of these claims, the return of undistributed funds of approximately $23 million and professional fees related to the settlement of these claims.

The $31 million increase in property, plant and equipment was largely the result of increased capital investments in oil and gas properties, partially offset by increased accumulated depreciation associated with such properties.

The $3 million decrease in other noncurrent assets was primarily driven by amortization of debt issuance costs.

The increase in accounts payable and accrued liabilities included a $9 million increase in the accruals for the increased capital spending in 2018, a $7 million increase in dividends payable, an almost $4 million increase from the new interest payment obligations on our 2026 Notes, issued in February of 2018, a $3 million increase in the current portion of the asset retirement obligation, and a $3 million increase in taxes other than income taxes, largely due to the timing of payments, partially offset by a $6 million decrease in the current portion of our greenhouse gas liability.

The decrease in the derivative liability reflected the early termination and replacement of certain hedge contracts to move from a WTI-based position to a Brent-based position and to align our hedging program with higher commodity prices.

The increase in long-term debt resulted from the issuance of our 2026 Notes in February 2018 in the principal amount of $400 million, net of deferred financing costs, which was used to pay down the $379 million balance on our RBL Facility.

The decrease in asset retirement obligation reflected 2018 revisions in estimate of $7 million and liabilities settled during the period of $3 million, offset by accretion expense of $5 million.

The increase in other noncurrent liabilities represented an additional greenhouse gas liability of $12 million for production during the nine months ended September 30, 2018 and which is due for payment more than one year from September 30, 2018.

The increase in equity reflected the receipt of IPO proceeds of $111 million and net income of $15 million, offset by approximately $60 million of distributions to the former preferred stock holders in connection with the conversion to common stock and $20 million repurchase from certain general unsecured creditors of the right to receive shares of our common stock in settlement of their claims as well as $11 million in preferred dividends and $7 million in common dividends.

Results of Operations

Results of Operations - Three Months Ended September 30, 2018 compared to Three Months Ended June 30, 2018

	Berry Corp. (Successor)			
	Three Months Ended			
	September 30, 2018	June 30, 2018	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 147,004	$ 137,385	$ 9,619	7 %
Electricity sales	14,268	5,971	8,297	139 %
Gain (losses) on oil derivatives	(18,994)	(78,143)	59,149	(76)%
Marketing and other revenues	669	769	(100)	(13)%
Total revenues and other	142,947	65,982	76,965	117 %
Expenses and other:				
Lease operating expenses	51,649	41,517	10,132	24 %
Electricity generation expenses	6,130	3,135	2,995	96 %
Transportation expenses	2,318	2,343	(25)	(1)%
Marketing expenses	437	407	30	7 %
General and administrative expenses	13,429	12,482	947	8 %
Depreciation, depletion, amortization and accretion	21,729	21,859	(130)	(1)%
Taxes, other than income taxes	8,317	8,715	(398)	(5)%
(Gains) losses on natural gas derivatives	(1,879)	—	(1,879)	— %
(Gains) losses on sale of assets and other, net	400	123	277	225 %
Total expenses and other	102,530	90,581	11,949	13 %
Other income (expenses):				
Interest expense	(9,877)	(9,155)	(722)	8 %
Other, net	347	(239)	586	(245)%
Reorganization items, net	13,781	456	13,325	2,922 %
Income (loss) before income taxes	44,668	(33,537)	78,205	(233)%
Income tax expense (benefit)	7,683	(5,476)	13,159	(240)%
Net income (loss)	36,985	(28,061)	65,046	(232)%
Series A preferred stock dividends and conversion to common stock	(86,642)	(5,650)	(80,992)	1,433 %
Net income (loss) available to common stockholders	$ (49,657)	$ (33,711)	$ (15,946)	47 %

Revenues and Other

Oil, natural gas and NGL sales increased nearly $10 million, or 7% to approximately $147 million for the three months ended September 30, 2018 compared to the three months ended June 30, 2018. The increase reflects an increase in oil sales, including the impact of selling Utah oil in inventory during the third quarter, with quarter over quarter realized oil prices that were essentially flat, as well as higher realized gas prices on slightly lower volumes.

Electricity sales represent sales to utilities and increased by approximately $8 million, or 139%, to approximately $14 million for the three months ended September 30, 2018, compared to the three months ended June 30, 2018. The increase was primarily due to higher summer rates, consistent with the significantly higher gas prices.

Losses on oil and natural gas derivatives were approximately $19 million for the three months ended September 30, 2018 compared to losses of approximately $78 million for the three months ended June 30, 2018. The improvement reflects the May 2018 transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with market pricing at the time.

Marketing revenues in these periods primarily represent sales of third-party natural gas and were comparable for the three months ended September 30, 2018 and June 30, 2018.

Expenses and other

We report sales of electricity, marketing and transportation activities (as applicable) separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing revenues and expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales, reported in "Other Revenues", primarily relate to water and other liquids that we transport on our systems on behalf of third parties. Additionally, at times we enter into derivatives to lock in the price of a portion of our gas purchases. The periodic cash settlement portion of these positions are included in our operating expenses.

Operating expenses, as defined above, increased to $18.10 per Boe for the quarter ended September 30, 2018 from $16.89 per Boe for the quarter ended June 30, 2018. The increase was primarily driven by an increase in lease operating expenses per Boe, partially offset by an increase in the gross margin for our electricity sales.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased by approximately $10 million, or 24%, to approximately $52 million for the three months ended September 30, 2018, compared to the three months ended June 30, 2018. The increase was primarily due to higher fuel prices, coupled with increased maintenance and chemical costs. For the same reasons, lease operating expenses per Boe increased to $20.50 per Boe for the three months ended September 30, 2018 from $17.24 per Boe for the three months ended June 30, 2018.

Electricity generation expenses increased by approximately $3 million or 96% for the three months ended September 30, 2018 compared to the three months ended June 30, 2018, primarily due to higher fuel prices.

Transportation and marketing expenses for the three months ended September 30, 2018 were both comparable to the three months ended June 30, 2018.

General and administrative expenses increased by approximately $1 million, or 8%, to approximately $13 million for the three months ended September 30, 2018 compared to the three months ended June 30, 2018. The increase in absolute dollars incurred resulted in slightly higher general and administrative expenses of $5.33 per Boe for the three months ended September 30, 2018, compared to $5.18 per Boe for the three months ended June 30, 2018. For the three months ended September 30, 2018 and June 30, 2018, general and administrative expenses included non-recurring restructuring and other costs of approximately $1.6 million and $1.7 million, respectively, and non-cash stock compensation costs of approximately $1.1 million and $1.3 million, respectively. Adjusted general and administrative expenses were $4.25 per Boe for the three months ended September 30, 2018 compared to $3.95 per Boe for the three months ended June 30, 2018. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the company's growth and public company status.

Depreciation, depletion and amortization ("DD&A") are comparable between the three months ended September 30, 2018 and the three months ended June 30, 2018.

Gains on natural gas derivatives of $2 million for the three months ended September 30, 2018 represent the mark-to-market valuation on derivative contracts entered into in the third quarter of 2018 that will begin to settle in the fourth quarter of 2018.

Taxes, Other Than Income Taxes

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	June 30, 2018	Variance
	(in thousands)		
Severance taxes	$ 2,149	$ 2,997	$ (848)
Ad valorem and property taxes	3,165	3,141	24
Greenhouse gas allowances	3,002	2,577	425
Total taxes other than income taxes	$ 8,317	$ 8,715	$ (398)

Taxes, other than income taxes decreased in the three months ended September 30, 2018 by $0.4 million or 5%, compared to the three months ended June 30, 2018 due to lower severance taxes, partially offset by higher costs of greenhouse gas allowances. The lower severance taxes in the third quarter were largely a result of higher second quarter costs from supplemental billings received that quarter which partially related to prior periods, as well as lower revenues, the basis for such taxes, in the third quarter in the jurisdictions where severance taxes apply. The higher greenhouse gas allowance costs in the third quarter were a result of fewer free allowances received for this period which increased the average unit cost of the incurred emissions compared to the second quarter.

Other income (expenses)

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	June 30, 2018	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$ (9,877)	$ (9,155)	$ (722)
Other, net	347	(239)	586
Total other income (expense)	$ (9,530)	$ (9,394)	$ (136)

Interest expense increased for the three months ended September 30, 2018 by 0.7 million or 8%, compared to the three months ended June 30, 2018, due to increased borrowings on the RBL Facility within the three months ended September 30, 2018 compared to the prior quarter for IPO, Series A preferred stock conversion, and hedge termination activities. Other, net during the three months ended September 30, 2018 includes interest income and collection of a prior period vendor rebate.

Reorganization items

The following table summarizes the components of reorganization items included in the statement of operations:

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	June 30, 2018	Variance
	(in thousands)		
Return of undistributed funds from Cash Distribution Pool	$ 13,799	$ —	$ 13,799
Legal and other professional advisory fees	(713)	(1,178)	465
Gain on resolution of pre-emergence liabilities	—	1,634	(1,634)
Linn Energy bankruptcy claim receipt	1,500	—	1,500
Other	(805)	—	(805)
Total reorganization items, net	$ 13,781	$ 456	$ 13,325

Reorganization items, net consisted of a gain of approximately $14 million for the three months ended September 30, 2018. The gain was primarily due to the return of undistributed funds from the general unsecured creditor pool, coupled with a bankruptcy claim receipt, partially offset by legal and other professional fees. For the three months ended June 30, 2018, the net gain of approximately $0.5 million was primarily due to the resolution of certain pre-emergence liabilities, partially offset by legal and other professional fees.

Income taxes

The three months ended September 30, 2018 had a $8 million tax expense compared to an income tax benefit of $5 million for the three months ended June 30, 2018. The effective tax rate was 17% for the three months ended September 30, 2018 and 16% for the three months ended June 30, 2018.

Results of Operations - Three Months Ended September 30, 2018 compared to Three Months Ended September 30, 2017.

	Berry Corp. (Successor)			
	Three Months Ended			
	September 30, 2018	September 30, 2017	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 147,004	$ 101,763	$ 45,241	44 %
Electricity sales	14,268	8,914	5,354	60 %
Gain (losses) on oil derivatives	(18,994)	(42,443)	23,449	(55)%
Marketing and other revenues	669	1,676	(1,007)	(60)%
Total revenues and other	142,947	69,910	73,037	104 %
Expenses and other:				
Lease operating expenses	51,649	46,224	5,425	12 %
Electricity generation expenses	6,130	4,580	1,550	34 %
Transportation expenses	2,318	5,586	(3,268)	(59)%
Marketing expenses	437	674	(237)	(35)%
General and administrative expenses	13,429	11,729	1,700	14 %
Depreciation, depletion, amortization and accretion	21,729	20,822	907	4 %
Taxes, other than income taxes	8,317	11,782	(3,465)	(29)%
(Gains) losses on natural gas derivatives	(1,879)	—	(1,879)	— %
(Gains) losses on sale of assets and other, net	400	(20,692)	21,092	(102)%
Total expenses and other	102,530	80,705	21,825	27 %
Other income (expenses):				
Interest expense	(9,877)	(5,882)	(3,995)	68 %
Other, net	347	1,155	(808)	(70)%
Reorganization items, net	13,781	(408)	14,189	(3,478)%
Income (loss) before income taxes	44,668	(15,930)	60,598	(380)%
Income tax expense (benefit)	7,683	(6,246)	13,929	(223)%
Net income (loss)	36,985	(9,684)	46,669	(482)%
Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(81,157)	1,480 %
Net income (loss) available to common stockholders	$ (49,657)	$ (15,169)	$ (34,488)	227 %

Revenues and Other

Oil, natural gas and NGL sales increased $45 million, or 44% to approximately $147 million for the three months ended September 30, 2018 compared to the three months ended September 30, 2017. The substantial majority of this increase reflects improved oil prices. Additionally, although the July 2017 Hill Acquisition and Hugoton Disposition resulted in lower overall production on an oil equivalent basis, these transactions increased oil volumes as well as the mix of oil production compared to gas production on a quarter-over-quarter basis.

Electricity sales represent sales to utilities and increased by approximately $5 million, or 60%, to approximately $14 million for the three months ended September 30, 2018 compared to the three months ended September 30, 2017.

The increase was primarily due to higher fuel prices in the three months ended September 30, 2018 than the three months ended September 30, 2017.

Losses on oil and natural gas derivatives were approximately $19 million for the three months ended September 30, 2018 compared to a loss of approximately $42 million for the three months ended September 30, 2017. The improvement reflects the May 2018 transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with market pricing at the time.

Marketing and other revenues decreased by approximately $1 million, or 60%, to approximately $0.7 million for the three months ended September 30, 2018, compared to the three months ended September 30, 2017. Marketing revenues in these periods primarily represented sales of third-party natural gas and were comparable. Other revenues in 2017 comprised mostly helium sales, all of which were derived from our Hugoton asset prior to its disposition in July 2017.

Expenses and Other

We report sales of electricity, marketing and transportation activities (as applicable) separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery.

Operating expenses, as defined above, increased to $18.10 per Boe for the quarter ended September 30, 2018 from $17.64 per Boe for the quarter ended September 30, 2017, for the reasons noted below.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased by approximately $5 million, or 12%, to approximately $52 million for the three months ended September 30, 2018, compared to the three months ended September 30, 2017. The increase was primarily due to higher fuel prices, coupled with increased facility chemicals and maintenance costs. Further, lease operating expenses per Boe increased to $20.50 per Boe for the three months ended September 30, 2018 from $17.22 per Boe for the three months ended September 30, 2017, primarily due to the increase in the share of our oil production to 81% of total production from 73% of total production as a result of the Hugoton Disposition (natural gas production) and Hill Acquisition (oil production), which adversely impacted costs per Boe. Replacing low cost natural gas production with oil production in 2017 had a disproportionate impact (oil volume rose 5% and gas volume decreased 25% but cost per Boe rose 20%) on our costs per Boe when comparing these respective periods.

Electricity generation expenses increased approximately $2 million or 34% to $6 million for the three months ended September 30, 2018 and the three months ended September 30, 2017, primarily due to an increase in the price of natural gas.

Transportation expenses decreased by approximately $3 million, or 59%, to approximately $2 million for the three months ended September 30, 2018, compared to the three months ended September 30, 2017, primarily due to the Hugoton Disposition of gas properties, which required significant transportation expense because gas transportation is generally borne by the seller and oil transportation costs are borne by the buyer.

Marketing expenses decreased $0.2 million or 35% to $0.4 million for the three months ended September 30, 2018 compared to the three months ended September 30, 2017, primarily due to the decrease in natural gas prices.

General and administrative expenses increased by approximately $2 million, or 15%, to approximately $13 million for the three months ended September 30, 2018 compared to the three months ended September 30, 2017. The increase in absolute dollars incurred resulted in higher general and administrative expenses of $5.33 per Boe for the three months ended September 30, 2018, compared to $4.37 per Boe for the three months ended September 30, 2017. For the three months ended September 30, 2018 and September 30, 2017, general and administrative expenses included non-recurring restructuring and other costs of approximately $1.6 million and $3.0 million, respectively, and non-cash stock compensation costs of approximately $1.1 million and $0.9 million, respectively. Adjusted general and administrative expenses were $4.25 per Boe for the three months ended September 30, 2018 compared to $2.92 per Boe for the three months ended September 30, 2017. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the company's growth and public company status.

DD&A increased by approximately $1 million, or 4%, to approximately $22 million, for the three months ended September 30, 2018 compared to the three months ended September 30, 2017, primarily due to the Hill Acquisition. The Hill property had a higher depletion rate than the Hugoton field.

Gains on natural gas derivatives of $1.9 million for the three months ended September 30, 2018 represented the mark-to-market valuation on derivative contracts entered into in the third quarter that will begin to settle in the fourth quarter.

Gains on sale of assets and other, net, of $21 million for the three months ended September 30, 2017 primarily related to the gain resulting from the Hugoton Disposition.

Taxes, Other Than Income Taxes

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	September 30, 2017	Variance
	(in thousands)		
Severance taxes	$ 2,149	$ 3,141	$ (992)
Ad valorem and property taxes	3,165	3,829	(664)
Greenhouse gas allowances	3,002	4,812	(1,810)
Total taxes other than income taxes	$ 8,317	$ 11,782	$ (3,465)

Taxes, other than income taxes decreased in the three months ended September 30, 2018 by $3.5 million or 29%, compared to the three months ended September 30, 2017 due to lower severance taxes, ad valorem and property taxes and costs of greenhouse gas allowances. The lower severance taxes in the third quarter were largely a result of lower revenues, the basis for such taxes, in the jurisdictions where severance taxes apply. The lower ad valorem and property taxes were a result of reduced assessments in 2018. The lower greenhouse gas allowance costs in 2018 were a result of additional free allowances received for this period, which reduced the average unit cost of the incurred emissions compared to 2017.

Other income (expenses)

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	September 30, 2017	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$ (9,877)	$ (5,882)	$ (3,995)
Other, net	347	1,155	(808)
Total other income (expense)	$ (9,530)	$ (4,727)	$ (4,803)

Interest expense increased for the three months ended September 30, 2018 by approximately $4 million or 68%, compared to the three months ended September 30, 2017, primarily due to the addition of interest expense on the 2026 Notes, which were issued in February 2018, partially offset by lower interest on the RBL Facility due to the decrease in borrowings period over period. Other, net during the three months ended September 30, 2018 includes interest income and collection of a prior period vendor rebate. Other, net during the three months ended September 30, 2017 primarily includes a gas processing settlement with a third party.

Reorganization items

The following table summarizes the components of reorganization items included in the statement of operations:

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	September 30, 2017	Variance
	(in thousands)		
Return of undistributed funds from Cash Distribution Pool	13,799	—	13,799
Legal and other professional advisory fees	(713)	(408)	(305)
Linn Energy bankruptcy claim receipt	1,500	—	1,500
Other	(805)	—	(805)
Total reorganization items, net	$ 13,781	$ (408)	$ 14,189

Reorganization items, net consisted of a gain of approximately $14 million for the three months ended September 30, 2018, compared to the $0.4 million loss for the three months ended September 30, 2017. The third quarter 2018 gain was primarily due to the return of undistributed funds from the general unsecured creditor pool, coupled with a bankruptcy claim receipt, partially offset by legal and other professional fees. The 2017 loss amount was primarily due to professional fees in support of the reorganization process.

Income taxes

Income tax expense was $7.7 million for the three months ended September 30, 2018, compared to an income tax benefit of $6.2 million for the three months ended September 30, 2017 due to recording pre-tax income in 2018 compared to pre-tax loss in 2017. The decrease in the effective tax rates from 39% in 2017 to 17% in 2018 was primarily a result of the new tax laws for 2018.

Results of Operations - Nine Months Ended September 30, 2018 compared to the Nine Months ended September 30, 2017, including the successor and predecessor periods.

Our results of operations for the nine months ended September 30, 2017 are reflected in the tables and narrative discussion that follow in two distinct periods, the seven months ended September 30, 2017 and the two months ended February 28, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to the nine months ended September 30, 2017 are used to provide comparable periods. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods presented.

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	Berry Corp. (Successor)		Berry LLC (Predecessor)		
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	$ Change	% Change
	(a)	(b)	(c)	(a)-((b)+(c)) = (d)	(d)/((b)+(c))
	(in thousands)				
Revenues and other:					
Oil, natural gas and NGL sales	$ 410,013	$ 237,324	$ 74,120	$ 98,569	32 %
Electricity sales	25,691	15,517	3,655	6,519	34 %
Gains (losses) on oil and natural gas derivatives	(131,781)	5,642	12,886	(150,309)	(811)%
Marketing and other revenues	2,288	5,803	2,057	(5,572)	(71)%
Total revenues and other	306,211	264,286	92,718	(50,793)	(14)%
Expenses and other:					
Lease operating expenses	137,468	105,014	28,238	4,216	3 %
Electricity generation expenses	13,855	10,193	3,197	465	3 %
Transportation expenses	7,640	18,645	6,194	(17,199)	(69)%
Marketing expenses	1,424	1,674	653	(903)	(39)%
General and administrative expenses	37,896	43,529	7,964	(13,597)	(26)%
Depreciation, depletion, amortization and accretion	62,017	48,393	28,149	(14,525)	(19)%
Taxes, other than income taxes	25,288	25,112	5,212	(5,036)	(17)%
(Gains) losses on natural gas derivatives	(1,879)	—	—	(1,879)	— %
(Gains) losses on sale of assets and other, net	522	(20,687)	(183)	21,392	(103)%
Total expenses and other	284,231	231,873	79,424	(27,066)	(9)%
Other income (expenses):					
Interest expense	(26,828)	(12,482)	(8,245)	(6,101)	29 %
Other, net	135	4,071	(63)	(3,873)	(97)%
Reorganization items, net	23,192	(1,001)	(507,720)	531,913	(105)%
Income (loss) before income taxes	18,479	23,001	(502,734)	498,212	(104)%
Income tax expense (benefit)	3,145	9,189	230	(6,274)	(67)%
Net income (loss)	15,334	13,812	(502,964)	504,486	(103)%
Series A preferred stock dividends and conversion to common stock	(97,942)	(12,681)	—	(85,261)	672 %
Net income (loss) available to common stockholders	$ (82,608)	$ 1,131	$ (502,964)	$ 419,225	(84)%

Revenues and Other

Oil, natural gas and NGL sales increased approximately $99 million, or 32% to approximately $410 million for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including the successor and predecessor periods. Additionally, although the July 2017 Hill Acquisition and Hugoton Disposition resulted in lower overall production on an oil equivalent basis, these transactions increased oil volumes as well as the mix of oil production compared to gas production on a period-over-period basis.

Electricity sales represent sales to utilities and increased by approximately $7 million, or 34%, to approximately $26 million for the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017, including the successor and predecessor periods, primarily due to higher prices reflecting higher gas prices, as well as higher volumes sold externally as a result of lower downtime at our cogeneration facilities.

Losses on oil and natural gas derivatives increased to approximately $132 million in the nine months ended September 30, 2018, compared to gains of approximately $19 million in the nine months ended September 30, 2017, including the successor and predecessor periods. Losses on oil and natural gas derivatives in 2018 were primarily due to improved commodity prices relative to the fixed prices of our derivative contracts and an increase in hedging activity.

Marketing and other revenues decreased approximately $6 million or 71% for the nine months ended September 30, 2018 when compared to the nine months ended September 30, 2017, including successor and predecessor periods, primarily due to the lost helium sales revenue as a result of the Hugoton Disposition.

Expenses and other

We report sales of electricity, marketing and transportation activities (as applicable) separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. Operating expenses increased to $18.17 per Boe for the nine months ended September 30, 2018 from $16.23 for the nine months ended September 30, 2017 including the successor and predecessor periods, for the reasons described below.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses in absolute dollars for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including the successor and predecessor periods, reflected higher activity, partially offset by lower fuel gas costs in 2018 compared to 2017. Lease operating expenses per Boe increased to $18.87 per Boe for the nine months ended September 30, 2018, from $14.74 per Boe for the nine months ended September 30, 2017, including the successor and predecessor periods. The increase in the share of our oil production to 81% of total production from 60% as a result of the Hugoton Disposition (natural gas production) and Hill Acquisition (oil production) adversely impacted costs per Boe in 2018 compared to 2017.

Electricity generation expenses increased by $0.5 million or 3% for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including the successor and predecessor periods, primarily due to higher fuel cost and decreased downtime of the cogeneration facilities.

Transportation expenses decreased by approximately $17 million or 69% for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including successor and predecessor periods, primarily due to the Hugoton disposition of gas properties, which required significant transportation expense because gas transportation is generally borne by the seller and oil transportation costs are borne by the buyer.

Marketing expenses decreased $1 million or 39% for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including successor and predecessor periods, primarily due to the decrease in natural gas prices.

General and administrative expenses decreased by approximately $10 million for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including successor and predecessor periods, in terms of absolute dollars. This activity was consistent with our post-emergence efforts to build out our corporate structure while reducing restructuring costs. This also resulted in a decrease in general and administrative expenses per Boe to $5.20 in 2018 from $5.69 in 2017. For the nine months ended September 30, 2018 and 2017, general and administrative expenses included non-recurring restructuring and other costs of approximately $5.4 million and $27.4 million, respectively, and non-cash stock compensation costs of approximately $3.4 million and $0.9 million, respectively. Adjusted general and administrative expenses were $4.00 per Boe for the nine months ended September 30, 2018 compared to $2.52 per Boe for the nine months ended September 30, 2017. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the company's growth and public company status.

Depreciation, depletion and amortization decreased by approximately $15 million, or 20% for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, including successor and predecessor periods, primarily due to the increase in oil and gas reserves in 2018, which resulted in lower DD&A rates and the fair market revaluation of our assets in fresh start accounting which resulted in a lower depreciable asset base in the periods following our emergence from bankruptcy.

Gains on natural gas derivatives of $2 million for the nine months ended September 30, 2018 represent the mark-to-market valuation on derivative contracts entered into in the third quarter that will begin to settle in the fourth quarter.

Gains on sale of assets and other, net, of $21 million for the nine months ended September 30, 2017 primarily related to the gain resulting from the Hugoton Disposition.

Taxes, Other Than Income Taxes

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	**Seven Months Ended September 30, 2017**	**Two Months Ended February 28, 2017**	**Variance**
	(a)	(b)	(c)	(a)-((b)+(c))
	(in thousands)			
Severance taxes	$ 7,910	$ 6,752	$ 1,540	$ (382)
Ad valorem and property taxes	9,723	9,401	2,108	(1,786)
Greenhouse gas allowances	7,655	8,960	1,564	(2,869)
Total taxes other than income taxes	$ 25,288	$ 25,112	$ 5,212	$ (5,036)

Taxes, other than income taxes decreased in the nine months ended September 30, 2018 by $5.0 million or 17%, compared to the nine months ended September 30, 2017, including successor and predecessor periods, due to lower severance taxes, ad valorem and property taxes and costs of greenhouse gas allowances. The lower severance taxes in 2018 were largely a result of lower revenues, the basis for such taxes, in the jurisdictions where severance taxes apply. The lower ad valorem and property taxes were a result of reduced assessments in 2018. The lower greenhouse gas allowance costs in 2018 were a result of additional free allowances received for this period, which reduced the average unit cost of the incurred emissions compared to 2017, partially offset by increased emissions.

Other income (expenses)

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	**Seven Months Ended September 30, 2017**	**Two Months Ended February 28, 2017**	**Variance**
	(a)	(b)	(c)	(a)-((b)+(c))
	(in thousands)			
Interest expense	$ (26,828)	$ (12,482)	$ (8,245)	$ (6,101)
Other, net	135	4,071	(63)	(3,873)
Total other income (expenses)	$ (26,693)	$ (8,411)	$ (8,308)	$ (9,974)

Interest expense increased by $6 million or 29% for the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017, including successor and predecessor periods, due to the additional 7% interest expense on the 2026 Notes which were issued in February 2018, partially offset by lower interest on the RBL Facility due to the decrease in borrowings in the period. Other, net for the seven months ended September 30, 2017 primarily represents the refund of an overpayment on taxes from a prior year.

Reorganization items

The following table summarizes the components of reorganization items included in the statement of operations:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Variance
	(a)	(b)	(c)	(a)-((b)+(c))
	(in thousands)			
Return of undistributed funds from Cash Distribution Pool	$ 22,799	$ —	$ —	$ 22,799
Refund of pre-emergence prepaid costs	579	—	—	—
Gain on settlement of liabilities subject to compromise	—	—	421,774	(421,774)
Fresh start valuation adjustments	—	—	(920,699)	
Legal and other professional advisory fees	(2,515)	(296)	(19,481)	17,262
Gain on resolution of pre-emergence liabilities	1,634	—	—	1,634
Linn Energy bankruptcy claim receipt	1,500	—	—	1,500
Other	(805)	(705)	10,686	(10,786)
Total reorganization items, net	$ 23,192	$ (1,001)	$ (507,720)	$ (389,365)

Reorganization items, net reflected a gain of approximately $23 million for the nine months ended September 30, 2018, compared to an expense of approximately $509 million for the nine months ended September 30, 2017, including successor and predecessor periods. The gain for the nine months ended 2018 was primarily due to a return of $23 million from the funds reserved for the claims of the general unsecured creditors, coupled with a bankruptcy claim receipt and the resolution of pre-emergence liabilities in the amount, partially offset by legal and professional fees.

The loss for the two months ended February 28, 2017 was primarily due to the application of fresh-start accounting in conjunction with our emergence from bankruptcy, partially offset by the gain on settlement of liabilities subject to compromise. Reorganization items represent costs and income directly associated with the Chapter 11 Proceedings and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments are determined.

Income tax expense was $3.1 million for the nine months ended September 30, 2018, compared to an income tax expense of approximately $9.2 million for the seven months ended September 30, 2017 due to recording pre-tax income in 2018 compared to a pre-tax loss in 2017. The decrease in the effective tax rates from 40% in 2017 to 17% in 2018 was primarily a result of the new tax laws for 2018.

For federal and state income tax purposes (with the exception of the State of Texas), the predecessor company was a limited liability company in which income tax liabilities and/or benefits were passed through to our predecessor company's unitholders. Our predecessor company did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of our predecessor company resulting in an effective tax rate of zero for the two months ended February 28, 2017. The successor company was formed as a C Corporation.

Results of Operations - Ten Months Ended December 31, 2017, Two Months Ended February 28, 2017 and Year Ended December 31, 2016

Our results of operations for the year ended December 31, 2017 are reflected in the tables and narrative discussion that follows in two distinct periods, the two months ended February 27, 2017 and the ten months ended December 31, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to “the change” and “the percentage change” compare the year ended December 31, 2016 results to the combined results for the comparison period in 2017 in order to provide comparability of such information. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods presented.

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) Change	% Change
	(audited)	(audited)	(audited)		
	($ in thousands)				
Revenues and other:					
Oil, natural gas and NGL sales	$ 357,928	$ 74,120	$ 392,345	$ 39,703	10 %
Electricity sales	21,972	3,655	23,204	2,423	10 %
Gains (losses) on oil and natural gas derivatives	(66,900)	12,886	(15,781)	(38,233)	(242)%
Marketing revenues	2,694	633	3,653	(326)	(9)%
Other revenues	3,975	1,424	7,570	(2,171)	(29)%
Total revenues and other	319,669	92,718	410,991	1,396	—%
Expenses:					
Lease operating expenses	149,599	28,238	185,056	(7,219)	(4)%
Electricity generation expenses	14,894	3,197	17,133	958	6 %
Transportation expenses	19,238	6,194	41,619	(16,187)	(39)%
Marketing expenses	2,320	653	3,100	(127)	(4)%
General and administrative expenses	56,009	7,964	79,236	(15,263)	(19)%
Depreciation, depletion and amortization	68,478	28,149	178,223	(81,596)	(46)%
Impairment of long-lived assets	—	—	1,030,588	(1,030,588)	(100)%
Taxes, other than income taxes	34,211	5,212	25,113	14,310	57 %
Gains on sale of assets and other, net	(22,930)	(183)	(109)	(23,004)	(21,105)%
Total expenses and other	321,819	79,424	1,559,959	(1,158,716)	(74)%
Other income (expenses)					
Interest expense	(18,454)	(8,245)	(61,268)	34,569	56 %
Other, net	4,071	(63)	(182)	4,190	2,302 %
Reorganization items, net	(1,732)	(507,720)	(72,662)	(436,790)	(601)%
Loss before income taxes	(18,265)	(502,734)	(1,283,080)	762,081	59 %
Income tax expense (benefit)	2,803	230	116	2,917	2,514 %
Net loss	(21,068)	(502,964)	(1,283,196)	759,164	59 %
Dividends on Series A Preferred Stock	(18,248)	n/a	n/a	n/a	n/a
Net income (loss) available to common stockholders	$ (39,316)	n/a	n/a	n/a	n/a

Revenues and Other

Oil, natural gas and NGL sales increased in 2017, including the successor and predecessor periods, by $40 million, or 10%, when compared to the year ended December 31, 2016 due to an increase in realized oil and NGL prices and an increased mix of oil production compared to gas production as a result of the Hill Acquisition and Hugoton Disposition, partially offset by decreased natural gas and NGL production.

Electricity sales increased in 2017, including the successor and predecessor periods, by $2 million, or 10%, when compared to the year ended December 31, 2016 primarily due to higher volumes sold externally because of lower internal usage related to lower steamflood production activity, as well as higher prices.

Losses on oil and natural gas derivatives increased in 2017, including the successor and predecessor periods, by $38 million, or 242%, when compared to the year ended December 31, 2016 primarily due to increased hedging activity, a portion of which was required by the RBL Facility, and improved commodity prices relative to the fixed prices of our derivative contracts.

Marketing revenues in 2017, including the successor and predecessor periods, were comparable to the year ended December 31, 2016.

Other revenues decreased in 2017, including the successor and predecessor periods, by $2 million, or 29%, when compared to the year ended December 31, 2016 due to a decrease in helium gas sales as a result of the Hugoton Disposition.

Expenses

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased in 2017, including the successor and predecessor periods, by $7 million, or 4%, when compared to the year ended December 31, 2016 primarily due to the effect of the Hugoton Disposition (natural gas production) and the Hill Acquisition (oil production), reflecting higher operating expenses associated with natural gas production compared to oil production, and our production decline as a result of decreased development activity and a reduction of steamflooding. While production volumes decreased as a result of the Hugoton Disposition and Hill Acquisition, which decrease adversely impacted costs per Boe, our oil, natural gas and NGL revenues remained constant due to a product mix more heavily weighted towards oil.

Electricity generation expenses increased in 2017, including the successor and predecessor periods, by $1 million, or 6%, when compared to the year ended December 31, 2016, primarily due to the increase in the price of natural gas used in steam generation, for which electricity generation is a by-product.

Transportation expenses decreased in 2017, including the successor and predecessor periods, by $16 million, or 39%, when compared to the year ended December 31, 2016, primarily due to the cancellation of uneconomic contracts in the Chapter 11 Proceedings and the Hugoton Disposition, which required significant transportation expenses.

Marketing expenses in 2017, including the successor and predecessor periods, were comparable to the year ended December 31, 2016.

General and administrative expenses decreased in 2017, including the successor and predecessor periods, by $15 million, or 19%, when compared to the year ended December 31, 2016 primarily due to the management change in conjunction with our emergence from bankruptcy. The reduction in absolute dollars offset by lower production resulted in higher general and administrative expenses per Boe for the year ended December 31, 2017 when compared to the same period in 2016. General and administrative expenses include non-recurring restructuring and other costs of approximately $30 million and non-cash stock compensation costs of approximately $2 million for the ten months ended December 31, 2017. General and administrative expenses in 2016 mainly consisted of allocations from our parent company at the time.

Depreciation, depletion and amortization decreased in 2017, including the successor and predecessor periods, by $82 million, or 46%, when compared to the year ended December 31, 2016, primarily due to the fair market revaluation of our assets in fresh-start accounting resulting in a lower depreciable asset base. The reduction in absolute dollars offset by lower production resulted in lower depreciation, depletion and amortization per Boe for the year ended December 31, 2017, including successor and predecessor periods, when compared to the same period in 2016.

Impairment of Long-Lived Assets

We recorded the following noncash impairment charges associated with proved oil and natural gas properties:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	($ in thousands)		
California operating area	$ —	$ —	$ 984,288
Uinta basin operating area	—	—	26,677
East Texas operating area[1]	—	—	6,387
Piceance basin operating area	—	—	—
Proved oil and natural gas properties	$ —	$ —	$ 1,017,352
Unproved oil and natural gas properties	—	—	13,236
Impairment of long-lived assets	$ —	$ —	$ 1,030,588

(1) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

The impairment charge of $1.0 billion for the year ended December 31, 2016 was primarily due to a decline in commodity prices and changes in expected capital development resulting in a decline of our proved reserves.

Taxes, Other Than Income Taxes

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) change	% change
	(audited)	(audited)	(audited)		
	($ in thousands)				
Severance taxes	$ 8,992	$ 1,540	$ 7,968	$ 2,564	32 %
Ad valorem taxes	11,599	2,108	10,951	$ 2,756	25 %
Greenhouse gas allowances	13,620	1,564	6,063	$ 9,121	150 %
Other	—	—	131	$ (131)	(100)%
Total taxes other than income taxes	$ 34,211	$ 5,212	$ 25,113	$ 14,310	57 %

Taxes, other than income taxes, increased in 2017, including the successor and predecessor periods, by $14 million, or 57%, compared to the year ended December 31, 2016. Severance taxes, which are a function of revenues generated from production in certain jurisdictions, increased in 2017, including successor and predecessor periods, by $2.5 million, or 32%, primarily because of increased revenues. Ad valorem taxes, which are based on the value of reserves and production equipment, and vary by location, increased in 2017, including the successor and predecessor periods, by

$3 million, or 25%, compared to the year ended December 31, 2016, as a result of higher estimated valuations by various tax authorities based on increased commodity prices. Greenhouse gas allowances increased in 2017, including the successor and predecessor periods, by $9 million, or 150%, when compared to the year ended December 31, 2016, primarily due to increased development activity in the second half of 2017 and an increase in the price of allowances.

Gains on Sale of Assets and Other, Net

Gains on sales of assets and other, net increased in 2017, including the successor and predecessor periods, by $23 million, compared to the year ended December 31, 2016, primarily due to the Hugoton Disposition.

Other Income (Expenses)

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) change	% change
	(audited)	(audited)	(audited)		
		($ in thousands)			
Interest expense	$ (18,454)	$ (8,245)	$ (61,268)	$ 34,569	56%
Other, net	4,071	(63)	(182)	4,190	2,302%
Total other income (expenses)	$ (14,383)	$ (8,308)	$ (61,450)	$ 38,759	63%

Interest expense decreased in 2017, including the successor and predecessor periods, by $35 million, or 56%, compared to the year ended December 31, 2016, due to reduced debt resulting from the bankruptcy. Other income, net, for the year ended December 31, 2017, primarily consists of a refund of a federal tax overpayment from a prior year.

Reorganization Items, Net

Reorganization items, net, decreased in 2017, including the successor and predecessor periods by $437 million, or 600%, compared to the year ended December 31, 2016, primarily due to the impact from the application of fresh-start accounting in conjunction with our emergence from bankruptcy during the two months ended February 28, 2017, partially offset by the gain on settlement of liabilities subject to compromise. Reorganization items represent costs and income directly associated with the Chapter 11 Proceedings since May 11, 2016 and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments are determined.

The following table summarizes the components of reorganization items included on the statement of operations:

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) change	% change
	(audited)	(audited)	(audited)		
	($ in thousands)				
Gain on settlement of liabilities subject to compromise	$ —	$ 421,774	$ —	$ 421,774	—
Legal and other professional advisory fees	(1,732)	(19,481)	(30,130)	8,917	30 %
Unamortized premiums	—	—	10,923	(10,923)	(100)%
Terminated contracts	—	—	(55,148)	55,148	100 %
Fresh-start valuation adjustments	—	(920,699)	—	(920,699)	—
Other	—	10,686	1,693	8,993	531 %
Total reorganization items, net	$ (1,732)	$ (507,720)	$ (72,662)	$ (436,790)	(601)%

Income Tax Expense (Benefit)

On the Effective Date, upon consummation of the Plan, we became subject to federal and state income taxes as a C corporation. Prior to the consummation of the Plan, we were treated as a disregarded entity for federal and state income tax purposes as a limited liability company, with the exception of the State of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the State of Texas, we did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for our operations prior to the Effective Date.

Income tax expense increased in 2017, including the successor and predecessor periods, by $3 million when compared to the year ended December 31, 2016 as a result of federal and state alternative minimum tax current taxes and a valuation allowance in excess of net deferred tax assets of $1.9 million due to the impact of applying the Tax Act legislation at the end of 2017.

Liquidity and Capital Resources

Currently, we expect our primary sources of liquidity and capital resources will be Levered Free cash Flow, and as needed, borrowings under the RBL Facility. Depending upon market conditions and other factors, we have issued and may issue additional equity and debt securities; however, we expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to fund maintenance operations, organic growth and opportunistic repurchases of our common stock or debt. We believe our liquidity and capital resources will be sufficient to conduct our business and operations for the next 12 months.

In February 2018, we issued our 2026 Notes, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers’ discount. We used a portion of these net proceeds to repay borrowings under the RBL Facility and used the remainder for general corporate purposes.

In March 2018, our board of directors approved a cumulative paid-in-kind dividend on the Series A Preferred Stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 per share and approximately 1,825,000 shares in total. Also in March 2018, the board approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018. In May 2018, the board of directors approved a $0.15 per share, or approximately $5.6 million cash dividend, on the Series A Preferred Stock for the quarter ended June 30, 2018. The payment was made to stockholders of record as of June 7, 2018.

In July 2018, we completed the IPO and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY. We received approximately $111 million of net proceeds, after deducting underwriting discounts and offering expenses payable by us, for the 8,695,653 shares of common stock issued for our benefit in the IPO, net of the shares sold for the benefit of certain selling stockholders. The price to the public for the shares sold in our IPO was $14.00 per share.

Of the approximately $111 million of net proceeds we received in the IPO, we used approximately $105 million to repay borrowings under our RBL Facility, which included $60 million we borrowed to make the payment due to the holders of our Series A Preferred Stock in connection with the conversion of preferred stock to common stock. We used the remainder for general corporate purposes.

In connection with the IPO, on July 17, 2018, we entered into stock purchase agreements with certain funds affiliated with Oaktree Capital Management and Benefit Street Partners, pursuant to which we purchased an aggregate of 410,229 and 1,391,967 shares of our common stock, respectively, or 1,802,196 in total. In addition to the 8,695,653 shares of common stock issued and sold for our benefit in the IPO, we simultaneously received $24 million for issuing and selling 1,802,196 shares to the public and paid $24 million to purchase 1,802,196 shares under the stock purchase agreements. We purchased the shares immediately following the closing of the IPO and retired and returned them to the status of authorized but unissued shares.

The selling shareholders sold an additional 2,545,630 shares at a price to the public of $14.00 per share for which we did not receive any proceeds.

In connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock was automatically converted in the Series A Preferred Stock Conversion. The cash payment was to be reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. The additional 1.9 million shares of common stock received by the preferred stockholders in the conversion were assigned a value of $14.00 per share in the IPO.

On August 21, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock on a pro-rated basis from the date of our IPO through September 30, 2018 which resulted in a payment of $0.09 per share on October 15, 2018 to shareholders of record as of September 15, 2018. On November 7, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the fourth quarter.

The RBL Facility contains certain financial covenants, including the maintenance of (i) a Leverage Ratio (as defined in the RBL Facility) not to exceed 4.00:1.00 and (ii) a Current Ratio (as defined in the RBL Facility) not to be less than 1.00:1.00. As of September 30, 2018, our Leverage Ratio and Current Ratio were 1.85:1.00 and 4.21:1.00, respectively. As of September 30, 2018 our borrowing base was approximately $400 million and we had $393 million available for borrowing under the RBL Facility. At September 30, 2018, we were in compliance with the financial covenants under the RBL Facility. In connection with the issuance of the 2026 Notes, the RBL Facility borrowing base was set at $400 million, which incorporated a $100 million reduction, or 25%, of the face value of the 2026 Notes. In November 2018, we completed a borrowing base redetermination under our $1.5 billion RBL Facility that increased our borrowing base to $850 million and reaffirmed our elected commitment amount at $400 million. We can increase our elected commitment amount up to the borrowing base with lender approval. Borrowing base redeterminations become effective on, or about, each May 1 and November 1, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations.

Historically, our predecessor company utilized funds from debt offerings, borrowings under its credit facility and net cash provided by operating activities, as well as funding from our former parent, for capital resources and liquidity, and the primary use of capital was for the development of oil and natural gas properties.

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including through fixed-price derivative contracts. As of September 30, 2018, we have hedged crude oil production of approximately 1.2 MMBbls for 2018, 6.0 MMBbls for 2019 and 0.5 MMBbls for 2020.

Future cash flows are subject to a number of variables discussed in Risk Factors in this prospectus. Further, our capital investment budget for the year ended December 31, 2018, does not allocate any amounts for acquisitions of oil and natural gas properties. If we make acquisitions, we would be required to reduce the expected level of capital investments or seek additional capital. If we require additional capital we may seek such capital through borrowings under the RBL Facility, joint venture partnerships, production payment financings, asset sales, additional offerings of debt or equity securities or other means. We cannot be sure that needed capital would be available on acceptable terms or at all. If we are unable to obtain funds on acceptable terms, we may be required to curtail our current development programs, which could result significant declines in our production.

See "—Factors Affecting the Comparability of Our Financial Condition and Results of Operations - Capital Expenditures and Capital Budget" for a description of our 2018 capital expenditure budget and expected 2019 capital expenditure budget.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Berry Corp. (Successor)			Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
			($ in thousands)		
Net cash:					
Provided by (used in) operating activities	$ 7,334	$ 107,399	$ 70,505	$ 22,431	$ 13,197
Used in investing activities	(82,375)	(80,525)	(74,563)	(3,133)	(34,602)
Provided by (used in) financing activities	30,216	(43,170)	(43,049)	(162,668)	(1,701)
Net decrease in cash, cash equivalents and restricted cash	$ (44,825)	$ (16,296)	$ (47,107)	$ (143,370)	$ (23,106)

Operating Activities

Cash provided by operating activities was approximately $7 million for the nine months ended September 30, 2018 compared to cash provided by operating activities of approximately $93 million for the nine months ended September 30, 2017, including the successor and predecessor periods. The amounts provided by operating activities in 2018 included $127 million paid for early-terminated hedges which partially offset $134 million of cash provided by other operating activities. Excluding the impact of these early hedge termination payments, the increase in cash provided by operating activities in 2018 compared to 2017 reflected higher sales and lower operating costs slightly offset by negative working capital effects and scheduled derivative cash settlements.

Cash provided by operating activities increased for the year ended December 31, 2017, including successor and predecessor periods, by approximately $117 million when compared to the same period in 2016, primarily due to the increases in the price of oil and natural gas, and decreases in operating expenses, interest expense and costs incurred in conjunction with our emergence from bankruptcy.

Investing Activities

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

	Berry Corp. (Successor)			Berry LLC (Predecessor)	
	Nine Months Ended September 30, 2018	**Ten Months Ended December 31, 2017**	**Seven Months Ended September 30, 2017**	**Two Months Ended February 28, 2017**	**Year Ended December 31, 2016**
			($ in thousands)		
Capital expenditures [1]					
Development of oil and natural gas properties	$ (74,447)	$ (65,479)	$ (38,445)	$ (859)	$ (34,796)
Purchase of other property and equipment	(11,305)	0	(11,497)	(2,299)	0
Proceeds from sale of properties and equipment and other	3,377	234,292	234,823	25 —	194
Acquisition of properties	—	(249,338)	(259,444)	—	—
Cash used in investing activities:	$ (82,375)	$ (80,525)	$ (74,563)	$ (3,133)	$ (34,602)

(1) Based on actual cash payments rather than accrual.

Cash used in investing activities was approximately $82 million for the nine months ended September 30, 2018. The increase in cash used for investing activities for the nine months ended September 30, 2018 when compared to the same period in 2017 including the successor and predecessor periods, was primarily due to an increase in capital spending in accordance with the 2018 capital budget. Investing activities for the same period in 2017 included the Hill Acquisition and the Hugoton Disposition.

Cash used in investing activities increased in 2017, including the successor and predecessor periods, by $49 million compared to the year ended December 31, 2016, due to the Hill Acquisition, partially offset by the Hugoton Disposition and the increase in capital expenditures. Capital expenditures increased in 2017, including the successor and predecessor periods, by $34 million, or 97%, compared to the year ended December 31, 2016, primarily due to development of oil and gas properties as a result of increased liquidity. Our liquidity improved significantly in 2017 due to our emergence from bankruptcy, improved commodity prices, decreased costs and entry into the RBL Facility.

Financing Activities

Cash provided by financing activities was approximately $30 million for the nine months ended September 30, 2018 and was due to the net proceeds of $391 million from the issuance of our 2026 Notes and $111 million, net, from our IPO in July, offset by $379 million payments on our RBL Facility, a $60 million payment to preferred stockholders when their preferred shares were converted to common stock in the IPO, a $20 million payment to repurchase the right to our common shares from certain claimholders originating from the bankruptcy process, $11 million cash dividends declared on our Series A Preferred Stock. For the nine months ended September 30, 2017, including the successor and predecessor periods, net cash used in financing activities related to payments on our previous and current credit facilities of approximately $949 million and $12 million, respectively, offset by the receipt of proceeds from the issuance of our Series A Preferred Stock of $335 million, borrowings under the RBL Facility of approximately $391 million and under the previous facility of $51 million.

Cash used in financing activities was approximately $43 million for the ten months ended December 31, 2017 and was primarily related to repayments of the Emergence Credit Facility and payments of debt issuance costs for the RBL Facility, partially offset by borrowings under the new RBL Facility. Cash used in financing activities was approximately $163 million for the two months ended February 28, 2017 and was primarily related to the repayments on the Pre-Emergence Credit Facility partially offset by the receipt of proceeds from the issuance of our Series A Preferred Stock.

Cash used in financing activities was approximately $2 million for the year ended December 31, 2016 and was primarily related to repayments on the Pre-Emergence Credit Facility.

Debt

2026 Notes Offering

In February 2018, we issued $400 million in aggregate principal amount of our 2026 Notes, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers' discount. We used the net proceeds from the issuance to repay the $379 million outstanding balance on the RBL Facility and used the remainder for general corporate purposes.

We may, at our option, redeem all or a portion of the 2026 Notes at any time on or after February 15, 2021. We are also entitled to redeem up to 35% of the aggregate principal amount of the 2026 Notes before February 15, 2021, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107% of the principal amount of the 2026 Notes being redeemed, plus accrued and unpaid interest, if any. In addition, prior to February 15, 2021, we may redeem some or all of the 2026 Notes at a price equal to 100% of the principal amount thereof, plus a "make-whole" premium, plus any accrued and unpaid interest. If we experience certain kinds of changes of control, holders of the 2026 Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the 2026 Notes, plus accrued and unpaid interest, if any.

The 2026 Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. The notes are fully and unconditionally guaranteed on a senior unsecured basis by us and will also be guaranteed by certain of our future subsidiaries (other than Berry LLC). The 2026 Notes and related guarantees are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under the RBL Facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the 2026 Notes.

The indenture governing the 2026 Notes contains restrictive covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness
- transfer, sell or dispose of assets;
- make investments;
- create certain liens securing indebtedness;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets; and
- engage in transactions with affiliates.

The indenture governing the 2026 Notes contains customary events of default, including, among others, (a) non-payment; (b) non-compliance with covenants (in some cases, subject to grace periods); (c) payment default under, or acceleration events affecting, material indebtedness and (d) bankruptcy or insolvency events involving us or certain of our subsidiaries.

The RBL Facility

On July 31, 2017, Berry LLC, as borrower, entered into the RBL Facility. The RBL Facility provides for a revolving loan with up to $1.5 billion of commitments, subject to a reserve borrowing base, and provided an initial commitment of $500 million. The RBL Facility also provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. Borrowing base redeterminations become effective on or about each May 1 and November 1, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. In connection with the issuance of the 2026 Notes, the RBL Facility borrowing base was set at $400 million, which incorporated a $100 million reduction, or 25%, of the face value of the 2026 Notes. In November 2018, we completed a borrowing base redetermination under our RBL Facility that increased our borrowing base to $850 million and reaffirmed our elected commitment amount at $400 million. We can increase our elected commitment amount up to the borrowing base with lender approval. As of September 30, 2018, we had approximately $7 million in letters of credit outstanding and borrowing availability of $393 million under the RBL Facility. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

The outstanding borrowings under the revolving loan bear interest at a rate equal to either (i) a customary London interbank offered rate plus an applicable margin ranging from 2.50% to 3.50% per annum, and (ii) a customary base rate plus an applicable margin ranging from 1.50% to 2.50% per annum, in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.50% on the average daily unused amount of the borrowing availability under the RBL Facility. We have the right to prepay any borrowings under the RBL Facility with prior notice at any time without a prepayment penalty, other than customary “breakage” costs with respect to eurodollar loans.

Berry Corp. guarantees, and each future subsidiary of Berry Corp. (other than Berry LLC), with certain exceptions, is required to guarantee, our obligations and obligations of the other guarantors under the RBL Facility and under certain hedging transactions and banking services arrangements (the “Guaranteed Obligations”). In addition, pursuant to a Guaranty Agreement dated as of July 31, 2017 (the “Guaranty Agreement”), Berry LLC guarantees the Guaranteed Obligations. The lenders under the RBL Facility hold a mortgage on at least 85% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions. The RBL Facility, with certain exceptions, also requires that any future subsidiaries of Berry LLC will also have to grant mortgages, security interests and equity pledges.

The RBL Facility requires us to maintain on a consolidated basis as of September 30, 2017 and each quarter-end thereafter (i) a Leverage Ratio of no more than 4.00 to 1.00 and (ii) a Current Ratio of at least 1.00 to 1.00. The RBL Facility also contains customary restrictions that may limit our ability to, among other things:

- incur or guarantee additional indebtedness;
- transfer, sell or dispose of assets;
- make loans to others;
- make investments;
- merge with another entity;
- make or declare dividends;
- hedge future production or interest rates;
- enter into transactions with affiliates;
- incur liens; and

- engage in certain other transactions without the prior consent of the lenders.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral.

Pre-Emergence Credit Facility and Emergence Credit Facility

As of December 31, 2016, we had approximately $898 million in total borrowings outstanding (including approximately $7 million in outstanding letters of credit) under the Pre-Emergence Credit Facility and no remaining availability. All outstanding obligations under the Pre-Emergence Credit Facility were canceled and the agreements governing these obligations were terminated on the Effective Date. Also on the Effective Date, Berry LLC entered into the Emergence Credit Facility. Initial borrowings under the RBL Facility were primarily incurred to repay borrowings made under the Emergence Credit Facility. All outstanding obligations under the Emergence Credit Facility were canceled, and the agreements governing these obligations were terminated on July 31, 2017.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

On May 11, 2016 our predecessor company filed the Chapter 11 Proceeding. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding. On February 28, 2017, the Effective Date occurred and the Plan became effective and was implemented. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at September 30, 2018 and December 31, 2017. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of September 30, 2018, we are not aware of material indemnity claims pending or threatened against us.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of December 31, 2017:

Contractual Obligations	Payments Due				
	Total	2018	2019-2020	2021-2022	2023 and Beyond
	($ in thousands)				
Debt obligations:					
RBL Facility	$ 379,000	$ —	$ —	$ 379,000	$ —
Interest(1)	86,698	18,949	37,898	29,851	—
Other:					
Commodity derivatives	75,281	49,949	25,332	—	—
Firm natural gas transportation contracts(2)	9,590	1,751	3,474	3,336	1,029
Off-Balance Sheet arrangements:					
Operating lease obligations	2,750	1,349	1,226	175	—
Purchase obligations and other(3)	20,045	14,045	6,000	—	—
Total contractual obligations	$ 573,364	$ 86,043	$ 73,930	$ 412,362	$ 1,029

(1) Represents interest on the RBL Facility computed at 4.8% through contractual maturity in 2022.

(2) We enter into certain firm commitments to transport natural gas production to market and to transport natural gas for use in our cogeneration and conventional steam generation facilities. The remaining terms of these contracts range from approximately five to seven years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

(3) Included in these obligations are natural gas purchase contracts for our cogeneration facilities, valued at approximately $14 million, and purchase obligations of approximately $6 million related to a commitment to either (a) invest at least $9 million to extend an existing access road in connection with our Piceance assets or construct a new access road, or (b) pay 50% of the difference between $12 million and the actual amount spent on such access road construction prior to the end of 2019. If we do not obtain extensions for the road obligation, we may trigger the payment obligation which, if we were unable to negotiate resolution, would reduce our capital available for investment.

During the nine months ended September 30, 2018, there were no significant changes in our consolidated contractual obligations from those at December 31, 2017, except as noted elsewhere in Management's Discussion and Analysis of Financial Condition and Results of Operations, including commodity derivatives. In addition, we transferred our Texas delivery commitments in conjunction with the sale of our non-core oil and gas properties in the East Texas Basin, which was completed on November 30, 2018.

Supplemental Quarterly Financial Data

	Berry Corp. (Successor)		
	Quarters Ended		
	March 31, 2018	June 30, 2018	September 30, 2018
	(in thousands)		
Total revenues and other[(1)]	$ 97,284	$ 65,982	$ 142,947
Total expenses[(2)]	$ 91,121	$ 90,458	$ 102,130
(Gains) losses on sale of assets and other, net	$ —	$ 123	$ 400
Reorganization items, net, expense (income)	$ 8,955	$ 456	$ 13,781
Net income (loss)	$ 6,410	$ (28,061)	$ 36,985
Net income (loss) available to common stockholders	$ 760	$ (33,711)	$ (49,657)
Earnings (loss) per share attributable to common stockholders:			
Basic	$ 0.02	$ (0.84)	$ (0.66)
Diluted	$ 0.02	$ (0.84)	$ (0.66)

(1) Includes net derivative gains (losses).
(2) Includes the following expenses: lease operating, transportation, electricity generation, marketing, general and administrative, depreciation, depletion and amortization, impairment of long-lived assets and taxes, other than income taxes.

Quantitative and Qualitative Disclosures About Market Risk

Our primary market risks are attributable to fluctuations in commodity prices and interest rates, which can affect our business, financial condition, operating results and cash flows. The following should be read in conjunction with the financial statements and related notes included elsewhere in this prospectus.

Price Risk

Our most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of our oil and gas properties may be required if commodity prices experience a significant decline.

We have hedged a large portion of our expected crude oil production and our natural gas requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls and puts to hedge. We have not entered into derivative contracts for speculative trading purposes. We continuously consider the level of our production that it is appropriate to hedge based on a variety of factors, including, among other things, current and future expected commodity prices, our overall risk profile, including leverage, size and scale, as well as any requirements for, or restrictions on, levels of hedging contained in any credit facility or other debt instrument applicable at the time. Currently, our hedging program mainly consists of swaps and puts. We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, the RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, or otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from Standards & Poor's or Moody's, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which mitigates the counterparty nonperformance risk somewhat. The maximum amount of loss due to credit risk that we would incur if the counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was zero at September 30, 2018, as we held no derivative asset positions with any of our counterparties.

Our commodity derivatives are measured at fair value using industry-standard models with various inputs including publicly available underlying commodity prices and forward curves. At September 30, 2018, the fair value of our hedge positions was a net liability of approximately $31 million. A 10% increase in the oil and natural gas index prices above the September 30, 2018 prices would result in a net liability of approximately $71 million, which represents a decrease in the fair value of our derivative position of approximately $40 million; conversely, a 10% decrease in the oil and natural gas index prices below the September 30, 2018 prices would result in a net asset of approximately $2 million, which represents an increase in the fair value of approximately $33 million. For additional information about derivative activity, see Note 4 to our consolidated financial statements for the nine months ended September 30, 2018.

As of December 31, 2017, we had a net derivative liability of $75.3 million carried at fair value, as determined from prices provided by external sources that are not actively quoted. A 10% increase in the index oil and natural gas prices above the December 31, 2017 prices would result in a net liability of approximately $133 million which represents a decrease in the fair value of approximately $57 million; conversely, a 10% decrease in the index oil and natural gas prices below the December 31, 2017 prices, would result in a net liability of approximately $18 million, which represents an increase in the fair value of approximately $57 million. We determine the fair value of our oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets.

We determine the fair value of our oil and natural gas derivatives utilizing pricing models that use a variety of techniques including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets.

Actual gains or losses recognized related to our derivative contracts depend exclusively on the price of the underlying commodities on the specified settlement dates provided by the derivative contracts. Additionally, we cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our cash flows could be negatively impacted.

Counterparty Credit Risk

We account for our commodity derivatives at fair value. We had eight commodity derivative counterparties at September 30, 2018 and five at December 31, 2017. We did not receive collateral from any of our counterparties. We minimize the credit risk of our derivative instruments by limiting our exposure to any single counterparty. In addition, the RBL Facility prevents us from entering into hedging arrangements that are secured except with our lenders and their affiliates, that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from Standard & Poor’s or Moody’s, respectively. In accordance with our standard practice, our 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. Considering these factors together, we believe exposure to credit losses related to our business at September 30, 2018 was not material and losses associated with credit risk have been insignificant for all periods presented.

Interest Rate Risk

Our RBL Facility has a variable interest rate on outstanding balances. As of December 31, 2017, we had debt outstanding under the RBL Facility of approximately $379 million. As of December 31, 2017, a 1% increase in the respective market rate would result in an estimated $4 million increase in annual interest expense. We used a portion of the proceeds from the issuance of the 2026 Notes to repay borrowings under the RBL Facility in February 2018. As of September 30, 2018, there were no borrowings under our RBL Facility and thus we were not exposed to interest rate risk on this facility. The 2026 Notes have a fixed interest rate and thus we are not exposed to interest rate risk on these. See Note 3 to our consolidated financial statements for the nine months ended September 30, 2018 for additional information regarding interest rates on outstanding debt.

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with generally accepted accounting principles requires management to select appropriate accounting policies and to make informed estimates and judgments regarding certain items and transactions. Changes in facts and circumstances or discovery of new information may result in revised estimates and judgments, and actual results may differ from these estimates upon settlement. We consider the following to be our most critical accounting policies and estimates that involve management’s judgment and that could result in a material impact on the financial statements due to the levels of subjectivity and judgment.

Fresh-Start Accounting

Upon our emergence from Chapter 11 bankruptcy, we adopted fresh-start accounting which resulted in our becoming a new entity for financial reporting purposes. We were required to adopt fresh-start accounting upon our emergence from Chapter 11 bankruptcy because (i) the holders of existing voting ownership interests of Berry LLC received less than 50% of the voting shares of Berry Corp. and (ii) the reorganization value of our assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims, as shown below:

		($ in thousands)
Liabilities subject to compromise	$	1,000,336
Pre-petition debt not classified as subject to compromise		891,259
Post-petition liabilities		245,702
Total post-petition liabilities and allowed claims		2,137,297
Reorganization value of assets immediately prior to implementation of the Plan		(1,722,585)
Excess post-petition liabilities and allowed claims	$	414,712

Upon adoption of fresh-start accounting, the reorganization value derived from the enterprise value was allocated to our assets and liabilities based on their fair values in accordance with GAAP. The Effective Date fair values of our assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet. The effects of the Plan and the application of fresh-start accounting were reflected in the financial statements as of February 28, 2017, and the related adjustments thereto were recorded on the statement of operations for the two months ended February 28, 2017.

As a result of the adoption of fresh-start accounting and the effects of the implementation of the Plan, our consolidated financial statements subsequent to February 28, 2017 are not comparable to our financial statements prior to February 28, 2017.

Our consolidated financial statements and related footnotes are presented with a black line division, which delineates the lack of comparability between amounts presented after February 28, 2017, and amounts presented on or prior to February 28, 2017. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

Reorganization Value

Under GAAP, Berry Corp. determined a value to be assigned to the equity of the emerging entity as of the date of adoption of fresh-start accounting. The Plan and disclosure statement approved by the Bankruptcy Court did not include an enterprise value or reorganization value, nor did the Bankruptcy Court approve a value as part of its confirmation of the Plan. Our reorganization value was derived from an estimate of enterprise value, or the fair value of our long-term debt, stockholders' equity and working capital. Reorganization value approximates the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Based on the various estimates and assumptions necessary for fresh-start accounting, we estimated our enterprise value as of the Effective Date to be approximately $1.3 billion. The enterprise value was estimated using a sum of parts approach. The sum of parts approach represents the summation of the indicated fair value of the component assets of the Company. The fair value of our assets was estimated by relying on a combination of the income, market and cost approaches.

The estimated enterprise value, reorganization value and equity value are highly dependent on the achievement of the financial results contemplated in our underlying projections. While we believe the assumptions and estimates used to develop enterprise value and reorganization value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. Additionally, the assumptions used in estimating these values are inherently uncertain and require judgment. The primary assumptions for which there is a reasonable possibility of the occurrence of a variation that would have significantly affected the reorganization value include those regarding pricing, discount rates and the amount and timing of capital expenditures.

Our principal assets are our oil and natural gas properties. The fair values of oil and natural gas properties were estimated using a valuation technique consistent with the income approach, specifically the discounted cash flows method. We also used the market approach to corroborate the valuation results from the income approach. We used a market-based weighted average cost of capital discount rate of 10% for proved and unproved reserves, with further risk adjustment factors applied to the discounted values. The underlying commodity prices embedded in our estimated cash flows are based on the ICE (Brent) and NYMEX (HH) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that we believe will impact realizable prices. Forward curve pricing was used for years 2017 through 2019 and then was escalated at approximately 2.0%.

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date:

	($ in thousands)
Enterprise value	$ 1,278,527
Plus: Fair value of non-debt liabilities	282,511
Reorganization value of the successor’s assets	$ 1,561,038

The fair value of non-debt liabilities consists of liabilities assumed by Berry Corp. on the Effective Date and excludes the fair value of long-term debt.

Consolidated Balance Sheet

The adjustments included in the fresh-start consolidated balance sheet in the accompanying financial statements reflect the effects of the transactions contemplated by the Plan and executed on the Effective Date as well as fair value and other required accounting adjustments resulting from the adoption of fresh-start accounting. The explanatory notes provide additional information with regard to the adjustments recorded, methods used to determine the fair values and significant assumptions.

Oil and Natural Gas Properties

Proved Properties

We account for oil and natural gas properties in accordance with the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively. Costs of retired, sold or abandoned properties that constitute a part of an amortization base 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 the current period. Gains or losses from the disposal of other properties are recognized in the current period. For assets acquired, we base the capitalized cost on fair value at the acquisition date. We expense expenditures for maintenance and repairs necessary to maintain properties in operating condition, as well as annual lease rentals, as they are incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized over the remaining lives of the related assets. We only capitalized this interest on borrowed funds related to our share of costs associated with qualifying capital expenditures. Interest is capitalized only during the periods in which these assets are brought to their intended use. The amount of capitalized interest and exploratory well costs in 2017 and 2016 was not significant.

We evaluate the impairment of our proved oil and natural gas properties generally on a field by field basis or at the lowest level for which cash flows are identifiable, whenever events or changes in circumstance indicate that the carrying value may not be recoverable. We reduce the carrying values of proved properties to fair value when the expected undiscounted future cash flows are less than net book value. We measure the fair values of proved properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a risk-adjusted discount rate. These inputs require significant judgments and estimates by our management at the time of the valuation and are the most sensitive estimates that we make and the most likely to change. The underlying commodity prices are embedded in our estimated cash flows and are the product of a process that begins with the relevant forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors our management believes will impact realizable prices.

Impairment of Proved Properties

Based on the analysis described above, for the year ended December 31, 2016, we recorded noncash impairment charges of approximately $1.0 billion associated with proved oil and natural gas properties. The 2016 impairment charges were due to a decline in commodity prices, changes in expected capital development and a decline in our estimates of proved reserves. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges were included in “impairment of long-lived assets” on our statements of operations.

Unproved Properties

A portion of the carrying value of our oil and gas properties was attributable to unproved properties. At December 31, 2017 and 2016, the net capitalized costs attributable to unproved properties were approximately $517 million and $680 million, respectively. The unproved amounts were not subject to depreciation, depletion and amortization until they were classified as proved properties and amortized on a unit-of-production basis. We evaluate the impairment of our unproved oil and gas properties whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of such properties would be expensed. The timing of any write-downs of unproved properties, if warranted, depends upon management’s plans, the nature, timing and extent of future exploration and development activities and their results.

We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance at December 31, 2017. Based on the analysis described above, for the year ended December 31, 2016, we recorded noncash impairment charges of approximately $13 million associated with unproved oil and natural gas properties. The impairment charges in 2016 were primarily due to a decline in commodity prices and changes in expected capital development. The carrying values of the impaired unproved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in “impairment of long-lived assets” on our statements of operations.

Asset Retirement Obligation

We recognize the fair value of asset retirement obligations (“AROs”) in the period in which a determination is made that a legal obligation exists to dismantle an asset and remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated.

The liability amounts were based on future retirement cost estimates and incorporate many assumptions such as time to abandonment, technological changes, future inflation rates and the risk-adjusted discount rate. When the liability was initially recorded, we capitalized the cost by increasing the related property, plant and equipment (“PP&E”) balances. If the estimated future cost of the AROs changes, we record an adjustment to both the ARO and PP&E. Over time, the liability is increased, and expense is recognized through accretion, and the capitalized cost is depreciated over the useful life of the asset.

In certain cases, we do not know or cannot estimate when we may settle these obligations and therefore we cannot reasonably estimate the fair value of the liabilities. We will recognize these AROs in the periods in which sufficient information becomes available to reasonably estimate their fair values.

Revenue Recognition

We recognize revenue from oil, natural gas and NGL production when title has passed from us to the purchaser, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. We recognize our share of revenues net of any royalties and other third-party share. In addition, we engage in the purchase, gathering and transportation of third-party natural gas and subsequently market such natural gas to independent purchasers under separate arrangements. As a result, we separately report third-party marketing revenues and marketing expenses.

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques: Level 1—using quoted prices in active markets for the assets or liabilities; Level 2—using observable inputs other than quoted prices for the assets or liabilities; and Level 3—using unobservable inputs. Transfers between levels, if any, are recognized at the end of each reporting period. We primarily apply the market approach for recurring fair value measurement, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows and discounts those cash flows using a risk-adjusted discount rate.

The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives. Commodity derivatives are carried at fair value. In addition to using market data in determining these fair values, we make assumptions about the risks inherent in the inputs to the valuation technique. Our commodity derivatives comprise OTC bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including publicly available prices and forward curves generated from a compilation of data gathered from third parties. We validate the data provided by third parties by assessing the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. Substantially all of these inputs are observable data or are supported by observable prices at which transactions are executed in the marketplace. We classify these measurements as Level 2.

Stock-based Compensation

Subsequent to February 28, 2017, we issued restricted stock units ("RSUs") that vest over time and performance-based restricted stock units ("PRSUs") that vest based on our achievement of certain average prices per share, to certain employees and non-employee directors. The fair value of the stock-based awards is determined at the date of grant and is not remeasured. We determined the fair value of the RSUs based on an estimate of the fair value of our equity using an income approach. We used a discounted cash flow method to value the estimated future cash flows at an appropriate discount rate. Since the underlying shares are now trading in the public markets, these estimates are no longer necessary. For PRSUs, compensation value is measured on the grant date using payout values derived from a Monte-Carlo valuation model. Estimates used in the Monte Carlo valuation model are considered highly complex and subjective. Compensation expense, net of actual forfeitures, for the RSUs and PRSUs is recognized on a straight-line basis over the requisite service periods, which is generally over the awards' respective three-year vesting or performance periods.

Other Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to loss in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management’s judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management’s plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Recently Adopted Accounting Standards

In August 2018, the SEC issued a final rule requiring registrants to analyze and disclose changes in stockholders' equity in the form of a reconciliation for the current and comparative year-to-date interim periods with subtotals for each interim period. We adopted this rule in the quarter ended September 30, 2018 and modified our statements of equity accordingly.

In March 2016, the Financial Accounting Standards Board (“FASB”) issued rules to improve the accounting for share-based payment transactions. We early-adopted these rules retrospectively on April 1, 2018 and as a result are reporting cash paid to tax authorities when we withhold shares from an employee’s award as a cash outflow for financing activities on the statement of cash flows. There was no change to the other financial statements as a result of adopting these rules.

In November 2016, the FASB issued rules intended to address the diversity in practice in classification and presentation of changes in restricted cash on the statement of cash flows. We adopted these rules retrospectively on January 1, 2018, as a result of which we included restricted cash amounts in our beginning and ending cash balances on the statement of cash flows and included a disclosure reconciling cash and cash equivalents presented on the balance sheets to cash, cash equivalents and restricted cash on the statement of cash flows.

New Accounting Standards Issued, But Not Yet Adopted

In February 2016, the FASB issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and do not expect a material impact on our consolidated results of operations.

During 2016, the FASB issued rules clarifying the new revenue recognition standard issued in 2014. The new rules are intended to improve and converge the financial reporting requirements for revenue from contracts with customers. We are an emerging growth company and have elected to delay adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 31, 2018. We do not expect the adoption of these rules to materially change our reporting of revenue, however, we expect that certain amounts currently reported as expense will be reported as offsets to revenue.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the periods discussed. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we may experience inflationary pressure on the cost of oilfield services and equipment as increasing oil, natural gas and NGL prices increase drilling activity in our areas of operations. An increase in oil, natural gas and NGL prices may cause the costs of materials and services to rise.

Off-Balance Sheet Arrangements

See “—Liquidity and Capital Resources—Lawsuits, Claims, Commitments, Contingencies and Contractual Obligations” for information regarding our off-balance sheet arrangements.

BUSINESS

Our Company

We are a California-based independent upstream energy company engaged primarily in the development and production of conventional oil reserves located onshore in the western United States. Our long-lived, predictable and high margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive free cash flow through commodity price cycles. We believe that executing our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient production growth as well as the ability to return excess free cash flow to stockholders.

We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and the Uinta basin of Utah, and, to a lesser extent, the low geologic risk natural gas resource play in the Piceance basin in Colorado. In the aggregate, the Company's assets are characterized by:

- high oil content, which makes up more than 80% of our production;
- favorable Brent-influenced crude oil pricing dynamics;
- long-lived reserves with low and predictable production decline rates;
- stable and predictable development and production cost structures;
- a large inventory of low-risk identified development drilling opportunities with attractive full-cycle economics; and
- potential in-basin organic and strategic opportunities to expand our existing inventory with new locations of substantially similar geology and economics.

California is and has been one of the most productive oil and natural gas regions in the world. Our asset base is concentrated in the oil-rich San Joaquin basin in California, which has more than 100 years of production history and substantial remaining oil in place. As a result of these attributes, we have a strong understanding of many of the basin's geologic and reservoir characteristics, leading to predictable, repeatable, low-risk development opportunities.

In California, we focus on conventional, shallow reservoirs, the drilling and completion of which are relatively low-cost in contrast to modern unconventional resource plays. Our decades-old proven completion techniques in these reservoirs include steamflood and low-volume fracture stimulation. For example, we estimate the cost for PUD wells drilled and completed in California will average less than $450,000 per well. In contrast, we estimate the cost of PUD wells drilled and completed in the Piceance basin will average $1.8 million per well. Using SEC Pricing as of December 31, 2017, there were approximately 80 gross PUD locations associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.

We own additional assets in the Uinta basin in Utah, a stacked, multi-bench, light-oil-prone play with significant undeveloped resources where we have high operational control and additional behind pipe potential and in the Piceance basin in Colorado, a prolific low geologic risk natural gas play where we produce from a conventional, tight sandstone reservoir using proven slick water fracture stimulation techniques to increase recoveries. On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Using SEC Pricing as of December 31, 2017, we had estimated total proved reserves of 141,384 MBoe. For the three months ended September 30, 2018, we had average production of approximately 27.4 MBoe/d, of which approximately 81% was oil. In California, our average production for the three months ended September 30, 2018 was 19.5 MBoe/d, of which approximately 100% was oil.

The Berry Advantage

We believe that our combination of low production decline rates, high margin oil-weighted production, attractive development opportunities and a stable cost environment differentiates us from our competitors and provides for low-breakeven commodity prices and an ability to generate top-tier corporate level returns, positive Levered Free Cash Flow and capital-efficient growth through commodity price cycles.

Our Low Declining Production Base

Our reserves are generally long-lived and characterized by relatively low production decline rates, affording us significant capital flexibility and an ability to efficiently hedge material quantities of future expected production. For example, our PDP reserves have an estimated annual decline rate of approximately 14% to 12% in the years between 2018 and 2022 based on total PDP Boe reserves as of December 31, 2017 as reflected in our SEC reserve report, which is attached as Annex A. Our SEC reserve report is based on the estimated individual well production profiles used to determine our PDP reserves. Based on the assumptions underlying our PUD estimates, we estimate that we will require approximately $10 per Boe in annual capital expenses to keep production volumes consistent each year over the next three years.

Our Oil-Weighted, High Margin Production

Our highly oil-weighted production combined with a Brent-influenced California pricing dynamic and stable cost structures has resulted, and is expected to continue to result, in strong operating margins. As of December 31, 2017, our California PUD reserves were 100% oil.

Our Attractive Development Opportunities

Our estimated development costs associated with our PUD reserves are $8.89 per Boe on a total company basis and $10.95 per Boe in California. We believe that our estimated development costs, when combined with our operating costs, commodity mix and price realizations, present attractive breakeven economics for our development opportunities.

We expect our identified drilling locations to generate attractive rates of return. The following table presents our expected average single-well rates of return on drilling opportunities associated with our California PUD reserves based on the assumptions used in preparing our December 31, 2017 SEC reserve report, including pricing and cost assumptions, which can be found under “Primary Economic Assumptions” on page 6 of our reserve report. Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude development in the Piceance basin. As a result, information with respect to our Colorado PUDs as of December 31, 2017 has been omitted from the table below. The table also includes a commodity price sensitivity scenario, which is based on Strip Pricing as of May 31, 2018.

	PUD Weighted-Average Economics			
	Per Well		IRR	
Asset	EUR (MBOE)	D&C ($ in thousands)	SEC Pricing as of December 31, 2017[(1)]	Strip Pricing as of May 31, 2018[(2)]
California	45	<$ 450	37%	73%

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX (HH) for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate, $28.25 per barrel of NGL and $2.935 per thousand cubic feet of gas. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules, including adjustment by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Please see “—Our Reserves and Production Information.”

(2) Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018, without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX (HH). The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. Please see "—Our Reserves and Production Information."

Our Stable California Operating and Development Cost Environment

The operating and development cost structures of our conventional California asset base are inherently stable and predictable. Our California focus largely insulates us from the cost inflation pressures experienced by our peers who operate primarily in unconventional plays. This is the result of our established infrastructure, low-intensity service requirements and lack of dependence on inventory-constrained and often highly specialized equipment. In addition, the majority of our California assets reside in the shallow steam-flood fields of the San Joaquin basin, which are lower cost to develop compared to the water flood fields of the Los Angeles and Ventura basins.

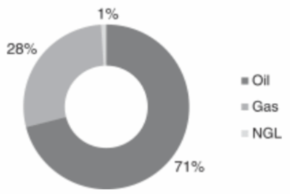
Our Reserves and Assets

The majority of our reserves are composed of heavy crude oil in shallow, long-lived reservoirs. Approximately two-thirds of our proved reserves and approximately 90% of the PV-10 value of our proved reserves are derived from our assets in California. We also operate in the Uinta basin in Utah, a stacked, multi-bench, light-oil-prone play with significant undeveloped resources and in the Piceance basin in Colorado, a prolific natural gas play with low geologic risk. On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

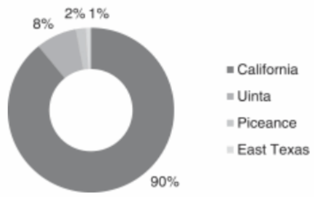
Using SEC Pricing as of December 31, 2017, the standardized measure of discounted future net cash flows of our proved reserves and the PV-10 of our proved reserves were approximately $1.0 billion and $1.1 billion, respectively. Using Strip Pricing as of May 31, 2018, the PV-10 of our proved reserves was approximately $1.9 billion. PV-10 is a financial measure that is not calculated in accordance with GAAP. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "Prospectus Summary—Summary Reserves and Operating Data—PV-10."

The charts below summarize certain characteristics of our proved reserves and PV-10 of proved reserves using SEC Pricing as of December 31, 2017 and Strip Pricing as of May 31, 2018 (as described in the tables below and in "Prospectus Summary—Summary Reserves and Operating Data"):

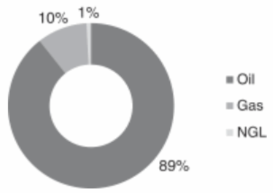
1P Reserves by Commodity (SEC Pricing)
(141 MMBoe)



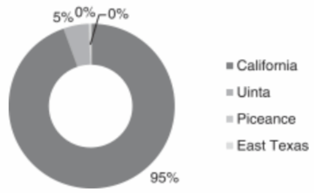
1P PV-10 by Area (SEC Pricing)
($1.1 billion)



1P Reserves by Commodity (Strip Pricing)
(115 MMBoe)



1P PV-10 by Area (Strip Pricing)
($1.9 billion)



The tables below summarize our proved reserves and PV-10 by category using SEC Pricing as of December 31, 2017 and Strip Pricing as of May 31, 2018:

	SEC Pricing as of December 31, 2017[(1)]							
	Oil (MMBbl)	**Natural Gas (Bcf)**	**NGLs (MMBbl)**	**Total (MMBoe)**	**% of Proved**	**% Proved Developed**	**Capex[(2)] ($MM)**	**PV-10[(3)] ($MM)**
PDP	63	100	1	81	57%	93%	$ 50	$ 762
PDNP	6	—	—	6	4%	7%	10	89
PUD[(5)]	32	137	—	55	39%	—%	488	262
Total	101	237	1	141	100%	100%	$ 548	$ 1,114

	Strip Pricing as of May 31, 2018[(4)]							
	Oil (MMBbl)	**Natural Gas (Bcf)**	**NGLs (MMBbl)**	**Total (MMBoe)**	**% of Proved**	**% Proved Developed**	**Capex[(2)] ($MM)**	**PV-10[(3)] ($MM)**
PDP	64	67	1	77	67%	93%	$ 50	$ 1,205
PDNP	6	—	—	6	5%	7%	10	136
PUD	32	—	—	32	28%	—%	348	521
Total	102	67	1	115	100%	100%	$ 407	$ 1,862

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX (HH) for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per Bbl of oil and condensate, $28.25 per Bbl of NGL and $2.935 per MMBtu of gas. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules, including adjustment by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Please see "Prospectus Summary—Summary Reserves and Operating Data."

(2) Represents undiscounted future capital expenditures as of December 31, 2017.
(3) PV-10 is a financial measure that is not calculated in accordance with GAAP. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "Prospectus Summary—Summary Reserves and Operating Data—PV-10." PV-10 does not give effect to derivatives transactions.
(4) Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX (HH). The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. The decrease in reserve volumes using Strip Pricing as opposed to SEC Pricing is primarily the result of lower realized gas prices in Colorado using Strip Pricing as of May 31, 2018. Please see "Prospectus Summary—Summary Reserves and Operating Data."
(5) Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude the development in the Piceance basin.

The table below summarizes our average net daily production by basin for the three months ended September 30, 2018:

	Average Net Daily Production[1] for the Three Months Ended September 30, 2018	
	(MBoe/d)	Oil (%)
California	19.5	100%
Uinta basin	5.1	54%
Piceance basin	2.0	1%
East Texas basin[2]	0.7	1%
Total	27.4	81%

(1) Production represents volumes sold during the period.
(2) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Our Development Inventory

We have an extensive inventory of low-risk, high-return development opportunities. As of September 30, 2018, we identified 3,386 Tier 1 gross drilling locations company-wide and 3,799 additional gross drilling locations that are currently under review. For a discussion of how we identify drilling locations, please see "—Our Reserves and Production Information—Determination of Identified Drilling Locations."

We operate over 95% of our productive wells and expect to operate a similar percentage of our identified gross drilling locations. In addition, approximately 75% of our acreage is held by production, including 99% of our acreage in California. Our high degree of operational control, together with the large portion of our acreage that is held by production, gives us flexibility over the execution of our development program, including the timing, amount and allocation of our capital expenditures, technological enhancements and marketing of production.

The following table summarizes certain information concerning our operations as of September 30, 2018:

	Acreage		Net Acreage Held By Production(%)	Producing Wells, Gross[(1)(2)]	Average Working Interest (%)[(2)(4)]	Net Revenue Interest (%)[(2)(5)]	Identified Drilling Locations[(3)]	
	Gross	Net					Gross	Net
California	10,926	8,015	99%	2,563	99%	94%	4,991	4,983
Uinta basin	130,677	95,912	72%	935	95%	78%	1,244	1,083
Piceance basin	10,533	8,008	85%	170	72%	63%	870	664
East Texas basin[(6)]	5,853	4,533	100%	116	99%	74%	80	79
Total	157,989	116,468	75%	3,784	97%	88%	7,185	6,809

(1) Includes 486 steamflood and waterflood injection wells in California.
(2) Excludes 91 wells in the Piceance basin each with a 5% working interest.
(3) Our total identified drilling locations include approximately 790 gross (786 net) locations associated with PUDs as of December 31, 2017, including 161 gross (161 net) steamflood and waterflood injection wells. Please see "—Our Reserves and Production Information—Determination of Identified Drilling Locations" for more information regarding the process and criteria through which we identified our drilling locations.
(4) Represents our weighted average working interest in our active wells.
(5) Represents our weighted average net revenue interest for the nine months ended September 30, 2018.
(6) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Additionally, our California assets are primarily focused on the Hill Diatomite, Thermal Diatomite and Thermal Sandstones development areas. As set forth in the table below, as of September 30, 2018, we identified 3,386 Tier 1 gross drilling locations company-wide and 3,799 additional gross drilling locations that are currently under review associated with these assets.

					Gross Drilling Locations[(1)]		
State	Project Type	Well Type	Completion Type	Recovery Mechanism	Tier 1[(2)]	Additional	Total
California	Hill Diatomite (non-thermal)	Vertical	Low intensity pin point fracture	Pressure depletion augmented with water injection	285	585	870
California	Thermal Diatomite	Vertical	Short interval perforations	Cyclic steam injection	795	979	1,774
California	Thermal Sandstones	Vertical / Horizontal	Perforation/Slotted liner/gravel pack	Continuous and cyclic steam injection	1,855	492	2,347
Utah	Uinta	Vertical / Horizontal	Low intensity fracture stimulation	Pressure depletion	451	793	1,244
Colorado[(3)]	Piceance	Vertical	Proppantless slick water fracture stimulation	Pressure depletion	—	870	870
Texas[(4)]	East Texas	Vertical / Horizontal	Low intensity fracture stimulation	Pressure depletion	—	80	80
Total					**3,386**	**3,799**	**7,185**

(1) We had 790 gross (786 net) locations associated with PUDs as of December 31, 2017 using SEC Pricing, including 161 gross (161 net) steamflood and waterflood injection wells. Of those 790 gross PUD locations, 710 are associated with projects in California and 80 are associated with the Piceance basin. Please see "—Our Reserves and Production Information—Determination of Identified Drilling Locations" for more information regarding the process and criteria through which we identified our drilling locations. During the nine months ended September 30, 2018, we drilled 86 gross (86 net) wells that were associated with PUDs at December 31, 2017, including 25 gross (25 net) steamflood and waterflood injection wells.
(2) Represents wells that we anticipate drilling over the next 5 to 10 years.
(3) Using SEC Pricing as of December 31, 2017, there were 80 gross PUD locations associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.
(4) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Other Assets

We produce oil from heavy crude reservoirs using steam to heat the oil so that it will flow. To assist in this development, we own and operate five natural gas cogeneration plants that produce steam. These plants supply approximately 23% of our steam needs and approximately 43% of our field electricity needs in California at a discount to electricity market prices. To further offset our costs, we currently also sell surplus power produced by three of our cogeneration facilities under long-term contracts with California utility companies.

In addition, we own gathering, treatment and storage facilities in California that currently have excess capacity, reducing our need to spend capital to develop nearby assets and generally allowing us to control certain operating costs. We also own a network of oil and gas gathering lines across our assets outside of California, and our oil and natural gas is transported through such lines and third-party gathering systems and pipelines.

We also own a natural gas processing plant with capacity of approximately 30 MMcf/d in the Brundage Canyon area, located in Duchesne County, Utah. This facility takes delivery from gathering and compression facilities we operate. Approximately 90% of the gas gathered at these facilities is produced from wells that we operate. Current throughput at the processing plant is 16-18 MMcf/d and sufficient capacity remains for additional large-scale development drilling.

Our Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategy.

- ***Stable, low-decline, predictable and oil-weighted conventional asset base***. The majority of our interests are in properties that have produced for decades. As a result, the geology and reservoir characteristics are well understood, and new development well results are generally predictable, repeatable and present lower risk than unconventional resource plays. The properties are characterized by long-lived reserves with low production decline rates, a stable cost structure and low-risk developmental drilling opportunities with predictable production profiles. The nature of our assets provides us with a high degree of capital flexibility through commodity cycles.

- ***Substantial inventory of low-cost, low-risk and high-return development opportunities***. We expect our locations to generate highly attractive rates of return. For example, our proved undeveloped reserves in California are projected to average single-well rates of return of approximately 37%, assuming SEC Pricing as of December 31, 2017, based on the assumptions used in preparing our SEC reserve report, which can be found under “Primary Economic Assumptions” on page 6 of our reserve report, and 73% assuming Strip Pricing as of May 31, 2018, based on the assumptions found in the Strip Pricing addendum to our reserve report. Our extensive inventory consists of 3,386 Tier 1 gross drilling locations company-wide and 3,799 additional gross drilling locations that are currently under review.

- ***Brent-influenced pricing advantage***. California oil prices are Brent-influenced as California refiners import more than 50% of the state’s demand from foreign sources. There is a closer correlation of prices in California to Brent pricing than to WTI. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, will allow us to continue to realize strong cash margins in California.

- ***Experienced, principled and disciplined management team***. Our management team has significant experience operating and managing oil and gas businesses across numerous domestic and international basins, as well as reservoir and recovery types. We will employ our deep technical, operational and strategic management experience to optimize the value of our assets and the Company. We are focused on the principles of growing Levered Free Cash Flows as well as the value of our production and reserves. In doing so, we take a disciplined approach to development and operating cost management, field development efficiencies and the application of proven technologies and processes new to our properties in order to generate a sustained cost advantage.

- ***Substantial capital flexibility derived from a high degree of operational control and stable cost environment***. We operate over 95% of our productive wells and expect to operate a similar percentage of our identified gross drilling locations. In addition, approximately 75% of our acreage is held by production, including 99% of our acreage in California. Our high degree of operational control over our properties, together with the large portion of our acreage that is held by production, gives us flexibility over the execution of our development program, including the timing, amount and allocation of our capital expenditures, technological enhancements and marketing of production. We expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to fund maintenance operations and growth among other things. Also, unlike our peers who operate primarily in unconventional plays, our assets generally do not necessitate inventory-constrained and highly specialized equipment, which provides us relative insulation from cost inflation pressures. Our high degree of operational control and relatively stable cost environment provide us significant visibility and understanding of our expected cash flows.

- ***Conservative balance sheet leverage with ample liquidity and minimal contractual obligations***. In February 2018, we closed the 2026 Notes offering, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers' discount. As of September 30, 2018, we had $417 million of available liquidity, defined as cash on hand plus availability under the RBL Facility. In addition, we have minimal long-term service or fixed-volume delivery commitments. This liquidity and flexibility permit us to capitalize on opportunities that may arise to grow and increase stockholder value.

Our Business Strategy

The principal elements of our business strategy include the following:

- ***Grow production and reserves in a capital efficient manner while producing positive internally generated Levered Free Cash Flow***. We intend to allocate capital in a disciplined manner to projects that will produce predictable and attractive rates of return. We plan to direct capital to our oil-rich and low-risk development opportunities while focusing on driving cost efficiencies across our asset base with the primary objective of internally funding our capital budget and growth plan. We may also use our capital flexibility to pursue value-enhancing, bolt-on acquisitions to opportunistically improve our positions in existing basins.

- ***Maximize ultimate hydrocarbon recovery from our assets by optimizing drilling, completion and production techniques and investigating deeper reservoirs and areas beyond our known productive areas***. While we intend to utilize proven techniques and technologies, we will also continuously seek efficiencies in our drilling, completion and production techniques in order to optimize ultimate resource recoveries, rates of return and cash flows. We will explore innovative EOR techniques to unlock additional value and have allocated capital towards next generation technologies. For example, in our South Belridge Hill non-thermal and Midway-Sunset thermal Diatomite properties, we employ both fracture stimulation and advanced thermal techniques, and in our Piceance properties, we use advanced proppantless slick water fracture stimulation techniques. In addition, we intend to take advantage of underdevelopment in basins where we operate by expanding our geologic investigation of deeper reservoirs on our acreage and adjacent acreage below existing producing reservoirs. Through these studies, we will seek to expand our development beyond our known productive areas in order to add probable and possible reserves to our inventory at attractive all-in costs.

- ***Proactively and collaboratively engage in matters related to regulation, safety, environmental and community relations***. We are committed to proactive engagement with regulatory agencies in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with law and regulations. We expect our work with regulators and legislators throughout the rule making process to minimize any adverse impact that new legislation and regulations might have on our ability to maximize our resources. We have found constructive dialogue with regulatory agencies can help avert compliance issues.

- ***Maintain balance sheet strength and flexibility through commodity price cycles***. We intend to fund our capital program while producing positive internally generated Levered Free Cash Flow. Over time, we expect to de-lever through organic growth and with excess Levered Free Cash Flow. Our objective is to achieve and maintain a long-term, through-cycle leverage ratio between 1.5x and 2.0x.

- ***Return excess free cash flow to stockholders***. Our objective is to implement a disciplined and returns-focused approach to capital allocation in order to generate excess free cash flow. We intend to return portions of that excess free cash flow to stockholders on a quarterly basis. If commodity prices increase for a sustained period of time, we would consider repaying debt obligations or returning additional capital to shareholders. For a discussion of our dividend policy, please see “Dividend Policy.”

- ***Enhance future cash flow stability and visibility through an active and continuous hedging program***. Our hedging strategy is designed to insulate our capital program from price fluctuations by securing price realizations and cash flows, including fixed-price gas purchase agreements and other hedging contracts. We have protected a portion of our anticipated production into 2020 as part of our crude oil hedging program. We will review our hedging program continuously as conditions change.

Our Capital Budget

Following Berry LLC’s emergence from bankruptcy and separation from the Linn Entities, we increased our pace of development and have continued to do so in 2018. Our 2018 anticipated capital expenditure budget of approximately $140 to $160 million represents an increase of approximately 107% over our 2017 capital expenditures, including the successor and predecessor periods, of approximately $73 million. Our 2019 anticipated capital expenditure budget is approximately $230 to $260 million. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2018 and 2019 capital programs while producing positive Levered Free Cash Flow. We expect to:

- employ:
  - three drilling rigs in California for the remainder of 2018;
  - one additional drilling rig assigned to drilling opportunities in Utah in the fourth quarter of 2018; and
  - an average of four rigs in California in 2019; and
- drill approximately 230 to 250 gross development wells in 2018, of which we expect at least 235 will be in California, and 400 to 450 gross development wells in 2019, almost all of which we expect will be in California.

The amount and timing of these capital expenditures is within our control and subject to our management’s discretion. We retain the flexibility 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, natural gas and NGLs, 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 interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and materially affect our business, financial condition and results of operations.

Our Areas of Operation

We have two operating areas in the western United States, including California and the Rockies. On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

California

According to the U.S. Geological Survey as of 2012, the San Joaquin basin in California contained three of the 10 largest oil fields in the United States based on cumulative production and proved reserves. We have operations in two of the largest fields in California—Midway-Sunset and South Belridge. California is and has been one of the most productive oil and natural gas regions in the world.

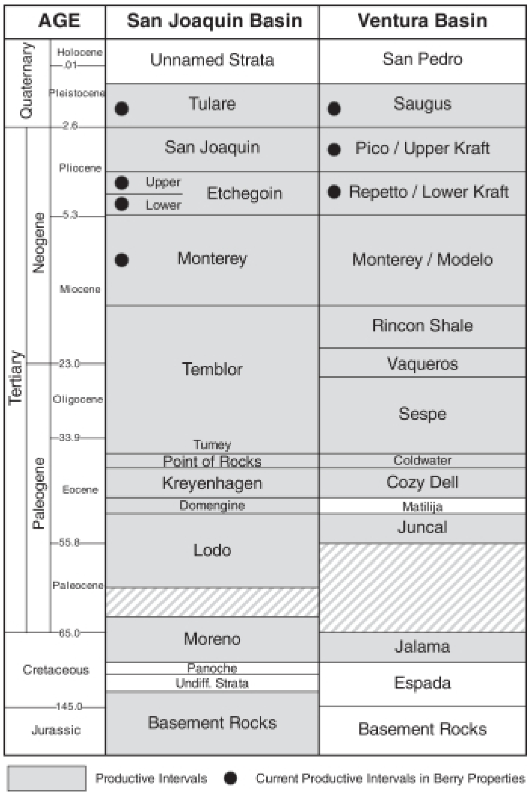
Our California operating area consists of properties located in the Midway-Sunset, South Belridge, McKittrick and Poso Creek fields in the San Joaquin basin in Kern County as well as the Placerita Field in the Ventura basin in Los Angeles County. The producing areas in our Southeast San Joaquin operations include: (i) our Midway-Sunset, Homebase, Formax and Ethel D leases, which are long-life, low-decline, strong-margin oil properties with additional development opportunities; (ii) our Poso Creek property, which is an active mature steamflood asset that we continue to develop across the property; and (iii) our Placerita property, which is a mature steamflood asset with additional recompletion opportunities. The producing areas in our Northwest San Joaquin operations include: (i) our McKittrick Field 21Z property, which is a new steamflood development with potential for infill and extension drilling; (ii) our South Belridge Field Hill property, which is characterized by two known reservoirs with low geological risk containing a significant number of drilling prospects, including downspacing opportunities, as well as additional steamflood opportunities; and of which we purchased the remaining approximately 84% working interest in the third quarter of 2017; (iii) our thermal Diatomite Midway-Sunset properties, where we utilize innovative EOR techniques to unlock significant value and maximize recoveries; and (iv) our sandstone Midway-Sunset properties, where we use cyclic and continuous steam injection to develop these known reservoirs. Our California proved reserves represented approximately 66% of our total proved reserves at December 31, 2017 and accounted for 19.5 MBoe/d, or 71%, of our actual average daily production for the three months ended September 30, 2018.

According to the Division of Oil, Gas, and Geothermal Resources of the California Department of Conservation (“DOGGR”), approximately 81% of California’s daily oil production for 2016 was produced in the San Joaquin basin. Commercial petroleum development began in the San Joaquin basin in the late 1860s when asphalt deposits were mined and shallow wells were hand dug and drilled. Rapid discovery of many of the largest oil accumulations followed during the next several decades. We began operations in California in 1909. In the 1960s, introduction of thermal techniques resulted in substantial new additions to reserves in heavy oil fields. The San Joaquin basin contains multiple stacked benches that have allowed continuing discoveries of stratigraphic, structural and non-structural traps. Most oil accumulations discovered in the San Joaquin basin occur in the Eocene age through Pleistocene age sedimentary sections. Organic rich shales from the Monterey, Kreyenhagen and Tumey formations form the source rocks for these accumulations. We believe there are extensive existing field redevelopment opportunities in our areas of operation within the San Joaquin basin. We believe that our California focus and strong balance sheet will allow us to take advantage of these opportunities.

We actively operate and develop four fields in the San Joaquin and Ventura basins consisting of IOR and EOR project types. We currently hold approximately 8,015 net acres in the San Joaquin and Ventura basins with a 99% average working interest. We have extensive infrastructure and excess available takeaway capacity in place to support additional development in California. This infrastructure includes five cogeneration facilities, 79 conventional steam generators, gathering lines and processing facilities inclusive of oil and gas processing, water recycling and softening facilities among other standard industry equipment. The majority of our oil production is sold through pipeline connections, and we have contracts in place with third-party purchasers of our crude.

Stratigraphic Chart of San Joaquin and Ventura basins

California is home to several basins characterized by extensive production history, long reserve life and multiple producing horizons. As shown in the table below, the basins where we operate contain multiple stacked formations throughout their depths that include both conventional and unconventional opportunities. We currently operate in the formations highlighted below; however, we believe the stacked reservoirs within our asset base provide exposure to additional upside potential in several emerging resource plays.



Rockies

Uinta basin

Formed during the late Cretaceous to Eocene periods, the Uinta basin is a mature multi-bench, oil-prone play located primarily in Duchesne and Uintah Counties of Utah and covers more than 15,621 square miles. Exploration efforts immediately after the Second World War led to the first commercial oil discoveries in the Uinta basin. Oil was discovered in, and produced from fluvial to lacustrine sandstones of the Green River formation in these early discoveries. The application of improved hydraulic fracturing techniques in the mid-2000s greatly increased production from the Uinta basin. As reported by the Utah Department of Natural Resources, total Utah production more than doubled from 36 MBbl/d in 2003 to 93 MBbl/d in 2017. Approximately 82% of Utah’s production in 2017 came from the Uinta basin in Duchesne and Uintah counties.

Surface indications of petroleum in Utah were noted by explorers as early as 1850, but drilling efforts in the late nineteenth and early twentieth centuries failed to find commercial quantities of oil. The first commercial discoveries were made in the late 1940s in the northern Uinta basin. The Uinta productive area expanded significantly over the last few decades, and the introduction of improved hydraulic fracturing methodologies improved per well recoveries since the mid 2000s. We entered the Uinta basin in 2003 with the acquisition of assets in Brundage Canyon and continued to grow our assets to today. We believe continued exploration and development drilling in the Uinta basin, especially in proximity to our assets, coupled with improvements in drilling and completion techniques will continue to provide us with development and growth opportunities going forward.

Our Uinta basin operations in the Brundage Canyon, Ashley Forest and Lake Canyon areas target the Green River and Wasatch formations that produce oil and natural gas at depths ranging from 5,000 feet to 8,000 feet. We have high operational control of approximately 1,244 identified gross vertical drilling locations and additional behind pipe potential, with significant upside for additional vertical and/or horizontal development and recompletions on existing acreage. For a discussion of how we identify drilling locations, please see "—Our Reserves and Production Information—Determination of Identified Drilling Locations." We also have extensive infrastructure and available takeaway capacity in place to support additional development along with existing gas transportation contracts. Rejection of an oil sales contract and various transportation contracts in connection with our predecessor company's bankruptcy restructuring resulted in significantly improved sales net of royalties, production and transportation expenses. We have a natural gas gathering systems consisting of approximately 500 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. We also own a natural gas processing plant in the Brundage Canyon area with capacity of approximately 30 MMcf/d. Our Uinta basin proved reserves represented approximately 11% of our total proved reserves at December 31, 2017 and accounted for 5.1 MBoe/d, or 19%, of our average daily production for the three months ended September 30, 2018.

Piceance basin

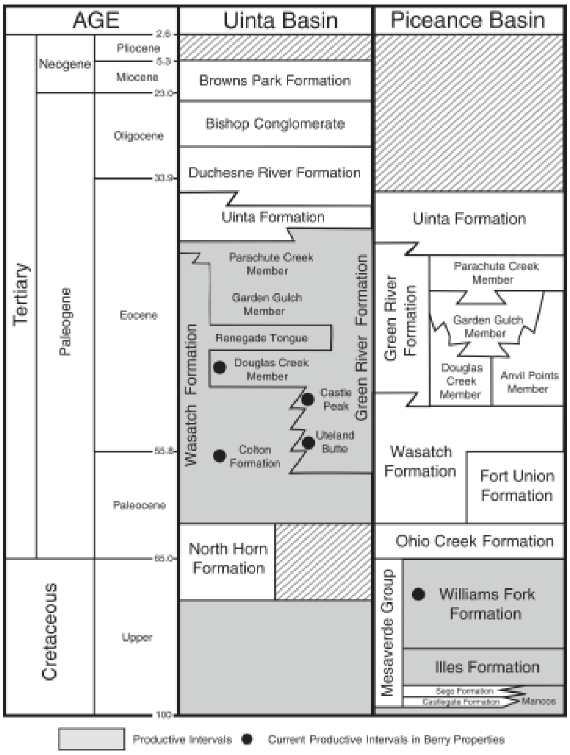
The Piceance basin is located in northwestern Colorado and is a low geologic risk gas play with trillions of cubic feet of natural gas in place. Natural gas generated from coals and carbonaceous shales in the Upper Cretaceous Mesaverde Group migrated into low permeability Mesaverde Group fluvial sandstones resulting in a basin-centered gas accumulation, or what the U.S. Geological Survey terms a "continuous petroleum accumulation." Operators recognized for years that the Mesaverde Group, and the Williams Fork formation in particular, contained significant quantities of gas over a large area, but the low permeability of the reservoir sandstones made it difficult to complete economic wells. Improvements in hydraulic fracture design and completion fluids in the 1990s and 2000s, coupled with an increase in commodity prices, led to the economic development of the gas resources in the Piceance basin.

Our primary operating areas in the Piceance basin are Garden Gulch and North Parachute where we target the Williams Fork formation of the Mesaverde Group and produce at depths ranging from 7,500 feet to 12,500 feet. In addition to more than 800 identified gross drilling locations and a proven slick water completion method that has resulted in lower costs and increased recoveries, we have infrastructure and available takeaway capacity in place to support additional development along with existing gas transportation contracts. Our Piceance basin proved reserves represented approximately 21% of our total proved reserves at December 31, 2017 and accounted for 2.0 MBoe/d, or 7%, of our average daily production for the three months ended September 30, 2018.

In addition to the more than 800 identified gross drilling locations in the Williams Fork formation, we believe significant potential exists in the Late Cretaceous Mancos shale that underlies the Mesaverde group. The Mancos shale is over 4,000 feet thick in the Piceance basin and was deposited in the Cretaceous interior seaway. The unit consists of marine shale along with interbedded sandstone, carbonates and organic units. Operators have successfully drilled and completed commercial wells in the Mancos Shale, and in 2016 the U.S. Geological Survey assessed technically recoverable mean resources of 66 trillion cubic feet of natural gas and 45 MMBbls of NGLs from this continuous petroleum accumulation.

Stratigraphic Chart of Uinta and Piceance basins

Because of the stratigraphic similarities and shared geologic history between the Uinta and Piceance basins, the U.S. Geological Survey describes the basins as the Uinta-Piceance Petroleum Province. Five total petroleum systems have been identified spanning in age from the Pennsylvanian to the Eocene periods, including both conventional and unconventional opportunities. We produce from the formations highlighted in the following stratigraphic chart, predominantly oil in the Uinta basin and gas in the Piceance basin. The oil produced from the Green River and Wasatch formation reservoirs in the Uinta basin are derived from lacustrine oil-prone source rocks that were deposited in Lake Uinta during the Eocene period. The extent and richness of these petroleum systems across the Uinta-Piceance Petroleum Province provide us development upside in both stacked pays and potential deeper reservoirs.



Operational Overview

We generally seek to be the operator of our properties so that we can develop and implement drilling programs and optimization projects that not only replace production, but add value through reserve and production growth and future operational synergies. Many of our properties have long histories of successful development. Additional opportunities exist to continue using successful development techniques while also embracing new incremental recovery technologies. The long-lived nature of our properties allows us to continually seek operational efficiencies to enhance value creation through all operational phases.

Thermal Recovery

Most of our assets in California consist of heavy crude oil, which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize steamflooding on these assets and have not yet begun to use additional tertiary methods to further produce oil from our reserves. We have cyclic and continuous steam injection projects in the San Joaquin and Ventura basins, primarily in Kern County and in fields such as Midway-Sunset, Poso Creek, McKittrick, South Belridge and Placerita, with demonstrated internal and third-party results across thousands of wells. Historically, we start production from heavy oil reservoirs with cyclic injection and then expand operations to include continuous injection in adjacent wells. We intend to continue employing both recovery techniques as long as a favorable oil to gas price spread exists. Full development of these projects typically takes multiple years and involves upfront infrastructure construction for steam and water processing facilities and follow on development drilling. These steam injection projects are generally shallower in depth (300 to 1,200 ft) than our other programs and the wells are relatively inexpensive to drill at approximately $375,000 per well. Therefore, we can normally implement a drilling program quickly with attractive rates of return. For the three months ended September 30, 2018, our total gross average production from thermal recovery projects was 17.8 MBoe/d. We monitor our steam injection closely on each individual project and increase or decrease steam to maximize the value return of each project. As of September 30, 2018, we were injecting over 149,000 barrels of steam daily.

Cogeneration Steam Supply and Conventional Steam Generation

We believe one of the primary methods to keep steam costs low is through the ownership and efficient operation of cogeneration facilities. We own five cogeneration facilities: (i) a 38 MW facility ("Cogen 38"), an 18 MW facility ("Cogen 18"), and two separate 5 MW facilities ("Pan Fee and 21Z CoGens"), each located in the Midway-Sunset Field and (ii) a 42 MW facility ("Cogen 42") located in the Placerita Field. Cogeneration, also called combined heat and power, extracts energy from the exhaust of a turbine to produce steam and increases the efficiency of the combined process. For more information please see "—Electricity."

We own 79 fully permitted conventional steam generators. The number of generators operated at any point in time is dependent on the steam volume required to achieve our targeted injection rate and the price of natural gas compared to our oil production rate and the realized price of oil sold. Ownership of these varied steam generation facilities allows for maximum operational control over the steam supply, location and, to some extent, the aggregated cost of steam generation. Our steam supply and flexibility are crucial for the maximization of thermally enhanced heavy oil production in California, cost control and ultimate oil recovery. The natural gas we purchase to generate steam and electricity is primarily based on California price indexes. We pay distribution and transportation charges for the delivery of natural gas to our various locations where we use the natural gas for steam generation purposes. In some cases, this transportation cost is embedded in the price of the natural gas we purchase.

Low Volume Fracture Stimulation

Fracture stimulation is an important and common practice we use to stimulate production of oil and gas. The process involves injection of water, sand and trace chemicals under pressure into underground oil and gas bearing rock formations to create or enlarge fractures and stimulate the flow of oil and gas into the oil and gas production well. Our California fracture stimulation projects use significantly lower fluid volumes than is typical in other areas. For example, we expect to use approximately 147,000 gallons of water per well for our Hill fracture stimulations compared to a median of nearly 4 million gallons for horizontal wells fractured in the United States in 2014. Similarly, we expect to use only about 324,000 pounds of sand per Hill well compared to a nationwide average of over 4 million pounds of sand per well in 2015. We use this method of reservoir stimulation in the San Joaquin basin to stimulate our non-thermal Diatomite reservoir at the Hill property. In 2017, we did not spend capital on this method of reservoir stimulation. We plan to apply this technique in 2018 and beyond on our inventory of Hill non-thermal Diatomite development wells. We use more traditional fracture stimulation to complete our wells in the Piceance basin. In this area, we use "proppantless stimulation" to stimulate the reservoir with water and no proppant. In 2017, we did not spend capital on this method of reservoir stimulation. We plan to apply this technique, which has increased both initial rates and EURs versus previous stimulation methods, in 2018 and beyond on our inventory of Piceance development wells.

Our Midstream Infrastructure

We own a network of oil and gas gathering lines across our assets, and our oil and natural gas is transported through such lines and third-party gathering systems and pipelines. When moving through the third-party systems, we incur processing, gathering and transportation expenses to move our oil and natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume, distance shipped and the fee charged by the third-party processor or transporter.

We also own a natural gas processing plant with capacity of approximately 30 MMcf/d in the Brundage Canyon area, located in Duchesne County, Utah. This facility takes delivery from gathering and compression facilities we operate. Approximately 90% of the gas gathered at these facilities is produced from wells that we operate. The system gathers and dehydrates the product, removes, collects and sells condensate and compresses the gas to sales pressures in six central compressors. The gas then goes to our plant which provides refrigerated liquid recovery to a negative 20 degrees Fahrenheit. The NGLs recovered are trucked to third-party facilities for fractionation and delivery to market.

Current throughput at the processing plant is 16-18 MMcf/d and sufficient capacity remains for additional large-scale development drilling.

Marketing Arrangements

We market crude oil, natural gas, NGLs and electricity.

Crude Oil. Approximately 81% of our California crude oil production is connected to California markets via crude oil pipelines. We generally do not transport, refine or process the crude oil we produce and do not have any long-term crude oil transportation arrangements in place. California oil prices are Brent-influenced as California refiners import more than 50% of the state's demand from foreign sources. This dynamic has led to periods where the price for the primary benchmark, Midway-Sunset, a 13° API heavy crude, has been equal to or exceeded the price for WTI, a light 40° API crude. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low transportation costs, coupled with Brent-influenced pricing, will allow us to continue to realize strong cash margins in California. Our oil production is primarily sold under market-sensitive contracts that are typically priced at a differential to purchaser-posted prices for the producing area. As of September 30, 2018, all of our oil production was sold under short-term contracts. The waxy quality of oil in Utah has historically limited sales primarily to the Salt Lake City market, which is largely dependent on the supply and demand of oil in the area. The recent success of a tight oil play in the basin has increased supply and put downward pressure on physical oil prices. Due to these circumstances, we are endeavoring to sell our crude to markets outside the basin. Export options to other markets via rail are available and have been used in the past, but are comparatively expensive.

Natural Gas. Our natural gas production is primarily sold under market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area. Our natural gas production is sold to purchasers under seasonal spot price or index contracts. Although exact percentages vary daily, as of September 30, 2018, all of our natural gas and NGLs production was sold under short-term contracts at market-sensitive or spot prices. In certain circumstances, we have entered into natural gas processing contracts whereby the residual natural gas is sold under short-term contracts but the related NGLs are sold under long-term contracts. In all such cases, the residual natural gas and NGLs are sold at market-sensitive index prices.

NGLs. We do not have long-term or long-haul interstate NGLs transportation agreements. We sell substantially all of our NGLs to third parties using market-based pricing. Our NGL sales are generally pursuant to processing contracts or short-term sales contracts. The relatively small volumes of condensate produced in Colorado are sold under market-based short-term contracts.

Electricity. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce field operating costs, a significant share is sold into the California market. Excess electric output and associated electric products are marketed to third parties and offered daily into the California electric market to be dispatched based on pricing and grid requirements.

Electricity

Generation. Our cogeneration facilities generate both electricity and steam for our properties and electricity for off lease sales. The total electrical generation capacity of three of our five cogeneration facilities, which are centrally located on certain of our oil producing properties, is approximately 90 MW. Our other two, and newest, cogeneration facilities came on line in the third quarter of 2017 with a capacity of approximately 10 MW. The steam generated by each facility is capable of being delivered to numerous wells that require steam for our EOR processes. The main purpose of the cogeneration facilities is to reduce the steam costs in our heavy oil operations and to secure operating control of our steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators.

Cogeneration costs are allocated between electricity generation and oil and natural gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of our power contracts.

Sales Contracts. We sell electricity produced by three of our cogeneration facilities under long-term contracts approved by the California Public Utilities Commission (the "CPUC") to two California investor-owned utilities, Southern California Edison Company ("Edison") and Pacific Gas and Electric Company ("PG&E"). The following summarizes the contracts for the three facilities.

- *Cogen 18 facility*: Our Public Utilities Regulatory Policy Act of 1978, as amended ("PURPA"), PPA with PG&E became effective on October 1, 2012, and has a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it continues to be eligible for PPAs pursuant to PURPA. Under such PPA, we are paid the CPUC-determined short run avoidance cost energy price and a combination of firm and "as-available" capacity payments.

- *Cogen 42 facility*: Pursuant to a competitive solicitation, our request for offers ("RFO") PPA with Edison became effective on July 1, 2014 and has a term of seven years. Under such PPA, we are paid a negotiated energy and capacity price stipulated in the contract.

- *Cogen 38 facility*: Our legacy PPA expired in March 2012, at which time a transition PPA with PG&E became effective. We participated in a competitive solicitation, which resulted in the execution of a RFO PPA with Edison that became effective on July 1, 2015, and has a term of seven years. Under such PPA, we are paid a negotiated energy and capacity price stipulated in the contract.

Electricity and steam produced from our Pan Fee and 21Z CoGens facilities are used solely for field operations with one facility being run at a time and the other as 100% backup. For more information, see "Risk Factors—Risks Related to Our Business and Industry—We are dependent on our cogeneration facilities to produce steam for our operations. Viable contracts for the sale of surplus electricity, economic market prices and regulatory conditions affect the economic value of these facilities to our operations."

The following table sets forth information regarding our cogeneration facilities and contracts for the three months ended September 30, 2018:

Facility	Type of Contract	Purchaser	Contract Expiration	Approximate MW Available for Sale	Approximate MW Consumed in Operations	Approximate Barrels of Steam Per Day for the three months ended September 30, 2018
Cogen 18	PURPA	PG&E	Sept. 2019	9.7	6.1	6,925
Cogen 42	RFO	Edison	June 2021	37.7	2.7	14,089
Cogen 38	RFO	Edison	June 2022	32.6	0.7	13,277
21Z Cogen	N/A	N/A	N/A	N/A	4.3	2,188
Pan Fee Cogen[(1)]	N/A	N/A	N/A	N/A	0.6	145

(1) Pan Fee Cogen is used as the 100% backup to 21Z Cogen. When 21Z Cogen is not running, the electricity generation and steam are produced at the Pan Fee Facility.

Principal Customers

For the ten months ended December 31, 2017, Andeavor, Phillips 66 and Kern Oil & Refining accounted for approximately 37%, 34% and 15%, respectively, of our oil, natural gas and NGL sales. For the two months ended February 28, 2017, sales of oil, natural gas and NGLs to Andeavor and Phillips 66 accounted for approximately 36% and 31%, respectively, of our sales. For the year ended December 31, 2016, Andeavor and Phillips 66 accounted for approximately 34% and 28%, respectively, of our oil, natural gas and NGL sales. For the years ended December 31, 2017, including the successor and predecessor periods, and 2016, 100% of electricity sales were attributable to PG&E and Edison.

At September 30, 2018, trade accounts receivable from two customers represented approximately 40% and 22% of our receivables. At December 31, 2017, trade accounts receivable from two customers represented approximately 35% and 26% of our receivables. At December 31, 2016, trade accounts receivable from two customers represented approximately 29% and 21% of our receivables.

If we were to lose any one of our major oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of our oil and natural gas in that particular purchaser's service area and it could have a detrimental effect on the prices and volumes of oil, natural gas and NGLs that we are able to sell.

Our Reserves and Production Information

Reserve Data

The following table summarizes our estimated proved reserves and related PV-10 using SEC Pricing as of December 31, 2017 and Strip Pricing as of May 31, 2018. The reserve estimates presented in the table below are based on reports prepared by DeGolyer and MacNaughton. The SEC Pricing reserve estimates were prepared in accordance with current SEC rules and regulations regarding oil, natural gas and NGL reserve reporting and Strip Pricing data was prepared using closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018. Reserves are stated net of applicable royalties.

	SEC Pricing as of December 31, 2017(1)					Strip Pricing as of May 31, 2018(2)				
	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin(3)	Total	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin(3)	Total
Proved developed reserves:										
Oil (MMBbl)	61	7	—	—	68	63	7	—	—	70
Natural Gas (Bcf)	—	47	42	12	100	—	41	17	9	67
NGLs (MMBbl)	—	1	—	—	1	—	1	—	—	1
Total (MMBoe)(4)(5)	61	16	7	2	86	63	15	3	2	82
Proved undeveloped reserves(7):										
Oil (MMBbl)	32	—	—	—	32	32	—	—	—	32
Natural Gas (Bcf)	—	—	137	—	137	—	—	—	—	—
NGLs (MMBbl)	—	—	—	—	—	—	—	—	—	—
Total (MMBoe)(5)	32	—	23	—	55	32	—	—	—	32
Total proved reserves:										
Oil (MMBbl)	93	7	—	—	101	95	7	—	—	102
Natural Gas (Bcf)	—	47	179	12	237	—	41	17	9	67
NGLs (MMBbl)	—	1	—	—	1	—	1	—	—	1
Total (MMBoe)(5)	93	16	30	2	141	95	15	3	2	115
PV-10 ($MM)(6)	998	84	24	7	1,114	1,762	91	4	5	1,862

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX (HH) for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate, $28.25 per barrel of NGL and $2.935 per thousand cubic feet of gas. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules including adjustments by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. For more information regarding commodity price risk, please see "Risk Factors—Risks Related to Our Business and Industry—Oil, natural gas and NGL prices are volatile and directly affect our results."

(2) Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (HH) for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance.

Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip

Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX (HH). The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00.

We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves.

The decrease in reserve volumes using Strip Pricing as opposed to SEC Pricing is primarily the result of lower realized gas prices in Colorado using Strip Pricing as of May 31, 2018.

(3) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

(4) Approximately 9% of proved developed oil reserves, 1% of proved developed NGLs reserves, 0% of proved developed natural gas reserves and 7% of total proved developed reserves are non-producing.

(5) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

(6) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "—PV-10." PV-10 does not give effect to derivatives transactions.

(7) Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.

PV-10

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Management believes that PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the Company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

The following table provides a reconciliation of PV-10 of our proved reserves to the standardized measure of discounted future net cash flows using SEC Pricing at December 31, 2017:

	At December 31, 2017 ($ in millions)
PV-10	$ 1,114
Less: present value of future income taxes discounted at 10%	(137)
Standardized measure of discounted future net cash flows	$ 977

GAAP does not prescribe any corresponding measure for PV-10 of reserves as of an interim date or on any basis other than SEC prices. As a result, it is not practicable for us to reconcile PV-10 using Strip Pricing as of May 31, 2018 to GAAP standardized measure.

Proved Undeveloped Reserves Additions

From December 31, 2016 to December 31, 2017, we had proved undeveloped reserve additions of 41 MMBoe from extensions and discoveries. At December 31, 2016, we had minimal proved undeveloped reserves due to the Chapter 11 Proceedings. Additions of proved undeveloped reserves reflect an increase from that minimal amount. In the third quarter of 2017, we completed the Hill Acquisition and the Hugoton Disposition. The Hill Acquisition accounted for an increase of 13 MMBoe of proved undeveloped reserves. The Hugoton Disposition did not affect our proved undeveloped reserves. The total changes to our proved undeveloped reserves from December 31, 2016 to December 31, 2017 were as follows:

	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin[2]	Hugoton basin	Total
Beginning balance at December 31, 2016 (MMBoe)[1]	—	—	—	—	—	—
Production (MMBoe)[1]	—	—	—	—	—	—
Revisions or reclassifications of previous estimates (MMBoe)[1]	—	—	—	—	—	—
Improved Recovery (MMBoe)[1]	—	—	—	—	—	—
Extensions and Discoveries (MMBoe)[1]	19	—	23	—	—	42
Purchases (MMBoe)[1]	13	—	—	—	—	13
Sales (MMBoe)[1]	—	—	—	—	—	—
Ending balance as of December 31, 2017 (MMBoe)[1]	32	—	23	—	—	55

(1) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

(2) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Extensions and Discoveries

Through 2017 we added 41 MMBoe of proved reserves from extensions and discoveries split between California and Colorado, supported by our recent development activity in both regions. This is up from the 0 MMBoe represented in the December 31, 2016 reserves report which was due to Linn Energy’s decision not to commit capital to the development of the fields at that time.

Reserves Evaluation and Review Process

Independent engineers, DeGolyer and MacNaughton, prepared our reserve estimates reported herein. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future production rates, future net revenue and the present value of such future net revenue, based in part on data provided by us. When preparing the reserve estimates, the independent engineering firm did not independently verify the accuracy and completeness of the information and data furnished by us with respect to ownership interests, production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of their work, something came to their attention that brought into question the validity or sufficiency of any such information or data, they did not rely on such information or data until they had satisfactorily resolved their related questions. The estimates of reserves conform to SEC guidelines, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years. Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost, operating expense and realized commodity revenue data.

The independent engineering firm also prepared estimates with respect to reserve categorization, using the definitions of proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

Our internal control over the preparation of reserve estimates is a process designed to provide reasonable assurance regarding the reliability of our reserve estimates in accordance with SEC regulations. The preparation of reserve estimates was overseen by Kurt Neher, who has a Masters in Geology from the University of South Carolina and a Bachelors in Geology from Carleton College, and more than 31 years of oil and natural gas industry experience. The reserve estimates were reviewed and approved by our senior engineering staff and management, and presented to our board of directors. Within DeGolyer and MacNaughton, the technical person primarily responsible for reviewing our reserves estimates was Gregory K. Graves, P.E. Mr. Graves is a Registered Professional Engineer in the State of Texas (License No. 70734), is a member of both the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers and has in excess of 33 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Graves graduated from the University of Texas at Austin in 1984 with a Bachelor of Science degree in Petroleum Engineering.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGLs that cannot be measured exactly. For more information, see “Risk Factors—Risks Related to Our Business and Industry—Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.”

Determination of Identified Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2017, we have approximately 790 gross (786 net) drilling locations attributable to our proved undeveloped reserves. We use production data and experience gained from our development programs to identify and prioritize this proven drilling inventory. These drilling locations are included in our inventory only after they have been evaluated technically and are deemed to have a high likelihood of being drilled within a five-year time frame. As a result of technical evaluation of geologic and engineering data, it can be estimated with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

Unproven Drilling Locations

We have also identified a multi-year inventory of 5,190 gross (4,814 net) drilling locations that are not associated with our proved undeveloped reserves but are specifically identified on a field by field basis considering the applicable geologic, engineering and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing and other performance factors. These drilling locations primarily include (i) infill drilling locations, (ii) additional locations due to field extensions or (iii) potential IOR and EOR project expansions, some of which are currently in the pilot phase across our properties, but have yet to be moved to the proven category. We believe the assumptions and data used to estimate these drilling locations are consistent with established industry practices based on the type of recovery process we are using.

We plan to analyze our acreage for exploration drilling opportunities at appropriate levels. We expect to use internally generated information and proprietary models consisting of data from analog plays, 3-D seismic data, open hole and mud log data, cores and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons.

Well Spacing Determination

Our well spacing determinations in the above categories of identified well locations are based on actual operational spacing within our existing producing fields, which we believe are reasonable for the particular recovery process employed (i.e., primary, waterflood and EOR). Spacing intervals can vary between various reservoirs and recovery techniques. Our development spacing can be less than one acre for a thermal steamflood development in California and greater than ten acres for a primary gas expansion development in our Piceance asset in Colorado.

Drilling Schedule

Our identified drilling locations have been scheduled as part of our current multi-year drilling schedule or are expected to be scheduled in the future. However, we may not drill our identified sites at the times scheduled or at all. We view the risk profile for our prospective drilling locations and any exploration drilling locations we may identify in the future as being higher than for our other proved drilling locations.

Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. For a discussion of the risks associated with our drilling program, see "Risk Factors—Risks Related to Our Business and Industry—We may not drill our identified sites at the times we scheduled or at all."

The table below sets forth our PUD locations as of December 31, 2017 and total identified drilling locations as of September 30, 2018.

	PUD Locations (Gross)		**Total Identified Drilling Locations (Gross)[2]**	
	Oil and Natural Gas Wells	**Injection Wells**	**Oil and Natural Gas Wells**	**Injection Wells**
California	549	161	4,991	1,134
Uinta basin	—	—	1,244	—
Piceance basin[1]	80	—	870	—
East Texas basin[3]	—	—	80	—
Total Identified Drilling Locations	629	161	7,185	1,134

(1) Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.
(2) Includes 3,386 Tier 1 gross drilling locations company-wide that we anticipate drilling over the next 5 to 10 years and 3,799 additional gross drilling locations that are currently under review.
(3) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Production and Operating Data

The following table sets forth information regarding production, realized and benchmark prices, and production costs (i) on a historical basis for the year ended December 31, 2016, the two months ended February 28, 2017, the seven months ended September 30, 2017, the ten months ended December 31, 2017 and the nine months ended September 30, 2018 and (ii) on a pro forma basis for the year ended December 31, 2017.

The pro forma information has been prepared to give pro forma effect to (i) the Plan and related transactions and fresh-start accounting and (ii) the Hugoton Disposition, as if each had been completed as of January 1, 2017, respectively. The summary unaudited pro forma financial information does not give effect to the Hill Acquisition because such transaction is not deemed significant under Rule 3-05 of the SEC's Regulation S-X, so it is not required to be presented herein. For more information, see "Prospectus Summary—Summary Historical and Pro Forma Financial Information."

For additional information regarding pricing dynamics, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Business Environment and Market Conditions."

	Pro Forma[4]	Berry Corp. (Successor)			Berry LLC (Predecessor)	
	Year Ended December 31, 2017	Nine Months Ended September 30, 2018	Ten Months Ended December 31, 2017	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Production Data[5]:						
Oil (MBbl/d)	20.5	21.5	20.6	20.0	19.5	23.1
Natural gas (MMcf/d)	31.2	27.7	49.4	57.2	71.7	78.1
NGLs (MBbl/d)	0.6	0.6	2.0	2.6	5.2	3.6
Average daily combined production (MBoe/d)[1]	26.3	26.7	30.9	32.1	36.7	39.7
Oil (MBbl)	7,471	5,867	6,318	4,288	1,153	8,463
Natural gas (MMcf)	11,382	7,555	15,119	12,241	4,232	28,577
NGLs (MBbl)	216	157	605	552	304	1,307
Total combined production (MBoe)[1]	9,584	7,284	9,443	6,880	2,162	14,533
Weighted average realized prices:						
Oil with hedges (per Bbl)	$ 48.37	$ 57.96	$ 48.53	$ 47.17	$ 47.40	$ 36.88
Oil without hedges (per Bbl)	$ 47.89	$ 65.97	$ 48.05	$ 44.87	$ 46.94	$ 35.83
Natural gas (per Mcf)	$ 2.82	$ 2.44	$ 2.70	$ 2.69	$ 3.42	$ 2.31
NGLs (per Bbl)	$ 20.00	$ 28.93	$ 22.23	$ 21.67	$ 18.20	$ 17.67
Average Benchmark prices:						
Oil (Bbl) – Brent	$ 54.82	$ 72.67	$ 54.65	$ 51.70	$ 55.72	$ 45.00
Oil (Bbl) – WTI	$ 50.95	$ 66.75	$ 50.53	$ 48.45	$ 53.04	$ 43.32
Natural gas (MMBtu) – HH	$ 3.11	$ 2.90	$ 3.00	$ 3.03	$ 3.66	$ 2.46
Average costs per Boe[2]:						
Lease operating expenses	$ 17.92	$ 18.87	$ 15.84	$ 15.26	$ 13.06	$ 12.73
Electricity generation expenses	1.89	1.90	1.58	1.48	1.48	1.18
Electricity sales	(2.67)	(3.53)	(2.33)	(2.26)	(1.69)	(1.60)
Transportation expenses	1.61	1.05	2.04	2.71	2.86	2.86
Transportation sales[2]	—	(0.07)	—	—	—	—
Marketing expenses	0.31	0.20	0.25	0.24	0.30	0.21
Marketing revenues	(0.35)	(0.25)	(0.29)	(0.28)	(0.29)	(0.25)
Total operating expenses	$ 18.71	$ 18.17	$ 17.09	$ 17.15	$ 15.72	$ 15.13
General and Administrative Expenses[3]	$ 6.54	$ 5.20	$ 5.93	$ 6.33	$ 3.68	$ 5.45
Depreciation, depletion and amortization	$ 7.91	$ 8.51	$ 7.25	$ 7.03	$ 13.02	$ 12.26
Taxes, other than income taxes	$ 3.61	$ 3.47	$ 3.62	$ 3.65	$ 2.41	$ 1.73

(1) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

(2) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to-date.

(3) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of approximately $2.77, $3.40, $1.22, $4.12 and none per Boe for the pro forma year ended December 31, 2017, the ten months ended December 31, 2017, the nine months ended September 30, 2018, the seven months ended September 30, 2017 and the two months ended February 28, 2017, respectively.

(4) Does not include the effects of the Hill Acquisition. We estimate that the additional production associated with the Hill Acquisition for the year ended December 31, 2017 was approximately 637,000 Boe or 1,745 Boe/d.

(5) Production represents volumes sold during the period.

The following tables sets forth information regarding production volumes for fields with equal to or greater than 15% of our total proved reserves for each of the periods indicated:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Hugoton basin Field[1]			
Total production[2]**:**			
Oil (MBbls)	*	*	—
Natural gas (Bcf)	*	*	14.6
NGL (MBbls)	*	*	1,020
Total (MBoe)[3]	*	*	3,457

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
SJV South Midway Field			
Total production[2]**:**			
Oil (MBbls)	1,963	369	2,477
Natural gas (Bcf)	—	—	—
NGL (MBbls)	—	—	—
Total (MBoe)[3]	1,963	369	2,477

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
SJV Belridge Hill			
Total production[2]**:**			
Oil (MBbls)	609	35	*
Natural gas (Bcf)	—	—	*
NGL (MBbls)	—	—	*
Total (MBoe)[3]	609	35	*

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Piceance			
Total production[2]**:**			
Oil (MBbls)	14	2	*
Natural gas (Bcf)	3.6	0.8	*
NGL (MBbls)	—	—	*
Total (MBoe)[3]	610	138	*

* Represented less than 15% of our total proved reserves for the periods indicated.
(1) On July 31, 2017, we sold our approximately 78% non-operated working interest in the Hugoton natural gas field. No production data is available for periods following the disposition.
(2) Production represents volumes sold during the period.
(3) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the

corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

Productive Wells

As of December 31, 2017, we had a total of 3,721 gross (3,602 net) producing wells (including 469 gross and net steamflood and waterflood injection wells), approximately 90% of which were oil wells. Our average working interests in our producing wells is approximately 95%. Many of our oil wells produce associated gas and some of our gas wells also produce condensate and NGLs.

The following table sets forth our productive oil and natural gas wells (both producing and capable of producing) as of December 31, 2017.

	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin(3)	Total
Oil					
Gross(1)	2,522	912	—	—	3,434
Net(2)	2,497	867	—	—	3,364
Gas					
Gross(1)	—	—	170	117	287
Net(2)	—	—	122	116	238

(1) The total number of wells in which interests are owned. Includes 469 steamflood and waterflood injection wells in California. Excludes eleven wells in the Permian basin all with less than 0.1% working interest and 91 wells in the Piceance basin each with a 5% working interest.
(2) The sum of fractional interests.
(3) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2017. Approximately 75% of our leased acreage was held by production at December 31, 2017.

	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin(5)	Total
			($ in thousands)		
Developed(1)					
Gross(2)	10,800	93,763	9,260	5,853	119,676
Net(3)	7,865	69,530	6,780	4,533	88,708
Undeveloped(4)					
Gross(2)	80	49,357	1,293	—	50,730
Net(3)	80	29,274	1,228	—	30,582

(1) Acres spaced or assigned to productive wells.
(2) Total acres in which we hold an interest.
(3) Sum of fractional interests owned based on working interests or interests under arrangements similar to production sharing contracts.
(4) Acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the acreage contains proved reserves.
(5) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Participation in Wells Being Drilled

The following table sets forth our participation in wells being drilled as of December 31, 2017.

	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin(1)	Total
Development wells					
Gross	2	—	—	—	2
Net	2	—	—	—	2
Exploratory wells					
Gross	—	—	—	—	—
Net	—	—	—	—	—

(1) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

At December 31, 2017, we were participating in 14 steamflood and waterflood pressure maintenance projects. Twelve steamflood projects and one waterflood project were located in the San Joaquin basin, and one waterflood project was located in the Uinta basin.

Drilling Activity

The following table shows the net development wells we drilled during the periods indicated. We did not drill any exploratory wells during the periods presented. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. 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.

	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin(3)	Total
2017					
Oil(2)	124	—	—	—	124
Natural Gas	—	—	—	—	—
Dry	—	—	—	—	—
2016					
Oil(1)	11	—	—	—	11
Natural Gas	—	—	—	—	—
Dry	—	—	—	—	—

(1) Includes injector wells.
(2) Includes 23 drilled uncompleted wells and 8 wells that had not yet been connected to gathering systems.
(3) On November 30, 2018, we sold our non-core oil and gas properties and related assets located in the East Texas Basin.

Delivery Commitments

We have made commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. For oil, these commitments are limited to lease production and do not have set volumes. As of December 31, 2017, 17,539 MMBtu/d of gas were contracted to be delivered under gas contracts with fixed volumes including 12,359 MMBtu/d in Utah and 5,000 MMBtu/d in Texas. Our Texas delivery commitments were transferred in conjunction with the sale of our non-core oil and gas properties in the East Texas Basin, which was completed on November 30, 2018. None of these commitments in any given year is expected to have a material impact on our financial statements.

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 at the time of acquisition. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. We do not commence drilling operations on a property until we have cured known title defects on such property that are material to the project. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations, or net profits interests.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and master limited partnerships in acquiring properties, contracting for drilling and other related services, and securing trained personnel. We also are affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our drilling program. Unlike a typical resource play, the lower-cost, commoditized nature of our equipment and service providers allows for relative insulation from the cost inflation pressures experienced by producers in unconventional plays. For more information regarding competition and the related risks in the oil and natural gas industry, please see “Risk Factors—Risks Related to Our Business and Industry—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.”

Operating Hazards and Insurance

The oil and natural gas industry involves a variety of operating hazards and risks that could result in substantial losses from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties, and suspension of operations. We may be liable for environmental damages caused by previous owners of property we purchase and lease. As a result, we may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate funds otherwise available, or result in the loss of properties. In addition, we may participate in wells on a non-operated basis and therefore may be limited in our ability to control the risks associated with the operation of such wells.

In accordance with customary industry practices, we maintain insurance against some, but not all, potential losses. We cannot provide assurance that any insurance we obtain will be adequate to cover our losses or liabilities. We have elected to self-insure for certain items for which we have determined 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 not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. For more information about potential risks that could affect us, see “Risk Factors—Risks Related to Our Business and Industry—We may incur substantial losses and be subject to substantial liability claims as a result of catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.”

Seasonality

Seasonal weather conditions can impact a portion of our drilling and production activities. These seasonal conditions can occasionally pose challenges in our Utah and Colorado operations for meeting well-drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires.

Natural gas prices can fluctuate based on seasonal impacts. We purchase significantly more gas than we sell in order to generate steam in our cogeneration facilities for our producing activities. As a result, our key exposure to gas prices is in our costs. We effectively mitigate this exposure by selling excess electricity from our cogeneration operations to third parties. The pricing of these electricity sales is closely tied to the purchase price of natural gas.

Regulation of Health, Safety and Environmental Matters

Our operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and natural gas industry. These laws and regulations may:

- Establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, and attainment plans to meet those regional standards, which may significantly restrict development, economic activity and transportation in the region;

- require the acquisition of various permits before drilling, workover production, underground fluid injection, enhanced oil recovery methods, or waste disposal commences;

- require notice to stakeholders of proposed and ongoing operations;

- require the installation of expensive safety and pollution control equipment—such as leak detection, monitoring and control systems—to prevent or reduce the release or discharge of regulated materials into the air, land, surface water or groundwater;

- restrict the types, quantities and concentration of various regulated materials, including oil, natural gas, produced water or wastes, that can be released into the environment in connection with drilling and production activities, and impose energy efficiency or renewable energy standards on us or users of our products and services;

- limit or prohibit drilling activities on lands located within coastal, wilderness, wetlands, groundwater recharge or endangered species inhabited areas, and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources, and require the dedication of surface acreage for habitat conservation;

- establish waste management standards or require remedial measures to limit pollution from former operations, such as pit closure, reclamation and plugging and abandonment of wells or decommissioning of facilities;

- impose substantial liabilities for pollution resulting from operations or for preexisting environmental conditions on our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;

- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state, and private lands or leases, including preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

For example, in 2014, DOGGR began a detailed review of the multi-decade practice of permitting underground injection wells under the Safe Drinking Water Act (“SDWA”). The purpose of the review was to ensure that wastewater is not injected into formations that could be a future source of drinking water supply. In 2015, the state set deadlines to obtain EPA’s confirmation of aquifer exemptions under the SDWA in certain formations in certain fields. Several industry groups challenged DOGGR’s implementation of its aquifer exemption regulations, and, in March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcements of DOGGR’s aquifer exemption regulations. The court held that DOGGR must show that an underground injection well's operations have caused an actual harm and go through a hearing process before the agency can issue fines or shut down operations.

In addition, DOGGR has proposed new underground injection regulations in July 2018. The proposed rules would impose additional requirements related to injection approvals, project data requirements, mechanical integrity testing of injection wells, monitoring requirements, prevention of surface expressions, incident response, and monitoring seismic activity. To date, restrictions on underground injection have not affected our oil and natural gas production in any material way. Separately, the state began a review in 2015 of permitted surface discharge of produced water, which led to additional permitting requirements in 2017 for surface discharge of produced water. Government authorities may ultimately restrict injection of produced water or other fluids in additional formations or certain wells, restrict the surface discharge or use of produced water or take other administrative actions. The foregoing reviews could also give rise to litigation with government authorities and third parties.

These laws, rules and regulations may also restrict the production rate of oil, natural gas and NGL below the rate that would otherwise be possible. The regulatory burden on the industry increases the cost of doing business and consequently may have an adverse effect upon capital expenditures, earnings or competitive position. Violations and liabilities with respect to these laws and regulations could result in significant administrative, civil, or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and prospects. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on operating costs.

The environmental laws and regulations applicable to us and our operations include, among others, the following U.S. federal laws and regulations:

- CAA, which governs air emissions;
- Clean Water Act ("CWA"), which governs discharges to and excavations within the waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), which imposes liability where hazardous substances have been released into the environment (commonly known as "Superfund");
- The Oil Pollution Act of 1990, which amends and augments the CWA and imposes certain duties and liabilities related to the prevention of oil spills and damages resulting from such spills;
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- National Environmental Policy Act ("NEPA"), which requires careful evaluation of the environmental impacts of oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste;
- SDWA, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which regulate oil and gas production activities on federal lands and impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGL, including imposing production taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of resources. States may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulations, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil, natural gas and NGL that may be produced from our wells and to limit the number of wells or locations we can drill. The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal opportunity employment.

We believe that compliance with currently applicable environmental laws and regulations is unlikely to have a material adverse impact on our business, financial condition, results of operations or cash flows. Future regulatory issues that could impact us include new rules or legislation, or the reinterpretation of existing rules or legislation, relating to the items discussed below.

Climate Change

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted three sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles, a second that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs, and a third that regulates GHG emissions from fossil fuel-burning power plants, although future implementation of this rule as it applies to existing power plants is uncertain at this time due to ongoing litigation and reconsideration of the rule by the current administration.

The EPA and the California Air Resources Board ("CARB") have also expanded direct regulation of methane emissions. In June 2016, the EPA finalized rules that establish new controls for emissions of methane (a GHG considered more potent than carbon dioxide) from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. However, in March 2018 EPA finalized several amendments to the 2016 rule, including rolling back a requirement to repair leaking components during unplanned or emergency shutdowns. Also, in September 2018, the EPA issued proposed revisions to the 2016 methane rules, which would reduce the monitoring obligations for wells and compressor stations and exempting previously covered equipment at certain locations. Separately, the U.S. Bureau of Land Management ("BLM") previously finalized similar limitations on methane emissions from venting and flaring and leaking equipment from oil and natural gas activities on public lands, but issued a final rule repealing those standards in September 2018. Several states and environmental groups have announced their intent to file judicial challenges against any attempt to repeal or revise the EPA and BLM methane rules. As a result, future implementation of both the EPA and BLM methane rules is uncertain at this time.

Additionally, CARB has promulgated regulations regarding monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and gas production, pipeline gathering and boosting station assets, and natural gas processing plant operations beginning in 2018 and additional controls such as vapor recovery to capture methane emissions in subsequent years. Colorado has also imposed similar regulations governing methane emissions that could impact our operations in the Piceance basin.

In addition, on September 10, 2018, the Governor of California signed into law a bill that would commit California, the fifth largest economy in the world, to the use of 100-percent zero-carbon electricity by 2045. The same day, the Governor also signed an executive order committing California to total economy-wide carbon neutrality by 2045, including in transportation, building heating and cooling, and industry. The law does not directly affect the oil and gas industry, and it remains unclear what actions state agencies may take in response to executive order. In any event, these recent actions could result in decreased future demand for our products to meet energy needs and in turn have an adverse effect on our business and results of operations. Legislation and regulation to address climate change could also increase the cost of consuming, and thereby reduce demand for, oil, natural gas and other products produced by us, and potentially lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. In addition, several municipalities in California have filed tort lawsuits in California state court against numerous fossil fuel energy companies to address concerns such as coastal erosion and other alleged climate-related damage. Similarly, two counties in Colorado have filed suit against several fossil fuel energy companies, alleging climate-related damages.

In addition, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires 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. However, in 2017 the Trump administration indicated that the United States would be withdrawing from participation in the Paris Agreement. The United States’ adherence to the exit process is uncertain at this time. 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, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs, including 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. See “—California GHG Regulations” below for additional details on current GHG regulations in the State of California. 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 also adversely affect demand for the oil and natural gas we produce.

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, droughts, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations. For more information, please see “Risk Factors—Risks Related to Our Business and Industry—Concerns about climate change and other air quality issues may affect our operations or results;” and “—Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including well stimulation, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy.”

California GHG Regulations

In October 2006, California adopted the Global Warming Solutions Act of 2006, which established a statewide “cap and trade” program with an enforceable compliance obligation beginning with 2013 GHG emissions and ending in 2020. The state has also established a low carbon fuel standard that encourages the use of fuels with lower carbon intensities instead of traditional fossil fuels. In July 2017, California extended its cap and trade program through 2030. The program is designed to reduce the state’s GHG emissions to 1990 levels by 2020 and to reduce the state’s GHG emissions to at least 40% below 1990 levels by 2030. The California cap and trade program sets maximum limits or caps on total emissions of GHGs from industrial sectors of which we are a part, as our California operations emit GHGs. The cap will decline annually through 2030. We are required to remit compliance instruments for each metric ton of GHG that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Under the cap and trade program, we will be granted a certain number of California carbon allowances (“CCA”) and we will need to purchase CCAs and/or offset credits to cover the remaining amount of our emissions. Compliance with the California cap and trade program laws and regulations could significantly increase our capital, compliance and operating costs and could also reduce demand for the oil and natural gas we produce. The cost to acquire compliance instruments will depend on the market price for such instruments at the time they are purchased, the distribution of cost-free allowances among various industry sectors by the California Air Resources Board and our ability to limit our GHG emissions and implement cost-containment measures.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and natural gas regulatory programs. However, the EPA has asserted federal regulatory authority pursuant to the federal 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 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 also finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Further, in March 2015, the BLM adopted a rule requiring, among other things, public disclosure to the BLM of chemicals used in hydraulic fracturing operations after fracturing operations have been completed and would strengthen standards for well-bore integrity and management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. On December 29, 2017 the BLM formally rescinded the 2015 rule governing hydraulic fracturing operations on public and tribal lands. The 2015 rule included a comprehensive set of well-bore integrity requirements, standards for the interim storage of recovered waste fluids, mandatory notifications and waiting periods for key parts of the fracturing process, and chemical disclosure requirements. On January 24, 2018, California and a coalition of environmental and tribal groups each filed lawsuits in the Northern District of California to challenge BLM's rescission of the 2015 rule. If the rule is reinstated, the outcome of this litigation could materially impact our operations in the Uinta basin and other areas. In addition, from time to time legislation has been introduced before Congress that would provide for federal regulation of hydraulic fracturing and would require disclosure of the chemicals used in the fracturing process. If enacted, these or similar bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites and also increased costs to make wells productive.

There may be other attempts to further regulate hydraulic fracturing under the SDWA, the Toxic Substances Control Act and/or other regulatory mechanisms. In December 2016, the EPA released its final report on a wide ranging study on the effects of hydraulic fracturing on water resources. While no widespread impacts from hydraulic fracturing were found, the EPA identified a number of activities and factors that may have increased risk for future impacts.

Moreover, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise impose enhanced permitting, fluid disclosure, or well construction requirements on hydraulic fracturing activities. For example, many states in which we operate have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. In addition, the regulation or prohibition of hydraulic fracturing is the subject of significant political activity in a number of jurisdictions, some of which have resulted in tighter regulation (including, most recently, new regulations in California requiring a permit to conduct well stimulation), bans on fracturing in certain locations, and/or recognition of local government authority to implement such restrictions. Many of these restrictions are being challenged in court cases. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations or otherwise impact the value of our assets. In addition, any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect our revenues, results of operations and net cash provided by operating activities.

We use water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water or dispose of or recycle water used in our drilling and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including but not limited to produced water, drilling fluids and other wastes associated with the development or production of natural gas.

The SDWA and the Underground Injection Control ("UIC") Program

The SDWA and the UIC program promulgated under the SDWA and relevant state laws regulate the drilling and operation of disposal wells that manage produced water (brine wastewater containing salt and other contaminants produced by natural gas and oil wells). The EPA directly administers the UIC program in some states, and in others administration is delegated to the state. Permits must be obtained before developing and using deep injection wells for the disposal of produced water, and well casing integrity monitoring must be conducted periodically to ensure the well casing is not leaking produced water to groundwater. Contamination of groundwater by natural gas and oil drilling, production and related operations may result in fines, penalties, remediation costs and natural resource damages, among other sanctions and liabilities under the SDWA and other federal and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for groundwater contamination, alternative water supplies, property impacts and bodily injury.

Solid and Hazardous Waste

Although oil and natural gas wastes generally are exempt from regulation as hazardous wastes under the federal RCRA and some comparable state statutes, it is possible some wastes we generate presently or in the future may be subject to regulation under the RCRA or other similar statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including hazardous wastes and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. For example, in December 2016, the EPA and several environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as a hazardous waste under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Were the EPA to propose a rulemaking, the consent decree requires that EPA take final action by no later than July 15, 2021. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the costs to manage and dispose of generated wastes.

In addition, the federal CERCLA can impose joint and several liability without regard to fault or legality of conduct on classes of persons who are statutorily responsible for the release of a hazardous substance into the environment. These persons can include the current and former owners or operators of a site where a release occurs, and anyone who disposes or arranges for the disposal of a hazardous substance released at a site. Under CERCLA, such persons may be subject to strict, joint and several liability for the entire cost of cleaning up hazardous substances that have been released into the environment and for other costs, including response costs, alternative water supplies, damage to natural resources and for the costs of certain health studies. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Each state also has environmental cleanup laws analogous to CERCLA. Petroleum hydrocarbons or wastes may have been previously handled, disposed of, or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. These properties and any materials disposed or released on them may subject us to liability under CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, to contribute to remediation costs, or to perform remedial activities to prevent future environmental harm.

Endangered Species Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. Some of our operations may be located in areas that are designated as habitats for endangered or threatened species. In February 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, the U.S. Fish and Wildlife Service continues its effort to make listing decisions and critical habitat designations where necessary for over 250 species, as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia. The U.S. Fish and Wildlife Service agreed to complete the review by the end of the agency's 2017 fiscal year. The agency missed the deadline but continues to review species for listing under the ESA. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The federal government in the past has pursued enforcement actions against oil and natural gas companies under the Migratory Bird Treaty Act after dead migratory birds were found near reserve pits associated with drilling activities. However, in December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the Migratory Bird Treaty Act. Various environmental groups have filed lawsuits challenging this opinion. The ESA has not previously had a significant impact on our operations. Nevertheless, the designation of previously unprotected species as being endangered or threatened could cause us to incur additional costs or become subject to operating restrictions in areas where the species are known to exist. If a portion of any area where we operate were to be designated as a critical or suitable habitat, it could adversely impact the value of our assets.

Air Emissions

The CAA and comparable state laws restrict the emission of air pollutants from many sources (e.g., compressor stations), through the imposition of air emission standards, construction and operating permitting programs and other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of 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. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 to 70 parts per billion. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standard, and separately, in December 2017, issued responses to state recommendations for designating non-attainment areas. In April 2018, the EPA issued final attainment status designations for most of the remaining portions of the United States.

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. 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. In addition, the EPA has adopted new rules under the CAA that require the reduction of volatile organic compound and methane emissions from certain fractured and refractured oil and 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.

In addition, the regulations place new requirements to detect and repair volatile organic compound and methane at certain well sites and compressor stations. In May 2016, the EPA also 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 the costs of development, which costs could be significant.

NEPA

Oil and natural gas exploration and production activities on federal lands are subject to NEPA. NEPA requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Water Resources

The CWA and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the CWA, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. Pursuant to these laws and regulations, we may be required to develop and implement spill prevention, control and countermeasure plans, ("SPCC plans") in connection with on-site storage of significant quantities of oil. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit from the U.S. Army Corps of Engineers. The process for obtaining permits has the potential to delay our operations. SPCC plans and other federal requirements require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. Also, in June 2016, the EPA finalized new wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly owned treatment works.

In August 2015, the EPA and U.S. Army Corps of Engineers issued a rule expanding the scope of the federal jurisdiction over wetlands and other types of waters (the "Clean Water Rule"). Currently, the Clean Water Rule and the scope of federal jurisdiction under the CWA are the subject of several legal challenges, and implementation of the rule has been blocked in some states. The EPA is also considering revising the scope of the 2015 rule, but any changes to the rule are likely to face judicial challenges from certain states and environmental groups. At this time we cannot predict how the original 2015 rule will be revised or whether it will be fully implemented as originally finalized. To the extent any final rule expands the range of properties subject to the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining dredge and fill activity permits in wetland areas, which could materially impact our operations in the San Joaquin basin and other areas.

Natural Gas Sales and Transportation

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. 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, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

FERC requires certain participants in the natural gas market, including natural gas gatherers and marketers which engage in a minimum level of natural gas sales or purchases, to submit annual reports regarding those transactions to FERC. Should we fail to comply with this requirement or any other applicable FERC-administered statute, rule, regulation or order, it could be subject to substantial penalties and fines.

Federal Energy Regulation

The enactment of the PURPA and the adoption of regulations thereunder by the FERC provided incentives for the development of cogeneration facilities such as those we own. A domestic electricity generating project must be a

Qualifying Facility ("QF") under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs and entities that own QFs generally are relieved of compliance with certain federal regulations pursuant to the Public Utility Holding Company Act of 2005. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a nondiscriminatory basis. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. Effective November 23, 2011, the California utility companies have been relieved of their PURPA obligation to enter into new contracts with cogeneration QFs larger than 20 MW. While the California utility companies are still required to enter into new contracts with smaller facilities, such as our Cogen 18 facility, there is no assurance that we will be able to secure new contracts upon the expiration of the existing contracts for our larger facilities. Even if new contracts are available for our larger facilities, there is no assurance that the prices and terms of such contracts will not adversely affect our financial condition, results of operations and net cash provided by operating activities.

State Energy Regulation

The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements between electric utilities and independent electricity producers, such as us, are under the regulatory purview of the CPUC. While we are not subject to direct regulation by the CPUC, the CPUC's implementation of PURPA and its authority granted to the investor-owned utilities to enter into other PPAs are important to us, as is other regulatory oversight provided by the CPUC to the electricity market in California. The CPUC's implementation of PURPA may be subject to change based on past and future determinations by the courts, or policy determinations made by the CPUC.

Operations on Indian Lands

A portion of our leases and drill-to-earn arrangements in the Uinta basin operating area and some of our future leases in this and other operating areas may be subject to laws promulgated by an Indian tribe with jurisdiction over such lands. In addition to potential regulation by federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations may apply to lessees, operators and other parties on Indian lands, tribal or allotted. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, tribal employment and contractor preferences and numerous other matters. Further, lessees and operators on Indian lands may be subject to the jurisdiction of tribal courts, unless there is a specific waiver of sovereign immunity by the relevant tribe allowing resolution of disputes between the tribe and those lessees or operators to occur in federal or state court.

These laws, regulations and other issues present unique risks that may impose additional requirements on our operations, cause delays in obtaining necessary approvals or permits, or result in losses or cancellations of our oil and natural gas leases, which in turn may materially and adversely affect our operations on Indian lands.

Pipeline Safety Regulations

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates safety of oil and natural gas pipelines, including, with some specific exceptions, oil and natural gas gathering lines. From time to time, PHMSA, the courts or Congress may make determinations that affect PHMSA's regulations or their applicability to our pipelines. These determinations may affect the costs we incur in complying with applicable safety regulations.

Worker Safety

The Occupational Safety and Health Act of 1970 ("OSHA") and analogous state laws regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties.

Future Impacts and Current Expenditures

We cannot predict how future environmental laws and regulations may impact our properties or operations. For the year ended December 31, 2017, including successor and predecessor periods, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. We are not aware of any environmental issues or claims that will require material capital expenditures during 2018 or that will otherwise have a material impact on our financial position, results of operations or cash flows.

Legal Proceedings

Substantially all of the Company's liabilities existing as of May 11, 2016, the petition date for the Company's Chapter 11 Proceedings, were repaid or restructured under the Plan. Please see "Pro Forma Financial Data—Plan of Reorganization and Fresh-Start Accounting" for more detailed information regarding the Plan and the treatment of claims under the Plan.

We are involved in various legal and administrative proceedings in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

For additional information regarding legal proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Lawsuits, Claims, Contingencies and Contractual Obligations."

Employees

As of December 31, 2017, we had 278 employees. Prior to our emergence from bankruptcy, the employees of Linn Operating, Inc. ("Linn Operating") provided services and support to us in accordance with an agency agreement and power of attorney between us and Linn Operating.

Corporate Information

We were incorporated in Delaware in February 2017. We have executive offices located at 5201 Truxtun Ave., Bakersfield, California 93309 and at 16000 N. Dallas Pkwy, Ste. 500, Dallas, Texas 75248, where we have our principal executive offices. Our telephone number is (661) 616-3900 and our web address is *www.berrypetroleum.com*. Information contained in or accessible through our website is not, and should not be deemed to be, part of this prospectus.

MANAGEMENT

The following sets forth information regarding our officers as of November 29, 2018:

Name	Age	Position
A. T. "Trem" Smith*	63	President and Chief Executive Officer, and Director
Cary Baetz*	54	Executive Vice President and Chief Financial Officer, and Director
Gary A. Grove*	58	Executive Vice President and Chief Operating Officer
Kurt Neher	57	Executive Vice President, Business Development
Kendrick F. Royer	54	Executive Vice President, Corporate Secretary and General Counsel

* Executive Officers

A. T. "Trem" Smith has served as the President, Chief Executive Officer and a director since March 2017. Prior to being named Chief Executive Officer, Mr. Smith began an informal consulting relationship in May 2016, followed by a formal consulting relationship later in October 2016, and then served as interim CEO while he was a consultant in January 2017. Mr. Smith has over 35 years of experience in the oil and gas industry. In January 2014, Mr. Smith founded TS&J Consulting, where he served until joining Berry Corp. in March 2017, which focused on providing consulting services to distressed companies and assets in the United States and United Kingdom. From January 2007 until January 2014, Mr. Smith was President and Chief Executive Officer at Hillwood International Energy, L.P. and HKN Energy Ltd., which focused on discoveries and production in the United States and northern Iraq. Mr. Smith spent 25 years of his career at Chevron, from 1981 until 2006, where he served in a number of leadership positions with increasing responsibilities in Russia, Thailand and multiple locations in the United States, including La Habra and San Francisco, California. While at Chevron, Mr. Smith was exposed to all phases of the business, including production, operations, exploration, business development, M&A, finance and technology. Mr. Smith graduated magna cum laude from Amherst College with a major in Geology and Russian and received a Master's degree and PhD in Economic Geology from Pennsylvania State University.

The board of directors believes Mr. Smith's knowledge and breadth of experience in all phases of oil and gas exploration and production spanning a career of over 35 years, and strategic management of domestic and international oil and gas assets and operations brings important and valuable skills to the board of directors and us.

Cary Baetz has served as Executive Vice President, Chief Financial Officer and a director since May 2017. Mr. Baetz most recently served as Chief Financial Officer at Seventy Seven Energy Inc., a domestic oilfield services company, from June 2012 to April 2017 and as Treasurer of Seventy Seven Energy Inc. from June 2014 to April 2017. From November 2010 to December 2011, he served as Senior Vice President and Chief Financial Officer of Atrium Companies, Inc. and from August 2008 to September 2010, served as Chief Financial Officer of Boots & Coots International Well Control, Inc. From 2005 to 2008, Mr. Baetz served as Vice President of Finance, Treasurer and Assistant Secretary of Chaparral Steel Company. Prior to joining Chaparral, he had been employed since 1996 with Chaparral's parent company, Texas Industries Inc. From 2002 to 2005, he served as Director of Corporate Finance of Texas Industries Inc. Mr. Baetz has led the sale of three public companies; has successfully completed two public spin-offs; and raised almost $5 billion in capital. Mr. Baetz holds a Bachelor of Science degree in Finance and Accounting from Oklahoma State University and a Master of Business Administration degree from the University of Arkansas.

The board of directors believes that Mr. Baetz is well-qualified to serve on our board of directors because of his extensive public energy company experience across the financial, strategic planning and investor relations areas and in spin-offs.

Gary A. Grove has served as Executive Vice President and Chief Operating Officer since May 2017. Mr. Grove has over 35 years of experience in the oil and gas industry. Mr. Grove has served as President and Chief Executive Officer of his consulting firm Greyhaven Energy, LLC, from April 2014 to the present, providing strategic planning, technical and acquisition advisory services to oil and gas industry clients. After helping lead Bonanza Creek Energy, Inc. in its initial public offering in 2011, Mr. Grove served as a Director, Executive Vice President, Engineering and Planning and Chief Operating Officer of Bonanza Creek Energy from December 2011 to April 2014. He also served as Director, Executive Vice President and Chief Operating Officer of a number of Bonanza Creek Energy's predecessor companies from March 2003 to December 2011. Prior to joining the Bonanza Creek entities, Mr. Grove held various reservoir engineering and management positions with UNOCAL and Nuevo Energy. Mr. Grove graduated from Marietta College with a Bachelor of Science degree in Petroleum Engineering.

Kurt Neher has served as our Executive Vice President of Business Development since May 2017. Mr. Neher has over 30 years of diverse technical and commercial experience in the international and United States oil and gas exploration and production business with Shell, Occidental Petroleum ("Oxy"), and California Resources Corporation ("CRC"). Between December 2014 and May 2017, Mr. Neher held the position of Vice President of Business Development at CRC, in which he led the company's Business Development effort. Prior to joining CRC, Mr. Neher led Oxy's California-focused exploration team and production geoscience effort from January 2008 to November 2014. From 1994 to 2008, he worked in various roles at Oxy, including as Chief Geologist, Worldwide Exploration Manager and Exploration Vice President, Ecuador. From 1990 to 1994, Mr. Neher held a number of different positions with Shell's deepwater Gulf of Mexico group in New Orleans. Mr. Neher began his career in 1986 with Shell International in Houston. Mr. Neher has a Masters in Geology from the University of South Carolina and a Bachelors in Geology from Carleton College.

Kendrick F. Royer has served as our Executive Vice President and General Counsel since November 2017 and as Corporate Secretary since December 2017. Prior to joining us, Mr. Royer most recently served as Deputy General Counsel and Assistant Corporate Secretary of CRC, from December 2014 to November 2017. Prior to that he was Assistant General Counsel at Oxy from May 2004 to December 2014. Earlier in his career he served as Senior Vice President, General Counsel and Corporate Secretary at toy retailer FAO, Inc. He started his career with law firms O'Melveny and Myers, LLP and Milbank, Tweed, Hadley and McCloy, LLP. Mr. Royer graduated magna cum laude from Princeton University with a Bachelor of Science in Engineering degree and holds his Juris Doctor from Vanderbilt University Law School.

Board of Directors

The following sets forth information regarding our board of directors as of November 29, 2018.

Name	Age	Position
A. T. "Trem" Smith	63	President and Chief Executive Officer, and Director
Cary Baetz	54	Executive Vice President and Chief Financial Officer, and Director
Brent S. Buckley	46	Director (Chairman)
Anne L. Mariucci	61	Director
C. Kent Potter	72	Director
Eugene "Gene" Voiland	71	Director

Brent S. Buckley has served as a director since February 2017 and as Chairman of the board since June 2017. Mr. Buckley is a managing director with Benefit Street Partners, one of our principal stockholders, which he joined in September 2014. Prior to joining Benefit Street Partners, from February 2009 through September 2014, Mr. Buckley was engaged in personal business and devoting time to family matters. From March 2006 to February 2009, Mr. Buckley was a managing director at Centerbridge Partners. Prior to Centerbridge, Mr. Buckley worked in various roles at Deutsche Bank Securities and Merrill Lynch. Mr. Buckley received a Master of Arts from the University of Pennsylvania's Graduate School of Arts & Sciences and a Bachelor of Science from the Wharton School at the University of Pennsylvania.

The board of directors believes that Mr. Buckley's management, directorship and business experience and analytical skill in distressed credit and special situation investment activities bring important and valuable skills to the board of directors and us.

Anne L. Mariucci has served as a director since September 2018. Ms. Mariucci serves on the boards of several public, private and non-profit companies, including: Southwest Gas Corporation since 2006, where she is a member of the audit and compensation committees; CoreCivic, Inc. since 2011, where she is a member of the audit and risk committees; and Taylor Morrison Home Corp., since 2014, where she is a member of the audit committee and chairman of the compensation committee. She is also currently on the board of Banner Health, one of the nation's largest hospital/health care organizations, where she has served since 2015, chairs its audit committee and serves on its compensation committee. She has served as the General Partner of MFLP and related entities, a family office and investment entity in excess of ten years. Ms. Mariucci's deep corporate experience springs from a 30-year career in finance and real estate, primarily with Del Webb Corporation, where she served in a variety of capacities and ultimately as President before her retirement in 2004. In 2001, Del Webb merged with Pulte Corp, creating the nation's largest homebuilding company, and Ms. Mariucci became head of strategy for this Fortune 200 company. Ms. Mariucci also co-founded Inlign Capital Partners, a Phoenix-based private equity firm. She has held licenses as a CPA, NASD General Securities Principal, and NASD Financial Principal. Ms. Mariucci received her Bachelor's degree in Accounting and Finance from the University of Arizona, where she graduated Phi Kappa Phi.

The board of directors believes that Ms. Mariucci's background in corporate finance, together with her prior board experience brings important and valuable skills to the board of directors and us.

C. Kent Potter has served as a director since September 2018. Mr. Potter is currently a member of the board of directors and chairman of the audit committee of Polyus Gold PJSC, Russia's largest gold mining company, where he has served since 2016. He has served on the boards of directors of various chemical and mining companies including EuroChem Group AG, a global agrochemical producer from 2014 to 2017, where he was audit committee chair, and SUEK PLC, Russia's largest coal producer and exporter from 2013 to 2016, where he was an audit committee member. He previously served as the Executive Vice President and Chief Financial Officer of Lyondell Basell Industries from 2009 to 2011, where he was responsible for all financial and information technology activities. His extensive career in the energy industry began with nearly 30 years at Chevron Corporation, during which time Mr. Potter held various senior management positions and worked in planning, finance, and controllership management roles for Chevron throughout the United States and overseas, and was responsible for all financial functions of Chevron's international exploration and production operations. Mr. Potter received a Bachelor of Science in Engineering from the University of California, Berkeley, and a Master of Business Administration (with an emphasis in Accounting and Finance) from its School of Business.

The board of directors believes that Mr. Potter's extensive experience in the energy industry, together with his prior board experience brings important and valuable skills to the board of directors and us.

Eugene "Gene" Voiland has served as a director since June 2017. Mr. Voiland is Chairman of the Board and of the Audit Committee of Valley Republic Bank where he has served as a member of the bank's board of directors since 2008. He also maintains Voiland Enterprises LLC, an independent management consulting firm that he has used for periodic endeavors since 2007. Mr. Voiland is the retired President and Chief Executive Officer of Aera Energy LLC ("Aera"), where he served for more than 10 years, from 1997 to 2007. He has a long history in the energy industry, having worked over 28 years for Shell before his service at Aera. During his career with Shell, he worked as an engineer and manager throughout the United States. He also held senior management positions with Shell, having been appointed General Manager of Engineering and General Manager of Corporate Planning. Mr. Voiland is a board member of Saltchuk Resources, a transportation company. He is also a board member and past Chairman of the California State Chamber of Commerce. Mr. Voiland is a graduate of Washington State University with a Bachelor of Science in Chemical Engineering. He is a member of the WSU Foundation Board of Governors and the WSU Foundation Investment Committee.

The board of directors believes that Mr. Voiland's experience in the energy industry, including his experience integrating operations of two separate business cultures to form and run the successful and efficient operations of the Aera joint venture, as well as his experience running two highly regulated businesses in California, together with his prior board experience brings important and valuable skills to the board of directors and us.

Board Composition and Director Independence

Pursuant to the Plan, on the Effective Date, we entered into a stockholders agreement with members of an ad hoc group of holders of our Unsecured Notes (the “Ad Hoc Committee”), which we amended and restated in connection with the IPO (as amended and restated, the “Stockholders Agreement”). Under the Stockholders Agreement, we are required to take all necessary action to cause the following two individuals to be nominated for election as directors of Berry Corp.:

- the individual serving as our Chief Executive Officer; and

- one individual designated by Benefit Street Partners (for so long as Benefit Street Partners beneficially owns at least ten percent of the common stock beneficially owned by all of the parties to the Stockholders Agreement).

Benefit Street Partners has the right under the Stockholders Agreement to designate a director to fill any vacancy created by the resignation or removal of its designee. See “Description of Capital Stock—Stockholders Agreement.” The designee of Benefit Street Partners is currently Brent S. Buckley. Oaktree Capital Management also previously had the right to designate one individual for nomination for election as director, but effective September 12, 2018, Oaktree Capital Management relinquished this right under the Stockholders Agreement.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board’s ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the board to fulfill their duties. Our board of directors has determined that Messrs. Buckley, Potter and Voiland and Mrs. Mariucci are independent under applicable SEC and NASDAQ listing standards.

The Stockholders Agreement will terminate automatically on February 28, 2020. The Stockholders Agreement may be terminated earlier by written agreement between us and the members of the Stockholder Group (as defined in the Stockholders Agreement) owning at least a majority of the common stock then beneficially owned by all members of the Stockholder Group; provided, however, that any early termination also requires the written agreement of any member of the Stockholder Group that then has a right to appoint a director under the Stockholders Agreement.

Committees of the Board of Directors

Audit Committee

Rules implemented by NASDAQ the and the SEC require us to have an audit committee composed of at least three directors who meet the independence and experience standards established by the NASDAQ and the Exchange Act, subject to transitional relief during the one-year period following the completion of the IPO. We have established an audit committee that consists of C. Kent Potter, as chair, Brent S. Buckley and Eugene Voiland, each of whom the board has determined satisfy the applicable independence rules. SEC rules also require that a public company disclose whether or not its audit committee has an “audit committee financial expert” as a member. Messrs. Buckley and Voiland satisfy the definition of “audit committee financial expert.”

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants, our accounting practices, auditor rotation, service on multiple public company audit committees and hiring of employees from our auditor. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an audit committee charter defining the committee’s primary duties in a manner consistent with the rules of the SEC and NASDAQ listing standards.

Compensation Committee

Our compensation committee meets the requirements for independence under the current listing standards of the NASDAQ and current SEC rules and regulations. Our compensation committee currently consists of Eugene Voiland, as chair, Brent S. Buckley and Anne Mariucci, each of whom the board has determined satisfy the applicable independence rules. This committee establishes salaries, incentives and other forms of compensation for executive officers and recommends compensation for non-employee directors to our board. Our compensation committee also administers our executive incentive compensation and benefit plans and assesses compensation program risk. We have adopted a compensation committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC, the PCAOB and applicable NASDAQ or market standards.

Nominating and Corporate Governance Committee

Our nominating and corporate governance committee consists of Anne Mariucci, as chair, and C.Kent Potter, each of whom is "independent" under the applicable independence rules. This committee will identify, evaluate and recommend qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes, manage environmental, social and governance matters and maintain a management succession plan. We have adopted a nominating and corporate governance committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NASDAQ listing standards.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2017, our last completed fiscal year, our compensation committee consisted of Kaj Vazales, Brent S. Buckley and Eugene Voiland. During our last completed fiscal year, none of our executive officers served on the board of directors or compensation committee of a company that had an executive officer that served on our board or compensation committee, and no member of our board was an executive officer of a company in which one of our executive officers served as a member of the board of directors or compensation committee of that company.

Policy and Procedures Governing Related Party Transactions

We have adopted a written policy regarding transactions with related parties. See "Certain Relationships and Related Party Transactions—Procedures for Approval of Related Party Transactions."

Code of Business Conduct and Ethics

Our board of directors has adopted a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NASDAQ. Any waiver of this code may be made only by our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NASDAQ.

EXECUTIVE COMPENSATION

We are currently considered an "emerging growth company," within the meaning of the Securities Act, for purposes of the SEC's executive compensation disclosure rules. As such, we are subject to reduced compensation disclosure requirements. In accordance with such rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures regarding executive compensation for our last completed fiscal year. Further, our reporting obligations extend only to our "named executive officers," who are the individuals who served as our principal executive officer and our two other most highly compensated officers who served as executive officers during the last completed fiscal year (our "Named Executive Officers"). In accordance with the foregoing, our named executive officers are:

Name	Principal Position
A. T. "Trem" Smith	Chief Executive Officer
Cary D. Baetz	Chief Financial Officer
Gary A. Grove	Chief Operating Officer

2017 Summary Compensation Table

The following table summarizes the compensation earned by our Named Executive Officers for services rendered during the fiscal year ended December 31, 2017.

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(2)	All Other Compensation ($)(3)	Total ($)
A. T. "Trem" Smith *Chief Executive Officer*	2017	532,502 (4)	3,432,000	964,000	36,842	4,965,344
Cary D. Baetz *Chief Financial Officer*	2017	257,692	2,584,500	472,000	5,730	3,319,922
Gary A. Grove *Chief Operating Officer*	2017	314,053 (5)	2,326,050	433,000	14,227	3,087,330

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(1) Amounts reported in the "Stock Awards" column reflect the aggregate grant date fair value, computed in accordance with FASB ASC Topic 718, of the awards of RSUs and PRSUs made to each Named Executive Officer during fiscal year 2017, excluding the effect of estimated forfeitures. The grant date value of the RSUs was calculated by multiplying the number of RSUs granted by the value of a share of our common stock on the grant date, which was approximately $10.12. The grant date value of the PRSUs was calculated using a Monte Carlo Simulation Model, which resulted in a grant date value per PRSU of $7.04 for Mr. Smith and $7.11 for each of Messrs. Baetz and Grove. For additional information regarding the assumptions underlying this valuation please see Note 8 to our financial statements for the ten months ended December 31, 2017 and the two months ended February 28, 2017. See "—Narrative Disclosure to Summary Compensation Table—Long-Term Incentive Compensation" for additional information regarding these awards.

(2) Amounts represent awards under the Berry Petroleum Company, LLC Annual Incentive Plan for services provided in fiscal 2017. See "—Narrative Disclosure to Summary Compensation Table—Annual Incentive Plan" for additional information regarding these awards.

(3) Amounts reported in the "All Other Compensation" column include company matching contributions to the Named Executive Officers' 401(k) plan accounts, mobile phone reimbursements and the California tax reimbursements, which are described in "—Narrative Disclosure to Summary Compensation Table—Employment Agreements," as shown in the following table:

Named Executive Officer	Company 401(k) Plan Contributions ($)	Mobile Phone Reimbursements ($)	California Tax Reimbursements ($)	Total ($)
A. T. "Trem" Smith	16,200	749	19,893	36,842
Cary D. Baetz	—	—	5,730	5,730
Gary A. Grove	14,227	—	—	14,227

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(4) Base salary does not include fees of $120,000 paid to Mr. Smith by the Linn Entities for his service as a consultant to Berry LLC prior to the Effective Date.
(5) Base salary includes fees of $76,938 paid to Mr. Grove for services performed in his capacity as a consultant to Berry LLC prior to the date Mr. Grove was employed by the Company.

Narrative Disclosure to Summary Compensation Table

Employment Agreements

We entered into employment agreements with each of the Named Executive Officers in 2017, which have been amended and restated as described below in the section titled "—Actions Taken Following Fiscal Year End—Amended and Restated Employment Agreements." The employment agreements provide the Named Executive Officers with (a) an annualized base salary of $650,000 for Mr. Smith, $500,000 for Mr. Baetz and $450,000 for Mr. Grove, (b) an annual incentive opportunity (as described below in "—Annual Incentive Plan"), (c) a sign-on equity award with an aggregate grant date value of $4,000,000 for Mr. Smith, $3,000,000 for Mr. Baetz and $2,700,000 for Mr. Grove (as described below in "—Long-Term Incentive Compensation"), (d) under the Original Employment Agreements (as defined below), beginning in March 2020 and subject to their continued employment, our board of directors' evaluation of their performance and then-current market compensation levels, eligibility to receive annual equity awards with an aggregate grant date value of (i) one times base salary and target bonus amount for Mr. Smith and (ii) one times base salary, for each of Messrs. Baetz and Grove, (e) under the Amended Employment Agreements (as defined below), annual equity awards beginning at such time and in an amount determined by our board of directors (or a committee thereof) following evaluation of their performance and then-current market compensation levels and (f) for Messrs. Smith and Baetz, a tax gross-up payment to the extent any of their compensation is subject to California state income taxes.

The employment agreements contain certain restrictive covenants, including non-competition and non-solicitation covenants that are applicable during the executive's term of employment, and following a termination of employment. In the case of Mr. Smith, such restrictive covenants would be applicable for a period of two years following a termination of employment. In the case of Messrs. Baetz and Grove, the duration of these restrictive covenants following a termination of employment may be either two years (upon a termination by the Company without "Cause" or by the executive for "Good Reason," in each case, during the six-month (12-month, under the Amended Employment Agreements (as defined below)) period following a Sale of the Company (as defined in the employment agreement)) or 18 months (for all other terminations). The employment agreements also include restrictions on disclosure of confidential information. The employment agreements also provide for certain severance and change in control benefits as described below in the section titled "—Additional Narrative Disclosure—Potential Payments Upon Termination or Change in Control."

Long-Term Incentive Compensation

On June 15, 2017, we adopted the Berry Petroleum Corporation 2017 Omnibus Incentive Plan (the "2017 Plan"), which has been amended and restated as described below in the section titled "—Actions Taken Following Fiscal Year End—Omnibus Incentive Plan." The 2017 Plan provides for the grant of stock options, restricted stock awards, performance awards, other stock-based awards and other cash-based awards to employees, advisors and consultants of ours and our affiliates. In 2017, we granted sign-on equity awards consisting of 50% RSUs and 50% PRSUs to each of the Named Executive Officers in the amounts provided for in their employment agreements based on a grant date value of $10.00 per share of our common stock, which reflected our board of directors' good faith estimate of the value of our common stock at the time the awards were granted based on the value of shares received by certain holders of Unsecured Notes in the reorganization transactions upon our emergence from bankruptcy. The RSUs and PRSUs granted to the Named Executive Officers are described below in "—Outstanding Equity Awards at 2017 Fiscal Year-End." For information regarding the treatment of the awards upon a change in control or termination of employment, see "—Additional Narrative Disclosure—Potential Payments Upon Termination or Change in Control."

Annual Incentive Plan

Each of the Named Executive Officers is eligible to receive an annual award under the Berry Petroleum Company, LLC Annual Incentive Plan (the "AIP") of up to 100% of base salary at target level and 200% of base salary at maximum level. For 2017, the Named Executive Officers' annual award target was prorated based on the effective date of the applicable employment agreement.

Under the annual incentive plan ("AIP") as applied to the Named Executive Officers for 2017, performance was measured based 70% on Company performance and 30% on discretionary factors. The weighting of these components for the AIP awards may change in future years in the Compensation Committee's discretion and did change for 2018. Company performance is based on various metrics including production, total operating expenditure (consisting of lease operating, electricity, transportation and marketing expenses and taxes, other than income taxes, but excluding incentive compensation costs) per barrel of oil equivalent, cash general and administrative expense (excluding restructuring and incentive compensation costs) and adjusted EBITDA (excluding restructuring and incentive compensation costs). The discretionary AIP component is measured based on the factors the Compensation Committee deems appropriate. The Named Executive Officers must generally be employed on the date the AIP payments are actually paid in order to receive payment.

The AIP payments for 2017 were paid in 2018 following a year-end review of the applicable performance criteria. The actual bonus amounts paid to each Named Executive Officer with respect to fiscal year 2017 are as follows:

Name	AIP Award Payout ($)
Mr. Smith	964,000
Mr. Baetz	472,000
Mr. Grove	433,000

Other Compensation Elements

We offer participation in a broad-based retirement plan intended to provide benefits under section 401(k) of the Code pursuant to which our employees, including our Named Executive Officers, are permitted to contribute a portion of their eligible compensation to a tax-qualified retirement account. We also provide discretionary matching contributions under the 401(k) plan currently equal to 100% of the first 6% of eligible compensation contributed to the 401(k) plan. All matching contributions are immediately vested.

Outstanding Equity Awards at 2017 Fiscal Year-End

The following table reflects information regarding outstanding equity-based awards held by our Named Executive Officers as of December 31, 2017.

		Stock Awards	
Name	Grant Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)
A. T. "Trem" Smith	06/22/2017	200,000 (1)	2,502,000 (2)
	06/22/2017	200,000 (3)	1,920,000 (4)
Cary D. Baetz	06/29/2017	150,000 (1)	1,876,500 (2)
	06/29/2017	150,000 (3)	1,440,000 (4)
Gary A. Grove	06/29/2017	135,000 (1)	1,688,850 (2)
	06/29/2017	135,000 (3)	1,296,000 (4)

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(1) Represents RSUs granted to our Named Executive Officers that were outstanding as of December 31, 2017. The RSUs vest one-third per year on the anniversary of the vesting commencement date. These dates were March 1, 2017 for Mr. Smith, June 20, 2017 for Mr. Baetz and June 15, 2017 for Mr. Grove. See "—Long-Term Incentive Compensation" for additional information regarding these awards.
(2) These amounts represent the aggregate market value of outstanding RSUs held by each Named Executive Officer on December 31, 2017 and are calculated by multiplying the number of RSUs outstanding on December 31, 2017 by the value of a share of our common stock on such date, which was approximately $12.51.

(3) Represents PRSUs granted to our Named Executive Officers that were outstanding as of December 31, 2017. The PRSUs have a performance period from the grant date of the awards to the third anniversary of such date. One-third of the PRSUs will vest if the volume weighted average price of our common stock equals or exceeds, for 30 consecutive trading days during the applicable performance period each of $13.00, $15.00 and $17.00, respectively. The PRSUs vested at the $13.00 and $15.00 level on October 2, 2018 and October 5, 2018, respectively. The PRSUs are settled within 30 days of the applicable performance condition being satisfied. See "—Long-Term Incentive Compensation" for additional information regarding these awards.

(4) These amounts represent the aggregate market value of outstanding PRSUs held by each Named Executive Officer on December 31, 2017 and are calculated using a Monte Carlo Simulation Model, which resulted in a value per PRSU as of such date of $9.60.

Additional Narrative Disclosure

Potential Payments Upon Termination or Change in Control

Termination of Employment

The employment agreements with each of Messrs. Smith, Baetz and Grove were amended and restated effective August 22, 2018 (the "Amended Employment Agreements"). Under the employment agreements as in effect on December 31, 2017, prior to the amendment and restatement (the "Original Employment Agreements"), if the applicable Named Executive Officer's employment had been terminated without "Cause" (and not due to death or disability), or by the Named Executive Officer for "Good Reason" (and, for Mr. Smith, if we elect not to renew his employment agreement), then each of the Named Executive Officers would have been eligible to receive salary continuation payments payable in 12 substantially equal monthly installments. The salary continuation payments for Mr. Smith would have been equal to the sum of one times base salary and the target AIP payment for the year in which termination occurs. The salary continuation payments for Messrs. Baetz and Grove would have been equal to the sum of one times base salary for the year in which termination occurs and the of greater of: (a) the AIP payment received by the applicable Named Executive Officer for the immediately preceding calendar year or (b) the target AIP payment for the year in which such termination occurs.

Under the Amended Employment Agreements, each Named Executive Officer is, and under the Original Employment Agreements prior to amendment, Messrs. Baetz and Grove were, also eligible to receive a lump-sum payment of any earned but unpaid AIP payment for the calendar year ending prior to the termination date and a prorated AIP payment for the year in which the termination occurs.

Under the Original Employment Agreements, each of the Named Executive Officers was eligible for up to 18 months (or, in the case of Mr. Smith, 12 months) of COBRA continuation coverage under our group health plans. Each of Messrs. Baetz and Grove is eligible to receive certain additional benefits in the event his employment terminates within the six-month period following a sale of the Company as described below in "—Change in Control."

Under Mr. Smith's Original Employment Agreement and under the award agreements pursuant to which the Named Executive Officers' outstanding equity awards were granted, each of the Named Executive Officers is eligible for 12 months' accelerated vesting of any unvested equity awards subject to time-based vesting held by him as of his termination date upon a termination without "Cause" or for "Good Reason." In connection with such termination, each Named Executive Officers' PRSUs will remain outstanding and be eligible to vest based on actual performance until the earlier of (i) the date that is 12 months following the termination date and (ii) the last day of the applicable performance period. Upon a "Change in Control," 100% of the RSUs and the PRSUs will vest as described below in "—Change in Control."

Under both the Amended Employment Agreements and the Original Employment Agreements, the severance benefits are subject to the Named Executive Officer's execution, delivery and non-revocation of a release of claims in favor of us and continued compliance with applicable restrictive covenants.

Under the Original Employment Agreements, "Cause" generally means, with respect to a Named Executive Officer, any of the following: (i) the repeated failure to fulfill his obligations under his employment agreement; (ii) a material breach of our written code of conduct or any of our other material written policies or regulations (and in the case of (i) and (ii), if able to be cured, remaining uncured for 30 days following written notice from us); (iii) a conviction of, or plea of guilty or no contest to, a felony or to a crime involving moral turpitude resulting in financial or reputational harm to us or our affiliates; (iv) engagement in conduct that constitutes gross negligence or gross misconduct in carrying out his job duties; (v) a material violation of any restrictive covenant to which he is subject; or (vi) any act involving dishonesty relating to, and adversely affecting, our business.

Under the Original Employment Agreements, "Good Reason" generally means the occurrence of any of the following without the Named Executive Officer's written consent: (i) a material reduction in base salary; (ii) any material breach by us of any material provision of the employment agreement; (iii) a material diminution in the nature or scope of the Named Executive Officer's authority or responsibilities; (iv) a permanent relocation of his principal place of employment by more than 30 miles; or (v) our failure to obtain an agreement from any successor to assume the employment agreement. The conditions described above are subject in each case to customary notice and cure provisions.

Pursuant to the award agreements with each of the Named Executive Officers, upon a termination of employment due to death or "Disability" (as defined in the 2017 Plan), each Named Executive Officer's RSU award and PRSU award will be deemed fully vested and will be settled within 30 days of such termination.

Upon a termination of employment for "Cause" or without "Good Reason," the Named Executive Officer will forfeit all outstanding RSUs and PRSUs.

Termination of Employment under the Amended Employment Agreements

Under the Amended Employment Agreements, if the applicable Named Executive Officer's employment is terminated without "Cause" (and not due to death or disability), or by the Named Executive Officer for "Good Reason" (and, for Mr. Smith, if we elect not to renew the term of his Amended Employment Agreement), in each case, other than during the 12-month period following a Change in Control (as defined below), then the Named Executive Officer is eligible to receive salary continuation payments payable in 12 (for Mr. Smith, 18) substantially equal monthly installments. The salary continuation payments are equal to one times (for Mr. Smith, 1.5 times) the sum of the Named Executive Officer's base salary and the target AIP payment for the year in which the termination of the Named Executive Officer's employment occurs. The Named Executive Officers are also eligible to receive a lump-sum payment of any earned but unpaid AIP payment for the calendar year ending prior to the termination date and a prorated AIP payment for the year in which the termination occurs.

Each of the Named Executive Officers is eligible for up to 12 months (or, in the case of Mr. Smith, 18 months) of COBRA continuation coverage under our group health plans. Each Named Executive Officer is also eligible to receive certain additional benefits in the event his employment terminates within the 12-month period following a sale of the Company, as described below in "—Change in Control under the Amended Employment Agreements."

Under the Amended Employment Agreements, "Cause" generally means, with respect to a Named Executive Officer, any of the following: (i) the repeated failure to fulfill his obligations with respect to his employment; (ii) a conviction of, or plea of guilty or no contest to, a felony or to a crime involving moral turpitude resulting in financial or reputational harm to us or any of our affiliates; (iii) engagement in conduct that constitutes gross negligence or gross misconduct in carrying out his job duties; (iv) a material violation of any restrictive covenant to which he is subject; (v) any act involving dishonesty relating to, and adversely affecting, our business; or (vi) a material breach of our written code of ethics or any of our other material written policies or regulations (and in the case of (i) and (vi), if able to be cured, remaining uncured for 30 days following written notice from us).

Under the Amended Employment Agreements, "Good Reason" generally means the occurrence of any of the following without the Named Executive Officer's consent: (i) a material reduction in base salary, other than reductions of less than 10% as part of reductions to base salaries of all similarly situated executives; (ii) a permanent relocation of his principal place of employment by more than 30 miles; (iii) any material breach by us of any material provision of the Amended Employment Agreement; (iv) our failure to obtain an agreement from any successor to assume the Amended Employment Agreement; or (v) a material diminution in the nature or scope of the Named Executive Officer's authority or responsibilities. Each of the conditions described above is subject to customary notice and cure provisions.

Change in Control

Under the Original Employment Agreements, if either of Messrs. Baetz's or Grove's employment was terminated without "Cause" or by him for "Good Reason" within the six-month period following a Sale of the Company (as defined in the employment agreement), his salary continuation payments would have been increased to the sum of two times base salary for the year in which termination occurs and the of greater of: (a) the AIP payment received by the applicable Named Executive Officer for the immediately preceding calendar year or (b) the target AIP payment for the year in which such termination occurs.

Pursuant to the award agreements with each of the Named Executive Officers, all outstanding and unvested RSUs and PRSUs held by each of the Named Executive Officers will vest 100% upon a Change in Control and be settled within 30 days following such Change in Control.

For purposes of the 2017 Plan, "Change in Control" generally means: (i) any "person" (other than the Company and certain related parties), becoming the beneficial owner, directly or indirectly, of securities representing more than 50% of the combined voting power of the Company; (ii) during any period of 24 consecutive calendar months, our directors as of the first day of such period (the "Incumbent Directors") cease for any reason to constitute a majority of our board of directors, provided that a director elected or nominated by our stockholders (other than as a result of an actual or threatened proxy contest) whose appointment was approved by two-thirds of the Incumbent Directors shall be considered an Incumbent Director for this purpose; (iii) any consolidation or merger in which our stockholders immediately prior to such consolidation or merger do not beneficially own securities representing more than 50% of the total voting power of the surviving or continuing entity; or (iv) (a) a complete liquidation or dissolution of us or (b) a sale or disposition of all or substantially all of our assets in one or a series of related transactions.

Change of Control under the Amended Employment Agreements

Under the Amended Employment Agreements, if a Named Executive Officer's employment is terminated without "Cause" or by him for "Good Reason" within the 12-month period following a Sale of the Company (as defined in the Amended Employment Agreement), (i) his salary continuation payments will be increased to two times (2.5 times for Mr. Smith) the sum of his base salary for the year in which such termination occurs and the target AIP payment for the year in which such termination occurs and (ii) his COBRA continuation coverage is increased to 18 months.

Actions Taken Following Fiscal Year End

Omnibus Incentive Plan

In order to incentivize individuals providing services to us or our affiliates, our board of directors adopted the 2017 Plan, which was amended and restated as of March 7, 2018 (the "Prior Plan"). In connection with the IPO, our board of directors adopted the Restated Incentive Plan effective as of June 27, 2018. The Restated Incentive Plan provides for the grant, from time to time, at the discretion of our board of directors or a committee thereof, of stock options, stock appreciation rights ("SARs"), restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards, and substitute awards.

Subject to adjustment in the event of certain transactions or changes of capitalization in accordance with the Restated Incentive Plan, the maximum number of shares of our common stock that may be issued pursuant to awards under the Restated Incentive Plan is 10,000,000, inclusive of the number of shares of common stock previously issued pursuant to an award (or made subject to an award that has not expired or been terminated) under the Prior Plan or the 2017 Plan.

Amended and Restated Employment Agreements

The Amended Employment Agreements were entered into with each of our Named Executive Officers on August 22, 2018. The Amended Employment Agreements (i) modify the termination of employment and change in control benefits provided to the Named Executive Officers, as described above under "—Additional Narrative Disclosure—

Potential Payments Upon Termination or Change in Control," (ii) for Messrs. Baetz and Grove, provide that the two year, rather than 18 month, duration of the restrictive covenants now applies following a termination of employment without "Cause" or by the executive for "Good Reason," in each case, during the twelve-month, rather than six-month, period following a Sale of the Company (as defined in the Amended Employment Agreements), (iii) provide that Mr. Smith is eligible to receive a lump-sum payment of any earned but unpaid AIP payment for the calendar year ending prior to the termination date and a prorated AIP payment for the year in which the termination occurs and (iv) made certain immaterial changes to harmonize the terms among the Named Executive Officers' employment agreements. All other material terms contained in the employment agreements remain substantially unchanged in the Amended Employment Agreements.

Director Compensation

The table below summarizes the compensation paid to our non-employee director for the fiscal year ended December 31, 2017.

Name[(1)]	Fees Earned or Paid in Cash ($)[(2)]	Stock Awards ($)[(3)]	Total ($)
Eugene "Gene" Voiland	29,167	151,800	180,967

(1) While Messrs. Smith and Baetz, Brent S. Buckley and Kaj Vazales also served on our board of directors during 2017, they did not receive any additional compensation for their service as directors. The compensation received by each of Messrs. Smith and Baetz as an officer of the Company is shown in "—2017 Summary Compensation Table."

(2) Mr. Voiland joined our board of directors on June 15, 2017. The amount in this column reflects amounts received for his services as a director from June 15, 2017 to December 31, 2017.

(3) Reflects the aggregate grant date fair value of 15,000 RSUs granted to Mr. Voiland during 2017 computed in accordance with FASB ASC Topic 718, determined without regard to estimated forfeitures. The RSUs vested May 23, 2018.

On August 21, 2018, we adopted a non-employee director compensation program, pursuant to which each non-employee director receives (i) an annual grant of restricted stock units with a value at grant of $150,000, (ii) an annual cash fee of $75,000 for membership on our board of directors, (iii) an annual cash fee of $30,000 for committee chairman positions and (iv) an annual cash fee of $15,000 for committee membership positions. All annual cash fees are payable quarterly in arrears.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

As of November 29, 2018, we had approximately 240 holders of record of our common stock. This number excludes owners for whom shares of common stock may be held in "street" name.

Except where another date is indicated, the following table sets forth the beneficial ownership of our common stock and shows the number of shares of common stock and the respective percentages, as of November 29, 2018, owned by:

- each person known to us to beneficially own more than 5% of our outstanding common stock;
- each member of our board of directors;
- each of our named executive officers; and
- all of our directors and executive officers as a group.

Except as otherwise noted, the person or entities listed below have sole voting and investment power with respect to all shares of our common stock beneficially owned by them, except to the extent this power may be shared with a spouse. All information with respect to beneficial ownership has been compiled from public filings or furnished by the respective 5% or more stockholders, directors or executive officers, as the case may be. Unless otherwise noted, the mailing address of each listed more than 5% stockholder, director or executive officer is c/o Berry Petroleum Corporation, 16000 N. Dallas Parkway, Suite 500, Dallas, Texas 75248. The percentages of ownership are based on 81,651,098 shares of common stock outstanding as of November 29, 2018.

	Shares of Common Stock Beneficially Owned[1]	
	Number	**%**
Directors and named executive officers:		
A. T. (Trem) Smith *(President, Chief Executive Officer and Director)*	147,532	*
Cary Baetz *(Executive Vice President, Chief Financial Officer and Director)*	141,250	*
Gary A. Grove *(Executive Vice President and Chief Operating Officer)*	89,924	*
Brent S. Buckley *(Director)*	—	—%
Eugene J. Voiland *(Director)*	15,000	*
C. Kent Potter *(Director)*	—	—%
Anne L. Mariucci *(Director)*	—	—%
All directors and executive officers as a group (7 persons)	393,706	*
5% stockholders:		
AllianceBernstein Funds[2]	4,673,004	5.7%
Benefit Street Partners[3]	18,588,691	22.8%
CarVal Investors[4]	6,555,642	8.0%
FMR LLC[5]	8,219,818	10.1%
Goldman Sachs Asset Management[6]	6,895,771	8.4%
Oaktree Capital Management[7]	7,794,350	9.5%
Western Asset Management Company, LLC[8]	6,750,202	8.3%

* less than 1%

(1) The amounts and percentages of common stock beneficially owned are reported based on SEC regulations. Under SEC rules, a person is deemed to be a "beneficial owner" of a security if that person has or shares voting power, which includes the power to vote or direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Under these rules, more than

one person may be deemed to be a beneficial owner of the same securities, and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest. The number of shares beneficially owned by a person includes any derivative securities to acquire common stock held by that person that are currently exercisable or convertible within 60 days after the date of this prospectus. The shares issuable under any such securities are treated as outstanding for computing the percentage ownership of the person holding these securities, but are not treated as outstanding for the purposes of computing the percentage ownership of any other person.

(2) Consists of (i) 133,343 shares of common stock owned by AB Bond Fund Inc. – AB Income Fund, (ii) 5,951 shares of common stock owned by AB Bond Fund, Inc. - AB Credit Long/Short Portfolio, (iii) 3,917 shares of common stock owned by AB Bond Fund, Inc. - AB FlexFee High Yield Portfolio, (iv) 46,608 shares of common stock owned by AB Collective Investment Trust Series - AB US High Yield Collective Trust, (v) 2,987,112 shares of common stock owned by AB FCP I - Global High Yield Portfolio, (vi) 1,158,054 shares of common stock owned by AB High Income Fund, Inc., (vii) 12,792 shares of common stock owned by AB SICAV I - US High Yield Portfolio., (viii) 27,383 shares of common stock owned by AllianceBernstein Global High Fund Mother Fund, (ix) 2,871 shares of common stock owned by AllianceBernstein Global High Income Open B, (x) 73,465 shares of common stock owned by Teachers' Retirement System of Louisiana, (xi) 9,528 shares of common stock owned by The AB Portfolios - AB All Market Total Return Portfolio, (xii) 167,780 shares of common stock owned by AllianceBernstein Global High Income Fund, Inc., (xiii) 37,000 shares of common stock owned by AB Arya Partners (Master) Fund SICAV-RAIF S.C.Sp. and (xiv) 7,200 shares of common stock owned by EQ/AllianceBernstein Small Cap Growth (collectively, the "AllianceBernstein funds"). AllianceBernstein L.P. is investment advisor to the AllianceBernstein funds. Neil Ruffell, in his position as VP Corporate Actions of AllianceBernstein L.P., may be deemed to have voting and investment power with respect to the common stock owned by the AllianceBernstein funds. The address for the foregoing persons is 1345 Avenue of the Americas, New York, NY 10105.

(3) Consists of (i) 4,788,500 shares of common stock owned by Benefit Street Credit Alpha Master Fund Ltd., (ii) 3,128,350 shares of common stock owned by Providence Debt Fund III L.P., (iii) 2,862,114 shares of common stock owned by Landmark Wall SMA L.P., (iv) 2,819,927 shares of common stock owned by BSP Special Situations Master A L.P., (v) 1,935,020 shares of common stock owned by Energy Debt Strategy Subsidiary, Ltd., (vi) 1,665,963 shares of common stock owned by Providence Debt Fund III Master (Non-US) L.P., (vii) 435,233 shares of common stock owned by SEI Institutional Investments Trust – High Yield Bond Fund, (viii) 323,764 shares of common stock owned by SEI Institutional Managed Trust – High Yield Bond Fund, (ix) 315,000 shares of common stock owned by Hampshire Credit Alpha Master Fund LP, (x)164,334 shares of common stock owned by SEI Global Master Fund plc – The SEI High Yield Fixed Income Fund, (xi) 75,648 shares of common stock owned by U.S. High Yield Bond Fund and (xii) 74,838 shares of common stock owned by Blackrock Strategic Funds (UCITS) (all such owners of such securities, collectively, the "BSP Funds"). Benefit Street Partners L.L.C. serves as the investment adviser to each of the BSP Funds. The sole managing member of Benefit Street Partners L.L.C. is BSP Holdco, LLC. The sole member and Chief Executive Officer of BSP Holdco LLC is Thomas J. Gahan. As a result, Mr. Gahan may be deemed to have voting and investment power with respect to all of the shares of the common stock owned by the BSP Funds. The address for each of the BSP Funds and Mr. Gahan is 9 West 57th Street, Suite 4920, New York, New York 10019. Pursuant to the Stockholders Agreement, Benefit Street Partners has the right to designate a director for nomination to our board of directors. Mr. Buckley currently serves as Benefit Street Partners' designee. For more information, please read "Certain Relationships and Related Party Transactions."

(4) Consists of (i) 487,864 shares of common stock held by CarVal GCF Lux Securities S.à r.l., (ii) 803,348 shares of common stock held by CVI AA Lux Securities S.à r.l., (iii) 158,226 shares of common stock held by CVI AV Lux Securities S.à r.l., (iv) 1,191,224 shares of common stock held by CVIC Lux Securities Trading S.à r.l., (v) 3,193,056 shares of common stock held by CVI CVF III Lux Securities S.à r.l. and (vi) 721,924 shares of common stock held by CVI CVF IV Lux Securities S.à r.l. (collectively, the "CarVal funds"). Cécile Gadisseur and Paul Vermaak, in their position as managers of the CarVal funds, may be deemed to share voting and investment power over the shares held by each of the CarVal funds. CarVal Investors, LLC (the "Investment Manager") serves as the investment manager to each of the CarVal funds. The Investment Manager and each of the directors of CarVal funds disclaim beneficial ownership of the common shares held by the CarVal funds. The address for the foregoing persons is 11-13 Boulevard de la Foire, Luxembourg, L-1528.

(5) Based solely on a Schedule 13G filed on December 10, 2018 by FMR LLC and Abigail P. Johnson. 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. 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. FMR LLC has sole voting power over 625,957 shares and sole dispositive power over 8,219,818 shares. Abigail P. Johnson has sole dispositive power over 8,219,818 shares. The address for FMR LLC is 245 Summer Street, Boston, MA 02210.

(6) Consists of (i) 2,291,920 shares of common stock owned by Goldman Sachs Trust—Goldman Sachs High Yield Fund, (ii) 1,357,133 shares of common stock owned by Goldman Sachs Trust—Goldman Sachs Tactical Tilt Overlay Fund, (iii) 1,033,035 shares of common stock owned by Energy Investment Opportunities Offshore WTI Ltd, (iv) 1,296,719 shares of common stock owned by Energy Investment Opportunities LLC, (v) 584,792 shares of common stock owned by Global High Yield Portfolio II WTI Ltd, (vi) 62,021 shares of common stock owned by EIOF PIV WTI Ltd, (vii) 121,127 shares of common stock owned by Factory Mutual Insurance Company, (viii) 146,596 shares of common stock owned by Tactical Tilt Overlay LLC and (ix) 2,428 shares of common stock owned by Insurance Company of the West, (collectively, the "GSAM funds and accounts"). Goldman Sachs Asset Management L.P. serves as the investment manager to each of the GSAM funds and accounts. The Fixed Income Portfolio Management Team of Goldman Sachs Asset Management, L.P., may be deemed to have voting and investment power with respect to the common stock held by the GSAM funds and accounts. The address for the foregoing persons is 200 West Street, 3rd Floor, New York, NY 10282.

(7) Consists of (i) 5,531,482 shares of common stock held by Oaktree Opportunities Fund X Holdings (Delaware), L.P. ("Fund X Delaware") and (ii) 2,262,868 shares of common stock held by Oaktree Value Opportunities Fund Holdings, L.P. ("VOF Holdings"). Oaktree Fund GP, LLC ("Fund GP") is the general partner of Fund X Delaware; Oaktree Value Opportunities Fund GP, L.P. ("VOF GP") is the general partner of VOF Holdings; Oaktree Value Opportunities Fund GP Ltd. ("VOF GP Ltd.") is the general partner of VOF GP; Oaktree Fund GP I, L.P. ("GP I") is

the managing member of Fund GP and the sole shareholder of VOF GP Ltd.; Oaktree Capital I, L.P. (“Capital I”) is the general partner of GP I; OCM Holdings I, LLC (“Holdings I”) is the general partner of Capital I; Oaktree Holdings, LLC (“Holdings”) is the managing member of Holdings I; Oaktree Capital Management, L.P. (“Management”) is the sole director of VOF GP Ltd.; Oaktree Holdings, Inc. (“Holdings, Inc.”) is the general partner of Management; Oaktree Capital Group, LLC (“OCG”) is the managing member of Holdings and the sole shareholder of Holdings, Inc.; and Oaktree Capital Group Holdings GP, LLC (“OCGH GP”) is the duly elected manager of OCG. The members of OCGH GP are Howard S. Marks, Bruce A. Karsh, Jay S. Wintrob, John B. Frank and Sheldon M. Stone. The address for the foregoing persons is 333 South Grand Avenue, 28th Floor, Los Angeles, CA 90071. Pursuant to the Stockholders Agreement, Oaktree Capital Management previously had the right to designate a director for nomination to our board of directors. For more information, please read “Certain Relationships and Related Party Transactions.”

(8) Consists of (i) 492,494 shares of common stock held by Western Asset Opportunistic US$ High Yield Securities Portfolio, L.L.C., (ii) 177,069 shares of common stock held by Stichting Pensioenfonds DSM Nederland, (iii) 243,795 shares of common stock held by Western Asset Funds, Inc. - Western Asset High Yield Fund, (iv) 36,143 shares of common stock held by Consulting Group Capital Markets Funds - High Yield Investments, (v) 193,156 shares of common stock held by Legg Mason Western Asset US High Yield Fund, (vi) 47,853 shares of common stock held by Employees' Retirement System of the State of Hawaii, (vii) 198,479 shares of common stock held by Kern County Employees' Retirement Association, (viii) 391,651 shares of common stock held by Western Asset High Income Opportunity Fund Inc., (ix) 416,915 shares of common stock held by John Hancock Funds II High Yield Fund, (x) 195,481 shares of common stock held by John Hancock Variable Insurance Trust High Yield Trust, (xi) 166,055 shares of common stock held by Brighthouse Funds Trust II - Western Asset Management Strategic Bond Opportunities Portfolio, (xii) 135,551 shares of common stock held by Legg Mason Partners Income Trust - Western Asset Global High Yield Bond Fund, (xiii) 126,186 shares of common stock held by Legg Mason Western Asset Global High Yield Bond Fund, (xiv) 305,744 shares of common stock held by Western Asset Global High Income Fund Inc., (xv) 370,182 shares of common stock held by Western Asset High Income Fund II Inc., (xvi) 65,226 shares of common stock held by Legg Mason Partners Variable Income Trust - Western Asset Variable Global High Yield Bond Portfolio, (xvii) 542,523 shares of common stock held by Western Asset Short Duration High Income Fund, (xviii) 43,936 shares of common stock held by Legg Mason Partners Income Trust - Western Asset Income Fund, (xix) 145,954 shares of common stock held by Southern California Edison Company Retirement Plan Trust, (xx) 172,752 shares of common stock held by Western Asset Strategic US$ High Yield Portfolio, L.L.C., (xxi) 74,788 shares of common stock held by International Union, UAW Strike Trust, (xxii) 116,613 shares of common stock held by WA High Income Corporate Bond (Multi-Currency) Fund, (xxiii) 233,094 shares of common stock held by Western Asset High Yield Defined Opportunity Fund Inc., (xxiv) 8,479 shares of common stock held by Western Asset Multi-Asset Credit Portfolio Master Fund, Ltd., (xxv) 187,640 shares of common stock held by Western Asset Short-Dated High Yield Master Fund, Ltd., (xxvi) 59,778 shares of common stock held by International Union, UAW Master Pension Trust, (xxvii) 360,858 shares of common stock held by Western Asset Middle Market Debt Fund, Inc., (xxviii) 46,846 shares of common stock held by Ascension Alpha Fund, LLC, (xxix) 8,617 shares of common stock held by Anthem Health Plans, Inc., (xxx) 39,106 shares of common stock held by Western Asset Funds, Inc. - Western Asset Macro Opportunities Fund, (xxxi) 34,986 shares of common stock held by Ascension Healthcare Master Pension Trust, (xxxii) 13,656 shares of common stock held by Kaiser Foundation Hospitals, (xxxiii) 9,238 shares of common stock held by Kaiser Permanente Group Trust, (xxxiv) 3,213 shares of common stock held by The Walt Disney Company Retirement Plan Master Trust, (xxxv) 123,213 shares of common stock held by VantageTrust III Master Collective Investment Funds Trust, (xxxvi) 730,306 shares of common stock held by Western Asset Middle Market Income Fund Inc., (xxxvii) 8,033 shares of common stock held by Hand Composite Employee Benefit Trust - Western Asset Income CIF, (xxxviii) 3,555 shares of common stock held by JNL Multi-Manager Alternative Fund, (xxxix) 11,312 shares of common stock held by Western Asset Premier Bond Fund, (xl) 6,267 shares of common stock held by John Lewis Partnership Pensions Trust, (xli) 42,640 shares of common stock held by Legg Mason Western Asset Global Multi Strategy Fund, (xlii) 12,183 shares of common stock held by Diageo Pension Trust Limited, (xliii) 391 shares of common stock held by Legg Mason Western Asset Short Duration High Income Bond Fund, (xliv) 2,350 shares of common stock held by GuideStone Funds Global Bond Fund, (xlv) 33,068 shares of common stock held by Legg Mason IF Western Asset Global Multi Strategy Bond Fund, (xlvi) 838 shares of common stock held by Western Asset High Yield Credit Energy Portfolio, LLC and (xlvii) 111,989 shares of common stock held by Stichting Pensioenfonds Sabic (collectively, the “WAMC funds”). Western Asset Management Company, LLC is the investment manager of the WAMC funds and may be deemed to have voting and investment power with respect to the shares of common stock owned by the WAMC funds. The address for the foregoing persons is 385 E. Colorado Blvd. Pasadena, CA 91101.

SELLING STOCKHOLDERS

This prospectus covers the offer and sale of up to an aggregate of 61,420,234 shares of common stock that may be offered and sold from time to time by the selling stockholders identified below under this prospectus, subject to any appropriate adjustment as a result of any subdivision, split, combination or other reclassification of our common stock.

We have prepared the table, the paragraph immediately following this paragraph, and the related notes based on information supplied to us by the selling stockholders on or prior to December 4, 2018. We have not sought to verify such information. The percentages of ownership are based on 81,651,098 shares of common stock outstanding as of November 29, 2018.

	Shares of Common Stock Beneficially Owned Prior to the Offering[(1)]		Number of Shares of Common Stock Being Offered Hereby	Shares of Common Stock Beneficially Owned After this Offering[(2)]	
	Number	%		Number	%
AllianceBernstein Funds[(3)]	4,673,004	5.7%	4,628,804	44,200	*
Benefit Street Partners[(4)]	18,588,691	22.8%	18,588,691	—	—%
CarVal Investors[(5)]	6,555,642	8.0%	6,458,733	96,909	*
CI Investments[(6)]	3,823,643	4.7%	3,823,643	—	—%
Goldman Sachs Asset Management[(7)]	6,895,771	8.4%	6,895,771	—	—%
Jackson Valley Fund LP[(8)]	155,313	*	155,313	—	—%
Marathon Asset Management[(9)]	1,958,374	2.4%	1,958,374	—	—%
Merrill Lynch, Pierce, Fenner & Smith, Incorporated[(10)]	384,843	*	384,843	—	—%
Oaktree Capital Management[(11)]	7,794,350	9.5%	7,794,350	—	—%
South Dakota Retirement System[(12)]	887,669	1.1%	887,669	—	—%
Venor Capital[(13)]	3,093,841	3.8%	3,093,841	—	—%
Western Asset Management Company, LLC[(14)]	6,750,202	8.3%	6,750,202	—	—%

* less than 1%

(1) The amounts and percentages of common stock beneficially owned are reported based on SEC regulations. Under SEC rules, a person is deemed to be a "beneficial owner" of a security if that person has or shares voting power, which includes the power to vote or direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Under these rules, more than one person may be deemed to be a beneficial owner of the same securities, and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest. The number of shares beneficially owned by a person includes any derivative securities to acquire common stock held by that person that are currently exercisable or convertible within 60 days after the date of this prospectus. The shares issuable under any such securities are treated as outstanding for computing the percentage ownership of the person holding these securities, but are not treated as outstanding for the purposes of computing the percentage ownership of any other person.

(2) Represents the amounts of shares that will be held by the selling stockholder after completion of this offering based on the assumptions that: (a) all shares registered for sale by the registration statement of which this prospectus is a part will be sold by or on behalf of the selling stockholder; and (b) no other shares of our common stock will be acquired prior to completion of this offering by the selling stockholder. The selling stockholders may sell all, some or none of the shares offered pursuant to this prospectus and may sell other shares of our common stock that they may own pursuant to another registration statement under the Securities Act or sell some or all of their shares pursuant to an exemption from the registration requirements of the Securities Act, including under Rule 144 promulgated thereunder or any successor rule. To our knowledge, there are currently no agreements, arrangements or understandings with respect to the sale of any of the shares that may be held by the selling stockholders after completion of this offering or otherwise.

(3) Consists of (i) 133,343 shares of common stock owned by AB Bond Fund Inc. – AB Income Fund, (ii) 5,951 shares of common stock owned by AB Bond Fund, Inc. - AB Credit Long/Short Portfolio, (iii) 3,917 shares of common stock owned by AB Bond Fund, Inc. - AB FlexFee High Yield Portfolio, (iv) 46,608 shares of common stock owned by AB Collective Investment Trust Series - AB US High Yield Collective Trust, (v) 2,987,112 shares of common stock owned by AB FCP I - Global High Yield Portfolio, (vi) 1,158,054 shares of common stock owned by AB High Income Fund, Inc., (vii) 12,792 shares of common stock owned by AB SICAV I - US High Yield Portfolio., (viii) 27,383 shares of common stock owned by AllianceBernstein Global High Fund Mother Fund, (ix) 2,871 shares of common stock owned by AllianceBernstein Global High Income Open B, (x) 73,465 shares of common stock owned by Teachers' Retirement System of Louisiana, (xi) 9,528 shares of common stock owned by The AB Portfolios - AB All Market Total Return Portfolio, (xii) 167,780 shares of common stock owned by

AllianceBernstein Global High Income Fund, Inc., (xiii) 37,000 shares of common stock owned by AB Arya Partners (Master) Fund SICAV-RAIF S.C.Sp. and (xiv) 7,200 shares of common stock owned by EQ/AllianceBernstein Small Cap Growth (collectively, the “AllianceBernstein funds”). AllianceBernstein L.P. is investment advisor to the AllianceBernstein funds. Neil Ruffell, in his position as VP Corporate Actions of AllianceBernstein L.P., may be deemed to have voting and investment power with respect to the common stock owned by the AllianceBernstein funds. The address for the foregoing persons is 1345 Avenue of the Americas, New York, NY 10105.

(4) Consists of (i) 4,788,500 shares of common stock owned by Benefit Street Credit Alpha Master Fund Ltd., (ii) 3,128,350 shares of common stock owned by Providence Debt Fund III L.P., (iii) 2,862,114 shares of common stock owned by Landmark Wall SMA L.P., (iv) 2,819,927 shares of common stock owned by BSP Special Situations Master A L.P., (v) 1,935,020 shares of common stock owned by Energy Debt Strategy Subsidiary, Ltd., (vi) 1,665,963 shares of common stock owned by Providence Debt Fund III Master (Non-US) L.P., (vii) 435,233 shares of common stock owned by SEI Institutional Investments Trust - High Yield Bond Fund, (viii) 323,764 shares of common stock owned by SEI Institutional Managed Trust - High Yield Bond Fund, (ix) 315,000 shares of common stock owned by Hampshire Credit Alpha Master Fund LP, (x) 164,334 shares of common stock owned by SEI Global Master Fund plc - The SEI High Yield Fixed Income Fund, (xi) 75,648 shares of common stock owned by U.S. High Yield Bond Fund and (xii) 74,838 shares of common stock owned by Blackrock Strategic Funds (UCITS) (all such owners of such securities, collectively, the “BSP Funds”). Benefit Street Partners L.L.C. serves as the investment adviser to each of the BSP Funds. The sole managing member of Benefit Street Partners L.L.C. is BSP Holdco, LLC. The sole member and Chief Executive Officer of BSP Holdco LLC is Thomas J. Gahan. As a result, Mr. Gahan may be deemed to have voting and investment power with respect to all of the shares of the common stock owned by the BSP Funds. The address for each of the BSP Funds and Mr. Gahan is 9 West 57th Street, Suite 4920, New York, New York 10019. Pursuant to the Stockholders Agreement, Benefit Street Partners has the right to designate a director for nomination to our board of directors. Mr. Buckley currently serves as Benefit Street Partners’ designee. For more information, please read “Certain Relationships and Related Party Transactions.”

(5) Consists of (i) 487,864 shares of common stock held by CarVal GCF Lux Securities S.à r.l., (ii) 803,348 shares of common stock held by CVI AA Lux Securities S.à r.l., (iii) 158,226 shares of common stock held by CVI AV Lux Securities S.à r.l., (iv) 1,191,224 shares of common stock held by CVIC Lux Securities Trading S.à r.l., (v) 3,193,056 shares of common stock held by CVI CVF III Lux Securities S.à r.l. and (vi) 721,924 shares of common stock held by CVI CVF IV Lux Securities S.à r.l. (collectively, the "CarVal funds”). Cécile Gadisseur and Paul Vermaak, in their position as managers of the CarVal funds, may be deemed to share voting and investment power over the shares held by each of the CarVal funds. CarVal Investors, LLC (the “Investment Manager”) serves as the investment manager to each of the CarVal funds. The Investment Manager and each of the directors of CarVal funds disclaim beneficial ownership of the common shares held by the CarVal funds. The address for the foregoing persons is 11-13 Boulevard de la Foire, Luxembourg, L-1528.

(6) Consists of (i) 583,153 shares of common stock owned by Signature Diversified Yield II Fund, (ii) 366,447 shares of common stock owned by CI Income Fund, (iii) 42,052 shares of common stock owned by Signature High Yield Bond II Fund, (iv) 218,919 shares of common stock owned by Signature Global Income & Growth Fund, (v) 103,918 shares of common stock owned by Signature Diversified Yield Corporate Class, (vi) 9,190 shares of common stock owned by CI US Income US$ Pool, (vii) 4,369 shares of common stock owned by Signature Tactical Bond Pool, (viii) 302,695 shares of common stock owned by Signature Income & Growth Fund, (ix) 1,417,393 shares of common stock owned by Signature High Income Fund, (x) 587,834 shares of common stock owned by Signature Corporate Bond Fund, (xi) 117,232 shares of common stock owned by Canadian Fixed Income Pool, (xii) 2,591 shares of common stock owned by Canadian Fixed Income Pool DD, (xiii) 35,380 shares of common stock owned by Enhanced Income Pool, (xiv) 32,361 shares of common stock owned by Enhanced Income Corporate Class and (xv) 109 shares of common stock owned by Skylon Growth & Income Trust, (collectively, the “CI funds”). CI Investments Inc. is the investment manager of the CI Funds. Caitlin Dean, in her position as SVP Portfolio Operations and COO of Funds of CI Investments Inc., and Geof Marshall, as Portfolio Manager of CI Investments, Inc., may be deemed to have voting and investment power with respect to the common stock owned by the CI Funds.

(7) Consists of (i) 2,291,920 shares of common stock owned by Goldman Sachs Trust—Goldman Sachs High Yield Fund, (ii) 1,357,133 shares of common stock owned by Goldman Sachs Trust—Goldman Sachs Tactical Tilt Overlay Fund, (iii) 1,033,035 shares of common stock owned by Energy Investment Opportunities Offshore WTI Ltd, (iv) 1,296,719 shares of common stock owned by Energy Investment Opportunities LLC, (v) 584,792 shares of common stock owned by Global High Yield Portfolio II WTI Ltd, (vi) 62,021 shares of common stock owned by EIOF PIV WTI Ltd, (vii) 121,127 shares of common stock owned by Factory Mutual Insurance Company, (viii) 146,596 shares of common stock owned by Tactical Tilt Overlay LLC and (ix) 2,428 shares of common stock owned by Insurance Company of the West, (collectively, the “GSAM funds and accounts”). Goldman Sachs Asset Management L.P. serves as the investment manager to each of the GSAM funds and accounts. The Fixed Income Portfolio Management Team of Goldman Sachs Asset Management, L.P., may be deemed to have voting and investment power with respect to the common stock held by the GSAM funds and accounts. The address for the foregoing persons is 200 West Street, 3rd Floor, New York, NY 10282.

(8) Douglas F. DeMuth is the managing member of Jackson Valley Fund LP and has voting and investment power over the shares held by Jackson Valley Fund LP.

(9) Consists of (i) 189,829 shares of common stock owned by Marathon Credit Dislocation Fund, LP, (ii) 822,863 shares of common stock owned by Marathon Special Opportunity Master Fund, Ltd., (iii) 219,636 shares of common stock owned by TRS Credit Fund, LP, (iv) 180,130 shares of common stock owned by Marathon Blue Grass Credit Fund, LP and (v) 545,916 shares of common stock owned by Marathon Centre Street Partnership, LP, (collectively, the “Marathon funds”). Marathon Asset Management L.P. (“Marathon”) is the investment advisor to each of the Marathon funds. The general partner of Marathon is Marathon Asset Management GP, L.L.C. Louis Hanover is a managing member of Marathon Asset Management GP, L.L.C. and may be deemed to have voting and investment power with respect to the common stock owned by the Marathon funds.

(10) Consists of 384,843 shares of common stock held by Merrill Lynch, Pierce, Fenner and Smith Incorporated (“MLPFS”), a majority-owned subsidiary of Bank of America Corporation, a publicly traded reporting company under the Exchange Act. Frank Kotsen, Head of The Global Credit and Special Situations Group (“GCSS”), a business division within MLPFS, and Michael Lee, Head of GCSS Distressed Trading, may be deemed to share voting and investment power with respect to the common stock held by MLPFS. Messrs. Kotsen and Lee disclaim beneficial ownership of the shares. MLPFS and its affiliates are full-service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. MLPFS or its affiliates have provided, and may in the

future provide, such services to us and to persons and entities with relationships with us, for which they may receive or will receive customary fees and expenses.

(11) Consists of (i) 5,531,482 shares of common stock held by Oaktree Opportunities Fund X Holdings (Delaware), L.P. (“Fund X Delaware”) and (ii) 2,262,868 shares of common stock held by Oaktree Value Opportunities Fund Holdings, L.P. (“VOF Holdings”). Oaktree Fund GP, LLC (“Fund GP”) is the general partner of Fund X Delaware; Oaktree Value Opportunities Fund GP, L.P. (“VOF GP”) is the general partner of VOF Holdings; Oaktree Value Opportunities Fund GP Ltd. (“VOF GP Ltd.”) is the general partner of VOF GP; Oaktree Fund GP I, L.P. (“GP I”) is the managing member of Fund GP and the sole shareholder of VOF GP Ltd.; Oaktree Capital I, L.P. (“Capital I”) is the general partner of GP I; OCM Holdings I, LLC (“Holdings I”) is the general partner of Capital I; Oaktree Holdings, LLC (“Holdings”) is the managing member of Holdings I; Oaktree Capital Management, L.P. (“Management”) is the sole director of VOF GP Ltd.; Oaktree Holdings, Inc. (“Holdings, Inc.”) is the general partner of Management; Oaktree Capital Group, LLC (“OCG”) is the managing member of Holdings and the sole shareholder of Holdings, Inc.; and Oaktree Capital Group Holdings GP, LLC (“OCGH GP”) is the duly elected manager of OCG. The members of OCGH GP are Howard S. Marks, Bruce A. Karsh, Jay S. Wintrob, John B. Frank and Sheldon M. Stone. The address for the foregoing persons is 333 South Grand Avenue, 28th Floor, Los Angeles, CA 90071. Pursuant to the Stockholders Agreement, Oaktree Capital Management previously had the right to designate a director for nomination to our board of directors. For more information, please read “Certain Relationships and Related Party Transactions.”

(12) South Dakota Investment Council manages the investment of South Dakota Retirement System assets. Matthew L. Clark, in his position as the State Investment Officer, has voting and investment power over the South Dakota Retirement System assets and has voting and investment power over the shares.

(13) Consists of (i) 349,124 shares of common stock held by Raven Holdings II, L.P., (ii) 1,532,860 shares of common stock held by Venor Capital Master Fund Ltd. and (iii) 1,211,857 shares of common stock held by Venor Special Situations Fund II LP, (collectively, the “Venor funds”). Venor Capital Management LP serves as the Investment Manager of Raven Holdings II, L.P., Venor Capital Master Fund Ltd. and Venor Special Situations Fund II LP. Michael Wartell and Jeffrey Bersh, the co-chief investment officers of Venor Capital Management LP, may be deemed to have shared voting and investment power over the shares held by the Venor funds.

(14) Consists of (i) 492,494 shares of common stock held by Western Asset Opportunistic US$ High Yield Securities Portfolio, L.L.C., (ii) 177,069 shares of common stock held by Stichting Pensioenfonds DSM Nederland, (iii) 243,795 shares of common stock held by Western Asset Funds, Inc. - Western Asset High Yield Fund, (iv) 36,143 shares of common stock held by Consulting Group Capital Markets Funds - High Yield Investments, (v) 193,156 shares of common stock held by Legg Mason Western Asset US High Yield Fund, (vi) 47,853 shares of common stock held by Employees' Retirement System of the State of Hawaii, (vii) 198,479 shares of common stock held by Kern County Employees' Retirement Association, (viii) 391,651 shares of common stock held by Western Asset High Income Opportunity Fund Inc., (ix) 416,915 shares of common stock held by John Hancock Funds II High Yield Fund, (x) 195,481 shares of common stock held by John Hancock Variable Insurance Trust High Yield Trust, (xi) 166,055 shares of common stock held by Brighthouse Funds Trust II - Western Asset Management Strategic Bond Opportunities Portfolio, (xii) 135,551 shares of common stock held by Legg Mason Partners Income Trust - Western Asset Global High Yield Bond Fund, (xiii) 126,186 shares of common stock held by Legg Mason Western Asset Global High Yield Bond Fund, (xiv) 305,744 shares of common stock held by Western Asset Global High Income Fund Inc., (xv) 370,182 shares of common stock held by Western Asset High Income Fund II Inc., (xvi) 65,226 shares of common stock held by Legg Mason Partners Variable Income Trust - Western Asset Variable Global High Yield Bond Portfolio, (xvii) 542,523 shares of common stock held by Western Asset Short Duration High Income Fund, (xviii) 43,936 shares of common stock held by Legg Mason Partners Income Trust - Western Asset Income Fund, (xix) 145,954 shares of common stock held by Southern California Edison Company Retirement Plan Trust, (xx) 172,752 shares of common stock held by Western Asset Strategic US$ High Yield Portfolio, L.L.C., (xxi) 74,788 shares of common stock held by International Union, UAW Strike Trust, (xxii) 116,613 shares of common stock held by WA High Income Corporate Bond (Multi-Currency) Fund, (xxiii) 233,094 shares of common stock held by Western Asset High Yield Defined Opportunity Fund Inc., (xxiv) 8,479 shares of common stock held by Western Asset Multi-Asset Credit Portfolio Master Fund, Ltd., (xxv) 187,640 shares of common stock held by Western Asset Short-Dated High Yield Master Fund, Ltd., (xxvi) 59,778 shares of common stock held by International Union, UAW Master Pension Trust, (xxvii) 360,858 shares of common stock held by Western Asset Middle Market Debt Fund, Inc., (xxviii) 46,846 shares of common stock held by Ascension Alpha Fund, LLC, (xxix) 8,617 shares of common stock held by Anthem Health Plans, Inc., (xxx) 39,106 shares of common stock held by Western Asset Funds, Inc. - Western Asset Macro Opportunities Fund, (xxxi) 34,986 shares of common stock held by Ascension Healthcare Master Pension Trust, (xxxii) 13,656 shares of common stock held by Kaiser Foundation Hospitals, (xxxiii) 9,238 shares of common stock held by Kaiser Permanente Group Trust, (xxxiv) 3,213 shares of common stock held by The Walt Disney Company Retirement Plan Master Trust, (xxxv) 123,213 shares of common stock held by VantageTrust III Master Collective Investment Funds Trust, (xxxvi) 730,306 shares of common stock held by Western Asset Middle Market Income Fund Inc., (xxxvii) 8,033 shares of common stock held by Hand Composite Employee Benefit Trust - Western Asset Income CIF, (xxxviii) 3,555 shares of common stock held by JNL Multi-Manager Alternative Fund, (xxxix) 11,312 shares of common stock held by Western Asset Premier Bond Fund, (xl) 6,267 shares of common stock held by John Lewis Partnership Pensions Trust, (xli) 42,640 shares of common stock held by Legg Mason Western Asset Global Multi Strategy Fund, (xlii) 12,183 shares of common stock held by Diageo Pension Trust Limited, (xliii) 391 shares of common stock held by Legg Mason Western Asset Short Duration High Income Bond Fund, (xliv) 2,350 shares of common stock held by GuideStone Funds Global Bond Fund, (xlv) 33,068 shares of common stock held by Legg Mason IF Western Asset Global Multi Strategy Bond Fund, (xlvi) 838 shares of common stock held by Western Asset High Yield Credit Energy Portfolio, LLC and (xlvii) 111,989 shares of common stock held by Stichting Pensioenfonds Sabic (collectively, the “WAMC funds”). Western Asset Management Company, LLC is the investment manager of the WAMC funds and may be deemed to have voting and investment power with respect to the shares of common stock owned by the WAMC funds. The address for the foregoing persons is 385 E. Colorado Blvd. Pasadena, CA 91101.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

In connection with our emergence from bankruptcy, we entered into agreements with certain of our affiliates and with parties who received shares of our common stock and Series A Preferred Stock in exchange for their claims. We have filed copies of certain of the agreements referenced in this section as exhibits to the registration statement of which this prospectus is a part.

Initial Public Offering and Purchases of Common Stock

In July 2018, we completed our IPO and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY. We received approximately $111 million of net proceeds, after deducting underwriting discounts and offering expenses payable by us, for the 8,695,653 shares of common stock issued for our benefit in the IPO, net of the shares sold for the benefit of certain selling stockholders. The price to the public for the shares sold in our IPO was $14.00 per share.

In connection with the IPO, on July 17, 2018, we entered into stock purchase agreements with certain funds affiliated with Oaktree Capital Management and Benefit Street Partners, pursuant to which we purchased an aggregate of 410,229 and 1,391,967 shares of our common stock, respectively, or 1,802,196 in total. Prior to the IPO, funds affiliated with Benefit Street Partners and Oaktree Capital Management held 19,980,658 shares (or 27.5%) and 8,088,900 shares (or 11.1%) of our outstanding common stock, respectively, assuming consummation of the Series A Preferred Stock Conversion. Immediately following the IPO and the purchase of our common stock from funds affiliated with Benefit Street Partners and Oaktree Capital Management, funds affiliated with Benefit Street Partners and Oaktree Capital Management held 18,588,691 shares (or 22.9%) and 7,678,671 shares (or 9.4%) of our outstanding common stock, respectively. In addition to the 8,695,653 shares of common stock issued and sold for our benefit in the IPO, we simultaneously received $24 million for issuing and selling 1,802,196 shares to the public and paid $24 million to purchase 1,802,196 shares under the stock purchase agreements. We purchased the shares immediately following the closing of the IPO and retired and returned them to the status of authorized but unissued shares.

The selling shareholders sold an additional 2,545,630 shares at a price to the public of $14.00 per share, for which we did not receive any proceeds.

Registration Rights Agreement

On the Effective Date, Berry Corp. entered into a Registration Rights Agreement with the members of the Ad Hoc Committee. The Registration Rights Agreement was amended and restated in connection with the IPO. For additional information about the Registration Rights Agreement, see “Description of Capital Stock” below.

Stockholders Agreement

On the Effective Date, Berry Corp. and the members of the Ad Hoc Committee entered into a Stockholders Agreement governing the election of directors to the board of directors of Berry Corp. and other governance matters. The Stockholders Agreement was amended and restated in connection with the IPO. For additional information about the Stockholders Agreement, see “Description of Capital Stock” below.

Transactions with Linn Energy

Transition Services and Separation Agreement

On the Effective Date, Berry LLC entered into a Transition Services and Separation Agreement (the “TSSA”) with Linn Energy and certain of Linn Energy’s affiliates and subsidiaries to facilitate the separation of our operations from Linn Energy’s operations. Pursuant to the TSSA, (i) Linn Energy was required to provide, or cause to be provided, certain administrative, management, operating, and other services and support (the “Transition Services”) to us for the period from the Effective Date through the last day of the second full calendar month after the Effective Date (the “Transition Period”), (ii) we and the Linn Energy debtors separated our previously combined enterprise and (iii) the

Linn Energy debtors transferred to us certain assets that related to our properties or business, in each case under the terms and conditions specified in the TSSA.

Under the TSSA, we reimbursed Linn Energy for any and all reasonable, third-party out-of-pocket costs and expenses, without markup, actually incurred by Linn Energy, to the extent documented, in connection with providing the Transition Services. Additionally, we paid Linn Energy a management fee of $6 million per month, prorated for partial months, during the Transition Period and paid $2.7 million per month, prorated for partial months, from the first day following the Transition Period through the last day of the second full calendar month thereafter (the "Separation Period"). During the Separation Period, the scope of the Transition Services was reduced to specified accounting and administrative functions. The Transition Period under the TSSA ended April 30, 2017, and the Separation Period ended June 30, 2017.

One of Linn Energy's former directors is the President and Chief Executive Officer of Superior Energy Services, Inc. ("Superior"), which provided oilfield services to Berry LLC. Berry LLC incurred no significant expenditures related to services rendered by Superior and its subsidiaries for the year ended December 31, 2016.

Operating Agreements

On the Effective Date, in connection with the TSSA, Berry LLC and Linn Holdings entered into two Operating Agreements governing the joint ownership and operation of certain oil and natural gas assets with respect to which Berry LLC and Linn Holdings, either directly or through an affiliate, would continue to have joint ownership after the Effective Date.

Pursuant to an operating agreement, Linn Operating operated the Hugoton assets as agent for Linn Holdings (which owned a working interest in the Hugoton assets).

Pursuant to an operating agreement, Berry LLC operated the Hill assets after the Effective Date until we purchased the assets on July 31, 2017.

Nick Smith Employment Agreement

We currently employ Nick Smith, the son of A. T. (Trem) Smith, our Chief Executive Officer, as Director of Strategic Planning & Commercial Marketing. Consistent with market rates of compensation, Mr. Smith received a salary of $216,000, stock awards with a grant date fair value of $42,000, non-equity incentive plan compensation of $22,000, tax reimbursement amounts of $560 and other compensation of $12,000 from October 1, 2017 through September 30, 2018.

Procedures for Approval of Interested Transactions

We have adopted a policy for approval of Interested Transactions. An "Interested Transaction" is a transaction, arrangement or relationship or series of similar transactions, arrangements or relationships (including any indebtedness or guarantee of indebtedness) in which we are a participant, the aggregate amount of which involved exceeds or may be expected to exceed $120,000 in any calendar year, and in which any Related Person, has or will have a direct or indirect interest (other than solely as a result of being a director or less than 10% beneficial owner of another entity). A "Related Person" means:

- a director or director nominee of the Company;
- a senior officer of the Company, which, among others, includes each vice president and officer of the Company that is subject to reporting under Section 16 of the Exchange Act;
- a stockholder owning more than 5% of the Company or its controlled affiliates (a "5% Stockholder");

- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, director nominee, senior officer or 5% Stockholder, and any person (other than a tenant or employee) sharing the household of such director, director nominee, senior officer or 5% Stockholder; and

- any entity that is owned or controlled by someone listed above, or an entity in which someone listed above has a substantial ownership interest or control of the entity.

Pursuant to our policy, our audit committee will review all material facts of all Interested Transactions and either approve or disapprove entry into the Interested Transaction, subject to certain limited exceptions. If advance audit committee approval of an Interested Transaction is not feasible, then the Interested Transaction should be considered and ratified (if the audit committee determines it to be appropriate) at the audit committee's next regularly scheduled meeting. In determining whether to approve or ratify entry into an Interested Transaction, our audit committee shall take into account, among other factors, the following: (i) whether the Interested Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances; (ii) the extent of the Related Person's interest in the transaction; and (iii) whether the Interested Transaction is material to the Company.

DESCRIPTION OF CAPITAL STOCK

Berry Corp.'s authorized capital stock consists of 750,000,000 shares of common stock, par value $0.001 per share, and 250,000,000 shares of preferred stock, par value $0.001 per share. As of November 29, 2018, there were 81,651,098 shares of common stock and no shares of Series A Preferred Stock outstanding.

The following summary of the capital stock and the Certificate of Incorporation and Bylaws of Berry Corp. does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to the Certificate of Incorporation and Bylaws, which are filed as exhibits to the registration statement of which this prospectus is a part.

Common Stock

Dividends

Holders of the common stock are entitled to dividends in the amounts and at the times declared by Berry Corp.'s board of directors in its discretion out of any assets or funds of Berry Corp. legally available for the payment of dividends.

Voting

Each holder of shares of the common stock is entitled to one vote for each share of the common stock on all matters presented to the stockholders of Berry Corp. (including the election of directors). The holders of shares of common stock have no cumulative voting rights. All elections of directors are determined by a plurality of the votes cast, and except as otherwise required by law or by the rules of any stock exchange upon which Berry Corp.'s securities are listed or as otherwise provided in the Bylaws or Certificate of Incorporation, all other matters are determined by a majority of the votes cast affirmatively or negatively, on such matter. Action required or permitted to be taken at an annual or special meeting of stockholders may be taken without a meeting or vote if a written consent setting forth the action is signed by at least the minimum number of votes necessary to authorize or take such action at a meeting.

Liquidation

The holders of the common stock will share equally and ratably in Berry Corp.'s assets on liquidation after payment or provision for all liabilities and any preferential liquidation rights of any preferred stock then outstanding.

Other Rights

The holders of the common stock do not have preemptive rights to purchase shares of Berry Corp.'s stock. The common stock is not convertible, redeemable, assessable or entitled to the benefits of any sinking or repurchase fund. The rights, preferences and privileges of holders of the common stock will be subject to those of the holders of any shares of preferred stock that Berry Corp. may issue in the future.

Under the terms of the Certificate of Incorporation, Berry Corp. is prohibited from issuing any non-voting equity securities to the extent required under Section 1123(a)(6) of the Bankruptcy Code and only for so long as Section 1123 of the Bankruptcy Code is in effect and applicable to Berry Corp.

Limitation of Liability of Directors and Indemnification Matters

The Certificate of Incorporation provides that no director shall be personally liable to Berry Corp. or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (i) for any breach of the director's duty of loyalty to Berry Corp. or its stockholders, (ii) for any act or omission not in good faith or which involves intentional misconduct or a knowing violation of law, (iii) under Section 174 of the DGCL or (iv) for any transaction from which the director derived an improper personal benefit. The effect of this provision is to eliminate Berry Corp.'s and its stockholders' rights, through stockholders' derivative suits on Berry Corp.'s behalf, to recover monetary damages against a director for certain breaches of fiduciary duty as a director.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Berry Corp. has entered into indemnification agreements with each of its directors and executive officers. These indemnification agreements require Berry Corp. to indemnify these individuals to the fullest extent permitted under Delaware law against liabilities that may arise by reason of their service as a director or executive officer of Berry Corp. In addition, Berry Corp. is also required to advance expenses incurred by such individuals in connection with any proceeding arising by reason of their service. The Certificate of Incorporation also provides that we will indemnify our directors and officers to the fullest extent permitted under Delaware law.

Anti-Takeover Provisions of the Certificate of Incorporation, the Bylaws and the DGCL

The Certificate of Incorporation, the Bylaws and the DGCL contain provisions that may have some anti-takeover effects and may delay, defer or prevent a takeover attempt or a removal of Berry Corp.'s incumbent officers or directors that a stockholder might consider in his, her or its best interest, including those attempts that might result in a premium over the market price for shares held by the stockholders.

Delays in or Prevention of a Change in Control

Provisions in Berry Corp.'s Bylaws could have an effect of delaying, deferring or preventing a change in control of Berry Corp.

Preferred Stock

The Certificate of Incorporation authorizes our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.001 per share, covering up to an aggregate of 250,000,000 shares of preferred stock. The board of directors may determine the number of shares in each such series and fix the designation, powers, preferences, rights, qualifications, limitations and restrictions of such series. The number of authorized shares of preferred stock may be increased or decreased by the affirmative vote of the holders of a majority of the voting power of all then-outstanding shares of capital stock of Berry Corp. entitled to vote thereon, without a vote of the holders of the preferred stock, or of any series thereof, unless a vote of any such holders is required pursuant to the terms of any preferred stock designation.

Amendment of the Bylaws

The Certificate of Incorporation and the Bylaws grant to the board of directors the power to adopt, amend, restate or repeal the Bylaws, as permitted under the DGCL, provided that no bylaw adopted by the stockholders may be amended, repealed or readopted by the board of directors if such bylaw so provides. The stockholders may adopt, amend, restate or repeal the Bylaws but only by a vote of holders of a majority in voting power of the outstanding shares of stock entitled to vote thereon, voting together as a single class in addition to any approval required by law, the Bylaws or the terms of any preferred stock.

Other Limitations on Stockholder Actions

- Advance notice is required for stockholders to nominate directors or to submit proposals for consideration at meetings of stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date we first mailed our proxy materials for the annual meeting for the preceding year. The Bylaws specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting,

- Directors may be removed from office, either for or without cause, by the affirmative vote of the holders of a majority of the voting power of the then-outstanding shares of capital stock entitled to vote generally in the election of directors).

- Stockholders may call a special meeting only upon request of at least 25% of the voting power of the shares entitled to vote in the election of directors.

Forum Selection

The Certificate of Incorporation generally provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for:

- any derivative action or proceeding brought on our behalf;

- any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers or other employees to us or our stockholders;

- any action asserting a claim against us or our directors, officers or employees arising pursuant to any provision of the DGCL, our Certificate of Incorporation or Bylaws; or

- any action asserting a claim against us or our directors, officers or employees that is governed by the internal affairs doctrine;

in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Although we believe these provisions will benefit us by providing increased consistency in the application of Delaware law for the specified types of actions and proceedings, the provisions may have the effect of discouraging lawsuits against our directors, officers, employees and agents. The enforceability of similar exclusive forum provisions in other companies' certificates of incorporation has been challenged in legal proceedings, and it is possible that, in connection with one or more actions or proceedings described above, a court could rule that this provision in the Certificate of Incorporation is inapplicable or unenforceable.

Corporate Opportunity

Under the Certificate of Incorporation, to the extent permitted by law:

- our stockholders are permitted to make investments in competing businesses;

- if a Dual Role Person becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us; and

- we have renounced our interest in, or in being offered an opportunity to participate in, such corporate opportunities presented to a Dual Role Person.

Newly Created Directorships and Vacancies on the Board of Directors

Under the Bylaws, and subject to the Stockholders Agreement, any vacancies on the board of directors for any reason and any newly created directorships resulting from any increase in the number of directors may be filled (i) by the board of directors upon a vote of a majority of the remaining directors then in office, even if they constitute less than a quorum of the board of directors or by a sole remaining director or (ii) by the stockholders at a special or annual meeting or by written consent of holders of a majority of the voting power of the shares entitled to vote in connection with the election of the directors, voting together as a single class.

Registration Rights

The Registration Rights Agreement generally requires us to file a shelf registration statement with the SEC as soon as practicable. This registration statement is being filed pursuant to our obligations under the Registration Rights Agreement. Consistent with our obligations under the Registration Rights Agreement, this registration statement registers the resale, on a delayed or continuous basis, of all Registrable Securities that have been timely designated for inclusion by the holders (specified in the Registration Rights Agreement). Generally, “Registrable Securities” includes (i) common stock we issued under the Plan and (ii) common stock into which the Series A Preferred Stock was converted, except that “Registrable Securities” does not include securities that have been sold under an effective registration statement or Rule 144 under the Securities Act or securities that have been transferred to a person other than a specified holder or a valid transferee.

The Registration Rights Agreement also requires us to effect demand registrations, which the specified holders may request to be underwritten, and underwritten shelf takedowns from the initial shelf registration if requested by holders of a specified percentage of Registrable Securities, subject to customary conditions and restrictions. If Registrable Securities are to be distributed in an underwritten public offering and our common stock is not then listed on a national securities exchange or quoted on a recognized trading market, we must use commercially reasonable efforts to cause the Registrable Securities to be listed on a national securities exchange as promptly as practicable.

If we propose to file a registration statement under the Securities Act or conduct a shelf takedown with respect to a public offering of any class of our equity securities, the specified holders have “piggyback” registration rights to include their Registrable Securities in the registration statement, including in this offering, subject to customary conditions and restrictions.

At any time when we are required to file public reports with the SEC under the Securities Act or the Exchange Act, the Registration Rights Agreement requires us to use commercially reasonable efforts to timely comply with the reporting requirements. If we are not subject to these reporting requirements, we must make available information necessary for the specified holders of Registrable Securities to resell their Registrable Securities in compliance with Section 4(a)(7), Rule 144, Rule 144A and Regulation S, if available, without registration under the Securities Act and within the limitations of the applicable exemptions.

The Registration Rights Agreement will terminate when there are no longer any Registrable Securities outstanding. As of November 5, 2018, there were 61,977,483 shares of our common stock outstanding that were owned by stockholders with rights under the Registration Rights Agreement.

Stockholders Agreement

Under the Stockholders Agreement, we are required to take all necessary action to cause the following two individuals to be nominated for election as directors of Berry Corp.:

- the individual serving as our Chief Executive Officer; and

- one individual designated by Benefit Street Partners (for so long as Benefit Street Partners beneficially owns at least ten percent of the common stock beneficially owned by all of the parties to the Stockholders Agreement).

Benefit Street Partners has the right under the Stockholders Agreement to designate a director to fill any vacancy created by the resignation or removal of its designee. Oaktree Capital Management also previously had the right to designate one individual for nomination for election as director, but effective September 12, 2018, Oaktree Capital Management relinquished this right under the Stockholders Agreement.

Under the Stockholders Agreement, no member of the Stockholder Group, nor any of their affiliates, will have any liability as a result of designating or nominating an individual to serve as a director for us, solely for any act or omission by such individual in her or her capacity as a director in accordance with the terms of the Stockholders Agreement.

The Stockholders Agreement will terminate automatically on February 28, 2020. The Stockholders Agreement may be terminated earlier by written agreement between us and the members of the Stockholder Group owning at least a majority of the common stock then beneficially owned by all members of the Stockholder Group; provided, however, except that any early termination also requires the written agreement of any member of the Stockholder Group that then has a right to appoint a director under the Stockholders Agreement.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company, LLC ("AST"). AST's address is 6201 15th Avenue, Brooklyn, New York 11219, and AST's phone number is (718) 921-8200.

Listing

Our common stock is listed on the NASDAQ under the symbol "BRY."

MATERIAL U.S. FEDERAL INCOME TAX CONSIDERATIONS FOR NON-U.S. HOLDERS

The following is a summary of the material U.S. federal income tax considerations related to the purchase, ownership and disposition of our common stock by a non-U.S. holder (as defined below), that holds our common stock as a “capital asset” (generally property held for investment). This summary is based on the provisions of the Code, U.S. Treasury regulations, administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change or differing interpretations, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service (“IRS”) with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS or a court will agree with such statements and conclusions.

This summary does not address all aspects of U.S. federal income taxation that may be relevant to non-U.S. holders in light of their personal circumstances. In addition, this summary does not address the Medicare tax on certain investment income, U.S. federal estate or gift tax laws, any state, local or non-U.S. tax laws or any tax treaties. This summary also does not address tax considerations applicable to investors that may be subject to special treatment under the U.S. federal income tax laws, such as:

- banks, insurance companies or other financial institutions;
- tax-exempt or governmental organizations;
- qualified foreign pension funds (or any entities all of the interests of which are held by a qualified foreign pension fund);
- dealers in securities or foreign currencies;
- traders in securities that use the mark-to-market method of accounting for U.S. federal income tax purposes;
- persons subject to the alternative minimum tax;
- partnerships or other pass-through entities for U.S. federal income tax purposes or holders of interests therein;
- persons deemed to sell our common stock under the constructive sale provisions of the Code;
- persons that acquired our common stock through the exercise of employee stock options or otherwise as compensation or through a tax-qualified retirement plan;
- certain former citizens or long-term residents of the United States; and
- persons that hold our common stock as part of a straddle, appreciated financial position, synthetic security, hedge, conversion transaction or other integrated investment or risk reduction transaction.

PROSPECTIVE INVESTORS ARE ENCOURAGED TO CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATION, AS WELL AS ANY TAX CONSEQUENCES OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF OUR COMMON STOCK ARISING UNDER THE U.S. FEDERAL ESTATE OR GIFT TAX LAWS OR UNDER THE LAWS OF ANY STATE, LOCAL, NON-U.S. OR OTHER TAXING JURISDICTION OR UNDER ANY APPLICABLE INCOME TAX TREATY.

Non-U.S. Holder Defined

For purposes of this discussion, a “non-U.S. holder” is a beneficial owner of our common stock that is not for U.S. federal income tax purposes a partnership or any of the following:

- an individual who is a citizen or resident of the United States;

- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;

- an estate the income of which is subject to U.S. federal income tax regardless of its source; or

- a trust (i) the administration of which is subject to the primary supervision of a U.S. court and which has one or more United States persons who have the authority to control all substantial decisions of the trust or (ii) which has made a valid election under applicable U.S. Treasury regulations to be treated as a United States person.

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership generally will depend upon the status of the partner, upon the activities of the partnership and upon certain determinations made at the partner level. Accordingly, we urge partners in partnerships (including entities or arrangements treated as partnerships for U.S. federal income tax purposes) considering the purchase of our common stock to consult their tax advisors regarding the U.S. federal income tax considerations of the purchase, ownership and disposition of our common stock by such partnership.

Distributions

Distributions of cash or property on our common stock, if any, will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those distributions exceed our current and accumulated earnings and profits, the distributions will be treated as a non-taxable return of capital to the extent of the non-U.S. holder's tax basis in our common stock and thereafter as capital gain from the sale or exchange of such common stock. See "—Gain on Disposition of Common Stock." Subject to the withholding requirements under FATCA (as defined below) and with respect to effectively connected dividends, and subject to the discussion below under "—Backup Withholding and Information Reporting," each of which is discussed below, any distribution made to a non-U.S. holder on our common stock generally will be subject to U.S. withholding tax at a rate of 30% of the gross amount of the distribution unless an applicable income tax treaty provides for a lower rate. To receive the benefit of a reduced treaty rate, a non-U.S. holder must timely provide the applicable withholding agent with an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form) certifying qualification for the reduced rate.

Dividends paid to a non-U.S. holder that are effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, are treated as attributable to a permanent establishment maintained by the non-U.S. holder in the United States) generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code). Subject to the discussion below under "—Backup Withholding and Information Reporting" and "—Additional Withholding Requirements under FATCA," such effectively connected dividends will not be subject to U.S. withholding tax if the non-U.S. holder satisfies certain certification requirements by providing the applicable withholding agent with a properly executed IRS Form W-8ECI certifying eligibility for exemption. If the non-U.S. holder is a corporation for U.S. federal income tax purposes, it may also be subject to a branch profits tax (at a 30% rate or such lower rate as specified by an applicable income tax treaty) on its effectively connected earnings and profits (as adjusted for certain items), which will include effectively connected dividends.

Gain on Disposition of Common Stock

Subject to the discussions below under "—Backup Withholding and Information Reporting" and "—Additional Withholding Requirements under FATCA," a non-U.S. holder generally will not be subject to U.S. federal income or withholding tax on any gain realized upon the sale or other disposition of our common stock unless:

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met;

- the gain is effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States); or

- we are or have been a United States real property holding corporation ("USRPHC") for U.S. federal income tax purposes during the applicable statutory period and either (a) our common stock is not "regularly traded on an established securities market" (within the meaning of U.S. Treasury Regulations) or (b) our common stock is "regularly traded on an established securities market" (within the meaning of U.S. Treasury Regulations) and the non-U.S. holder owns, or owned at any time during the shorter of the five-year period ending on the date of the disposition or the non-U.S. holder's holding period for the common stock, more than 5% of our common stock.

A non-U.S. holder described in the first bullet point above will be subject to U.S. federal income tax at a rate of 30% (or such lower rate as specified by an applicable income tax treaty) on the amount of such gain, which generally may be offset by U.S. source capital losses.

A non-U.S. holder whose gain is described in the second bullet point above or, subject to the exceptions described in the next paragraph, the third bullet point above, generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code) unless an applicable income tax treaty provides otherwise. If the non-U.S. holder is a corporation for U.S. federal income tax purposes whose gain is described in the second bullet point above, then such gain would also be included in its effectively connected earnings and profits (as adjusted for certain items), which may be subject to a branch profits tax (at a 30% rate or such lower rate as specified by an applicable income tax treaty).

Generally, a corporation is a USRPHC if the fair market value of its "United States real property interests" (within the meaning of the Code and the applicable U.S. Treasury Regulations) equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, as long as our common stock continues to be "regularly traded on an established securities market" (within the meaning of the U.S. Treasury Regulations), only a non-U.S. holder that actually or constructively owns, or owned at any time during the shorter of the five-year period ending on the date of the disposition or the non-U.S. holder's holding period for the common stock, more than 5% of our common stock will be treated as disposing of a U.S. real property interest and will be taxable on gain realized on the disposition of our common stock as a result of our status as a USRPHC. We believe that, for as long as our common stock is listed on a national securities exchange, our common stock will be treated as regularly traded on an established securities market (within the meaning of the U.S. Treasury Regulations). If, however, our common stock ceased to be regularly traded on an established securities market, a non-U.S. holder (regardless of the percentage of stock owned) would be treated as disposing of a U.S. real property interest and would be subject to U.S. federal income tax on a taxable disposition of our common stock, and a 15% withholding tax would apply to the gross proceeds from such disposition. If a non-U.S. holder is subject to the tax described in this paragraph, such non-U.S. holder will be required to file a United States federal income tax return with the IRS with respect to the year of the disposition.

Non-U.S. holders should consult their tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our common stock.

Backup Withholding and Information Reporting

Any dividends paid to a non-U.S. holder must be reported annually to the IRS and to the non-U.S. holder. Copies of these information returns may be made available to the tax authorities in the country in which the non-U.S. holder resides or is established. Payments of dividends to a non-U.S. holder generally will not be subject to backup withholding if the non-U.S. holder establishes an exemption by timely and properly certifying its non-U.S. status on an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form).

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our common stock effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form) and certain other conditions are met. Information reporting and backup withholding generally will not apply to any payment of the proceeds from a sale or other disposition of our common stock effected outside the United States by a non-U.S. office of a broker. However, unless such broker has documentary evidence in its records that the non-U.S. holder is not a United States person and certain other conditions are met, or the non-U.S. holder otherwise establishes an exemption, information reporting will apply to a payment of the proceeds of the disposition of our common stock effected outside the United States by such a broker if it has certain relationships within the United States.

Backup withholding is not an additional tax. Rather, the U.S. federal income tax liability (if any) of persons subject to backup withholding will be reduced by the amount of tax withheld, provided that the required information is timely furnished to the IRS. If backup withholding results in an overpayment of taxes, a refund may be obtained, provided that the required information is timely furnished to the IRS.

Additional Withholding Requirements under FATCA

Sections 1471 through 1474 of the Code, and the U.S. Treasury regulations and administrative guidance issued thereunder ("FATCA"), impose a 30% withholding tax on any dividends paid on our common stock and on the gross proceeds from a disposition of our common stock (if such disposition occurs after December 31, 2018), in each case if paid to a "foreign financial institution" or a "non-financial foreign entity" (each as defined in the Code) (including, in some cases, when such foreign financial institution or non-financial foreign entity is acting as an intermediary), unless (i) in the case of a foreign financial institution, such institution enters into an agreement with the U.S. government to withhold on certain payments, and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution (which includes certain equity and debt holders of such institution, as well as certain account holders that are non-U.S. entities with U.S. owners), (ii) in the case of a non-financial foreign entity, such entity certifies that it does not have any "substantial United States owners" (as defined in the Code) or provides the applicable withholding agent with a certification identifying the direct and indirect substantial United States owners of the entity (in either case, generally on an IRS Form W-8BEN-E), or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules and provides appropriate documentation (such as an IRS Form W-8BEN-E). Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these rules may be subject to different rules. Under certain circumstances, a holder might be eligible for refunds or credits of such taxes. Non-U.S. holders are encouraged to consult their own tax advisors regarding the effects of FATCA on an investment in our common stock.

INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK ARE URGED TO CONSULT THEIR OWN TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATIONS AND THE APPLICABILITY AND EFFECT OF U.S. FEDERAL ESTATE AND GIFT TAX LAWS AND ANY STATE, LOCAL OR NON-U.S. TAX LAWS AND TAX TREATIES.

PLAN OF DISTRIBUTION

The selling stockholders may, from time to time, sell, transfer or otherwise dispose of any or all of their shares or interests in the shares of common stock on any stock exchange, market or trading facility on which the shares are traded or in private transactions. The selling stockholders may sell their shares from time to time at the prevailing market price or in privately negotiated transactions. We will not receive any of the proceeds from the sale of shares of common stock pursuant to this prospectus.

The selling stockholders may use any one or more of the following methods when disposing of shares or interests therein:

- on the NASDAQ, in the over-the-counter market or on any other securities exchange on which our common stock is listed or traded;
- ordinary brokerage transactions and transactions in which the broker-dealer solicits purchasers;
- block trades in which the broker-dealer will attempt to sell the shares as agent, but may position and resell a portion of the block as principal to facilitate the transaction;
- purchases by a broker-dealer as principal and resale by the broker-dealer for its account;
- an exchange distribution in accordance with the rules of the applicable exchange;
- privately negotiated transactions;
- in underwriting transactions;
- short sales effected after the date the registration statement of which this prospectus is a part is declared effective by the SEC;
- through the writing or settlement of options or other hedging transactions, whether through an options exchange or otherwise;
- broker-dealers may agree with the selling stockholders to sell a specified number of such shares at a stipulated price per share;
- “at the market” or through market makers or into an existing market for the shares;
- a combination of any such methods of sale; and
- any other method permitted pursuant to applicable law.

The selling stockholders may sell the shares at fixed prices, at prices then prevailing or related to the then current market price or at negotiated prices. The offering price of the shares from time to time will be determined by the selling stockholders and, at the time of the determination, may be higher or lower than the market price of our common stock on the NASDAQ or any other exchange or market.

The shares may be sold directly or through broker-dealers acting as principal or agent. The selling stockholders may also enter into hedging transactions with broker-dealers. In connection with such transactions, broker-dealers of other financial institutions may engage in short sales of our common stock in the course of hedging the positions they assume with the selling stockholders. The selling stockholders may also enter into options or other transactions with broker-dealers or other financial institutions which require the delivery to such broker-dealer or other financial institution of shares offered by this prospectus, which shares such broker-dealer or other financial institution may resell pursuant to this prospectus (as supplemented or amended to reflect such transaction).

The selling stockholders may agree to indemnify an underwriter, broker-dealer or agent against certain liabilities related to the selling of their shares, including liabilities arising under the Securities Act. Under the Registration Rights Agreement for the benefit of the selling stockholders, we have agreed to indemnify the selling stockholders against certain liabilities related to the sale of the common stock, including certain liabilities arising under the Securities Act. Under the Registration Rights Agreement, we have also agreed to pay the costs, expenses and fees of registering the shares of common stock, including certain legal fees incurred by the selling stockholders. Brokers' or underwriters' discounts and commissions, if any, and all transfer taxes and transfer fees relating to the sale or disposition of the selling stockholders will be borne by the selling stockholders.

In connection with an underwritten offering, underwriters or agents may receive compensation in the form of discounts, concessions or commissions from the selling stockholders or from purchasers of the offered shares for whom they may act as agents. In addition, underwriters may sell the shares to or through dealers, and those dealers may receive compensation in the form of discounts, concessions or commissions from the underwriters and/or commissions from the purchasers for whom they may act as agents. The selling stockholders and any underwriters, broker-dealers or agents participating in a distribution of the shares may be deemed to be "underwriters" within the meaning of the Securities Act, and any profit on the sale of the shares by the selling stockholders and any commissions received by broker-dealers may be deemed to be underwriting commissions under the Securities Act. The following selling stockholder has represented to us that it is a broker-dealer: Merrill Lynch, Pierce, Fenner & Smith, Incorporated.

The selling stockholders are subject to the applicable provisions of the Exchange Act, and the rules and regulations under the Exchange Act, including Regulation M. This regulation may limit the timing of purchases and sales of any of the shares of common stock offered in this prospectus by the selling stockholders. The anti-manipulation rules under the Exchange Act may apply to sales of shares in the market and to the activities of the selling stockholders and its affiliates. Furthermore, Regulation M may restrict the ability of any person engaged in the distribution of the shares to engage in market-making activities for the particular securities being distributed for a period of up to five business days before the distribution. The restrictions may affect the marketability of the shares and the ability of any person or entity to engage in market-making activities for the shares.

To the extent required, this prospectus may be amended and/or supplemented from time to time to describe a specific plan of distribution. Instead of selling the shares of common stock under this prospectus, the selling stockholders may sell the shares of common stock in compliance with the provisions of Rule 144 under the Securities Act, if available, or pursuant to other available exemptions from the registration requirements of the Securities Act.

Under the securities laws of some states, if applicable, the securities registered hereby may be sold in those states only through registered or licensed brokers or dealers. In addition, in some states such securities may not be sold unless they have been registered or qualified for sale or an exemption from registration or qualification requirements is available and is complied with.

We cannot assure you that the selling stockholders will sell all or any portion of our common stock offered hereby.

Under the Registration Rights Agreement, we agreed to keep the registration statement of which this prospectus constitutes a part continuously effective under the Securities Act until the earlier of (i) the date on which all Registrable Securities included herein have been sold; (ii) the date on which all such securities cease to be Registrable Securities or (iii) the maximum length permitted by the SEC.

LEGAL MATTERS

The validity of our common stock offered by this prospectus will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. Any underwriters or agents will be advised about other issues relating to the offering by counsel to be named in the applicable prospectus supplement.

EXPERTS

The consolidated financial statements of Berry Petroleum Corporation and subsidiary as of December 31, 2017 (Successor) and 2016 (Predecessor), and for the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and for the year ended December 31, 2016 (Predecessor) have been included herein in reliance upon the report of KPMG LLP, independent registered public accounting firm, and upon the authority of said firm as experts in auditing and accounting. The audit report covering the December 31, 2017 consolidated financial statements refers to a change in the basis of presentation for Berry Petroleum Corporation's emergence from bankruptcy.

Certain estimates of our oil and natural gas reserves and related information included in this prospectus have been derived from reports prepared by the independent engineering firm, DeGolyer and MacNaughton. All such information has been so included on the authority of such firms as experts regarding the matters contained in their reports.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act, with respect to the shares of our common stock offered hereby. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules thereto. For further information with respect to the common stock offered hereby, we refer you to the registration statement and the exhibits and schedules filed therewith. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of such contract, agreement or other document and are not necessarily complete. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved.

We are required to file annual and quarterly reports and other information with the SEC. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. The address of the SEC's website is *www.sec.gov*.

We maintain an Internet site at www.berrypetroleum.com. We do not incorporate our Internet site, or the information contained on that site or connected to that site, into this prospectus or this registration statement.

We make available free of charge on our website, all materials that we have filed electronically with the SEC, including our quarterly reports on Form 10-Q, current reports on Form 8-K, Section 16 reports and amendments to these reports as soon as reasonably practicable after such materials are electronically filed with, or furnished to, the SEC. Our filings will also be available to the public from commercial document retrieval services and at the web site maintained by the SEC at http://www.sec.gov.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors

Berry Petroleum Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying balance sheets of Berry Petroleum Corporation and subsidiary (the “Company”) as of December 31, 2017 (Successor) and 2016 (Predecessor), the related consolidated statements of operations, statements of equity, and statements of cash flows for the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and for the year ended December 31, 2016 (Predecessor), and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 (Successor) and 2016 (Predecessor), and the results of its operations and its cash flows for the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and for the year ended December 31, 2016 (Predecessor), in conformity with U.S. generally accepted accounting principles.

Basis of Presentation

As discussed in Note 2 to the consolidated financial statements, the Company emerged from bankruptcy on February 28, 2017. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Note 2.

Basis for Opinion

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 are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

/s/ KPMG LLP

We have served as the Company’s auditor since 2013.
Los Angeles, California
April 11, 2018, except for Note 15, as to which the date is June 12, 2018

BERRY PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share amounts)

	Berry Petroleum Corporation (Successor) December 31, 2017	Berry Petroleum Company, LLC (Predecessor) December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33,905	$ 30,483
Accounts receivable, net of allowance of $970 in 2017 and $0 in 2016	54,720	51,175
Restricted cash	34,833	128
Other current assets	14,066	16,218
Total current assets	137,524	98,004
Oil and natural gas properties	1,342,453	5,026,810
Accumulated depletion and amortization	(54,785)	(2,789,368)
	1,287,668	2,237,442
Other property and equipment	104,879	123,460
Accumulated depreciation	(5,356)	(20,759)
	99,523	102,701
Restricted cash	—	197,793
Other noncurrent assets	21,687	16,110
Total assets	$ 1,546,402	$ 2,652,050
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 97,877	$ 68,998
Derivative instruments	49,949	8,896
Current portion of long-term debt	—	891,259
Liabilities subject to compromise	34,833	—
Total current liabilities	182,659	969,153
Long term debt	379,000	—
Derivative instruments	25,332	10,221
Liabilities subject to compromise	—	1,000,553
Deferred income taxes	1,888	—
Asset retirement obligation	94,509	138,751
Other noncurrent liabilities	3,704	30,409
Commitments and Contingencies - Note 7		
Equity:		
Successor Series A convertible preferred stock ($.001 par value, 250,000,000 shares authorized and 35,845,001 shares issued at December 31, 2017; no shares authorized and issued at December 31, 2016)	335,000	—
Successor common stock ($.001 par value, 750,000,000 shares authorized and 32,920,000 shares issued at December 31, 2017; no shares authorized or issued at December 31, 2016)	33	—
Successor additional paid-in-capital	545,345	—
Predecessor additional paid-in-capital	—	2,798,713
Predecessor accumulated deficit	—	(2,295,750)
Successor accumulated deficit	(21,068)	—
Total Equity	859,310	502,963
Total liabilities and equity	$ 1,546,402	$ 2,652,050

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

BERRY PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands)

	Berry Petroleum Corporation (Successor)	Berry Petroleum Company, LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Revenues and other:			
Oil, natural gas and natural gas liquids sales	$ 357,928	$ 74,120	$ 392,345
Electricity sales	21,972	3,655	23,204
(Losses) gains on oil and natural gas derivatives	(66,900)	12,886	(15,781)
Marketing revenues	2,694	633	3,653
Other revenues	3,975	1,424	7,570
	319,669	92,718	410,991
Expenses and other:			
Lease operating expenses	149,599	28,238	185,056
Electricity generation expenses	14,894	3,197	17,133
Transportation expenses	19,238	6,194	41,619
Marketing expenses	2,320	653	3,100
General and administrative expenses	56,009	7,964	79,236
Depreciation, depletion and amortization	68,478	28,149	178,223
Impairment of long-lived assets	—	—	1,030,588
Taxes, other than income taxes	34,211	5,212	25,113
(Gains) losses on sale of assets and other, net	(22,930)	(183)	(109)
	321,819	79,424	1,559,959
Other income and (expenses):			
Interest expense	(18,454)	(8,245)	(61,268)
Other, net	4,071	(63)	(182)
	(14,383)	(8,308)	(61,450)
Reorganization items, net	(1,732)	(507,720)	(72,662)
Loss before income taxes	(18,265)	(502,734)	(1,283,080)
Income tax expense	2,803	230	116
Net loss	(21,068)	$ (502,964)	$ (1,283,196)
Undeclared dividends on Series A preferred stock	(18,248)	n/a	n/a
Net loss available to common stockholders	$ (39,316)	n/a	n/a
Loss per share attributable to common stockholders:			
Basic	$ (0.98)	n/a	n/a
Diluted	$ (0.98)	n/a	n/a

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

BERRY PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Berry Petroleum Corporation (Successor)	Berry Petroleum Company, LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Cash flow from operating activities:			
Net loss	$ (21,068)	$ (502,964)	$ (1,283,196)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	68,478	28,149	178,223
Amortization of debt issuance costs	1,988	416	1,849
Impairment of long-lived asset	—	—	1,030,588
Stock-based compensation expense	1,851	—	—
Deferred income taxes	1,888	9	(11)
Increase in allowance for doubtful accounts	970	—	—
Gain on sale of assets and other, net	(22,930)	(25)	(212)
Reorganization expenses, net	—	501,872	43,289
Derivatives activities:			
Total (gains) losses	66,900	(12,886)	20,386
Cash settlements	3,068	534	8,007
Cash settlements on canceled derivatives	—	—	1,701
Changes in assets and liabilities:			
Increase in accounts receivable	(7,022)	(9,152)	(6,556)
(Increase) decrease in other assets	(13,175)	(2,842)	1,962
Increase (decrease) in accounts payable and accrued expenses	6,619	18,330	22,101
Increase (decrease) in other liabilities	19,832	990	(4,934)
Net cash provided by (used in) operating activities	107,399	22,431	13,197
Cash flow from investing activities:			
Capital expenditures:			
Development of oil and natural gas properties	(52,712)	(859)	(21,988)
Purchases of other property and equipment	(12,767)	(2,299)	(12,808)
Acquisition of properties	(249,338)	—	—
Proceeds from sale of properties and equipment and other	234,292	25	194
Net cash (used in) provided by investing activities	(80,525)	(3,133)	(34,602)
Cash flow from financing activities:			
Proceeds from sale of Series A convertible preferred stock	—	335,000	—
Borrowings under new credit facility	402,285	—	—
Repayments on new credit facility	(23,285)	—	—
Repayments on previous credit facility	(451,000)	(497,668)	(1,701)
Borrowings under previous credit facility	51,000	—	—
Debt issuance costs	(22,170)	—	—
Net cash used in financing activities	(43,170)	(162,668)	(1,701)
Net decrease in cash and cash equivalents	(16,296)	(143,370)	(23,106)
Cash, cash equivalents and restricted cash:			
Beginning	85,034	228,404	251,510
Ending	$ 68,738	$ 85,034	$ 228,404

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

BERRY PETROLEUM COMPANY, LLC
(PREDECESSOR) CONSOLIDATED STATEMENTS OF EQUITY
(in thousands)

	Member's Capital	Accumulated (Deficit)	Total Member's equity
Balance, December 31, 2015	$ 2,798,713	$ (1,012,554)	$ 1,786,159
Net loss	—	(1,283,196)	(1,283,196)
Balance, December 31, 2016	2,798,713	(2,295,750)	502,963
Net loss	—	(502,964)	(502,964)
Other	1	—	1
	2,798,714	(2,798,714)	—
Cancellation of Predecessor Equity	(2,798,714)	2,798,714	—
Balance, February 28, 2017	$ —	$ —	$ —

BERRY PETROLEUM CORPORATION
(SUCCESSOR) CONSOLIDATED STATEMENTS OF EQUITY
(in thousands)

	Series A Convertible Preferred Stock		Common Stock				
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Accumulated (Deficit)	Total Stockholders' equity
Issuance of Series A convertible preferred stock	35,845	$ 335,000	—	$ —	$ —	$ —	$ 335,000
Issuance of Common Stock	—	—	32,920	33	543,494	—	543,527
Beneficial conversion feature related to Series A convertible preferred stock	—	—	—	—	27,751	(27,751)	—
Elimination of accumulated deficit	—	—	—	—	(27,751)	27,751	—
Balance, February 28, 2017	35,845	335,000	32,920	33	543,494	—	878,527
Net loss	—	—	—	—	—	(21,068)	(21,068)
Stock based compensation	—	—	—	—	1,851	—	1,851
Balance, December 31, 2017	35,845	$ 335,000	32,920	$ 33	$ 545,345	$ (21,068)	$ 859,310

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

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017

Note 1—Basis of Presentation and Significant Accounting Policies

"Berry Corp." refers to Berry Petroleum Corporation, a Delaware corporation which is the sole member of Berry Petroleum Company, LLC, as of February 28, 2017.

"Berry LLC" refers to Berry Petroleum Company, LLC, a Delaware limited liability company.

As the context may require, the "Company", "we", "our" or similar words refer to (i) Berry Corp. ("the Successor") and Berry LLC, its consolidated subsidiary, as of and after February 28, 2017, as a whole or (ii) either Berry Corp. or Berry LLC on an individual basis as of and after February 28, 2017. References to historical activities of the "Company" prior to February 28, 2017, refer to activities of Berry LLC ("the Predecessor").

"Linn Energy" refers to Linn Energy, LLC, a Delaware limited liability company of which Berry LLC was formerly a wholly-owned, indirect subsidiary.

Subsequent events have been evaluated through April 11, 2018, the date these financial statements were available to be issued. Any material subsequent events that occurred prior to such date have been properly recognized or disclosed in the financial statements and related footnotes.

Certain prior year amounts have been reclassified to conform to the 2017 presentation. On the balance sheet, we reclassified the current portion of the asset retirement obligation and current accrued interest out of other accrued liabilities and into accounts payable and accrued expenses. Current restricted cash has been separated from other current assets and presented separately.

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law on February 13, 2017. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC.

On December 16, 2013, an affiliate of Linn Energy, LinnCo, LLC ("LinnCo"), acquired all the outstanding common shares of Berry Petroleum Company, a Delaware corporation, and contributed Berry Petroleum Company to Linn Energy in exchange for Linn Energy units. In connection with its acquisition by Linn Energy, Berry Petroleum Company was converted from a Delaware corporation into a Delaware limited liability company and changed its name to "Berry Petroleum Company, LLC." Linn Acquisition Company, LLC, a direct subsidiary of Linn Energy, became Berry LLC's sole member.

As discussed further in Note 2, on May 11, 2016 (the "Petition Date"), the Linn entities and, consequently, Berry LLC (collectively, the "Debtors"), filed voluntary petitions ("Bankruptcy Petitions") for relief under Chapter 11 ("Chapter 11") of the U.S. Bankruptcy Code ("Bankruptcy Code") in the U.S. Bankruptcy Court for the Southern District of Texas ("Bankruptcy Court"). The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040 (collectively, the "Chapter 11 Proceedings"). During the pendency of the Chapter 11 Proceedings, the debtors in the Chapter 11 Proceedings (the "Debtors"), operated their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. The Company emerged from bankruptcy as a stand-alone company separate from Linn Energy effective February 28, 2017 (the "Effective Date").

Our properties are located in the United States ("U.S."), in California (in the San Joaquin and Ventura basins), Utah (in the Uinta basin), Colorado (in the Piceance basin) and east Texas.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Principles of Consolidation and Reporting

The consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("GAAP") and include the accounts of the Successor and its wholly owned subsidiary after February 28, 2017 and the accounts of the Predecessor prior to February 28, 2017. All significant intercompany transactions and balances have been eliminated upon consolidation. For oil and gas exploration and production joint ventures in which we have a direct working interest, we account for our proportionate share of assets, liabilities, revenue, expense and cash flows within the relevant lines of the financial statements.

Bankruptcy Accounting

The consolidated financial statements have been prepared as if the Company will continue as a going concern and reflect the application of GAAP. GAAP requires that the financial statements, for periods subsequent to filing of the Chapter 11 Proceeding, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, gains and losses that are realized or incurred in the bankruptcy proceedings are recorded in "reorganization items, net" on our consolidated statements of operations. In addition, prepetition unsecured and under-secured obligations that may be impacted by the bankruptcy reorganization process have been classified as "liabilities subject to compromise" on our balance sheet. These liabilities are reported at the amounts allowed as claims by the Bankruptcy Court, although they may be settled for less.

Upon emergence from bankruptcy on February 28, 2017, we adopted fresh-start accounting which resulted in Berry Corp. becoming the financial reporting entity. As a result of the application of fresh-start accounting and the effects of the implementation of the Plan, the financial statements on or after February 28, 2017 are not comparable to the financial statements prior to that date. See Note 3 for additional information.

Use of Estimates

The preparation of the accompanying consolidated financial statements in conformity with GAAP required management of the Company to make informed estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses.

As fair value is a market-based measurement, it was determined based on the assumptions that we believe market participants would use. Determination of these assumptions were based on management's best estimates and judgment. Management evaluates its assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such assumptions are adjusted when management determines that facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in these assumptions resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

The estimates that are particularly significant to the financial statements include estimates of our reserves of oil and gas, future cash flows from oil and gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. In addition, as part of fresh-start accounting, we made estimates and assumptions related to our reorganization value, liabilities subject to compromise and the fair value of assets and liabilities recorded.

Cash Equivalents

We consider all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Cash

At December 31, 2017, "restricted cash" of approximately $35 million was classified as a current asset on the consolidated balance sheet and represents cash that will be used to settle certain claims and pay certain professional fees in accordance with the Plan (as defined below). At December 31, 2016, "restricted cash" of approximately $198 million classified as a non-current asset on the balance sheet represented cash that Linn Energy contributed to Berry LLC in May 2015 to post with Berry LLC's lenders in connection with the reduction in the Pre-Emergence Credit Facility's borrowing base, as well as associated interest income. Such restricted cash was used in February 2017 to repay a portion of the borrowings outstanding under the Pre-emergence Credit Facility, which is reflected as a non-cash transaction.

Inventories

Inventories were included in other current assets. Oil and natural gas inventories were valued at the lower of cost or net realizable value. Materials and supplies were valued at their weighted-average cost and are reviewed periodically for obsolescence.

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At December 31, 2017 and December 31, 2016, net deferred financing fees of approximately $20 million and $6 million were included in "other noncurrent assets" and "other current assets", respectively, on the balance sheets. These deferred financing costs are being amortized over the life of the debt agreement.

For the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, amortization expense of approximately $2 million, $0 and $2 million was included in "interest expense" in the consolidated statements of operations.

Oil and Natural Gas Properties

Proved Properties

We account for oil and natural gas properties in accordance with the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively. Costs of retired, sold or abandoned properties that constitute a part of an amortization base 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 the current period. Gains or losses from the disposal of other properties are recognized in the current period. For assets acquired, we base the capitalized cost is based on fair value at the acquisition date. We expense expenditures for maintenance and repairs necessary to maintain properties in operating condition, as well as annual lease rentals, are expensed as they are incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized over the remaining lives of the related assets. We only capitalized this interest on borrowed funds related to our share of costs associated with qualifying capital expenditures. Interest is capitalized only during the periods in which these assets are brought to their intended use. The amount of capitalized interest and exploratory well costs in 2017 and 2016 was not significant.

We evaluate the impairment of our proved oil and natural gas properties generally on a field by field basis or at the lowest level for which cash flows are identifiable, whenever events or changes in circumstance indicate that the carrying value may not be recoverable. We reduce the carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value. We measure the fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a risk-adjusted discount rate. These inputs require significant judgments and estimates by our management at the time of the valuation and are the most sensitive estimates we make and the most likely to change. The underlying commodity prices are embedded in our estimated cash flows and are the product of a process that begins with the relevant forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors our management believes will impact realizable prices.

Impairment of Proved Properties

Based on the analysis described above, for the year ended December 31, 2016, we recorded noncash impairment charges of approximately $1.0 billion associated with proved oil and natural gas properties. The 2016 impairment charges were due to a decline in commodity prices, changes in expected capital development and a decline in our estimates of proved reserves. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges were included in “impairment of long-lived assets” on our statements of operations.

The 2016 non-cash impairment charges associated with proved oil and natural gas properties arose in the following operating areas of our Predecessor:

	(in thousands)
California operating area	$ 984,288
Uinta basin operating area	26,677
East Texas operating area	6,387
	$ 1,017,352

Unproved Properties

A portion of the carrying value of our oil and gas properties was attributable to unproved properties. At December 31, 2017 and 2016, the net capitalized costs attributable to unproved properties were approximately $517 million and $680 million, respectively. The unproved amounts were not subject to depreciation, depletion and amortization until they were classified as proved properties and amortized on a unit-of-production basis. We evaluate the impairment of our unproved oil and gas properties whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of such properties would be expensed. The timing of any write-downs of unproved properties, if warranted, depends upon management’s plans, the nature, timing and extent of future exploration and development activities and their results.

We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance at December 31, 2017. Based on the analysis described above, for the year ended December 31, 2016, we recorded noncash impairment charges of approximately $13 million associated with unproved oil and natural gas properties. The impairment charges in 2016 were primarily due to a decline in commodity prices and changes in expected capital development. The carrying values of the impaired unproved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in “impairment of long-lived assets” on our statements of operations.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, buildings, software, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These assets are recorded at cost and are depreciated using the straight-line method based on expected useful lives ranging from ten to 39 years for buildings and leasehold improvements and two to 30 years for plant and pipeline, drilling and other equipment.

Asset Retirement Obligation

We recognize the fair value of asset retirement obligations ("AROs") in the period in which a determination is made that a legal obligation exists to dismantle an asset and remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The liability amounts were based on future retirement cost estimates and incorporate many assumptions such as time to abandonment, technological changes, future inflation rates and the risk-adjusted discount rate. When the liability was initially recorded, we capitalized the cost by increasing the related property, plant and equipment ("PP&E") balances. If the estimated future cost of the AROs changes, we record an adjustment to both the ARO and PP&E. Over time, the liability is increased, and expense is recognized through accretion, and the capitalized cost is depreciated over the useful life of the asset.

In certain cases, we do not know or cannot estimate when we may settle these obligations and therefore we cannot reasonably estimate the fair value of the liabilities. We will recognize these AROs in the periods in which sufficient information becomes available to reasonably estimate their fair values.

The following table summarizes activity in our ARO account in which approximately $95 million, $109 million and $139 million were included in long term liabilities as of December 31, 2017, February 28, 2017 and December 31, 2016, respectively, with the remaining current portion included in accrued liabilities:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
		(in thousands)	
Beginning balance	$ 113,275	$ 141,798	$ 137,563
Liabilities incurred capitalized to properties	—	152	113
Liabilities settled and paid	(2,333)	(861)	(4,891)
Accretion expense	5,562	1,112	7,468
Disposition by sale	(19,082)	—	—
Revision of estimates	—	—	1,545
Fresh-Start adjustment	—	(28,926)	—
Ending balance	$ 97,422	$ 113,275	$ 141,798

Revenue Recognition

We recognize revenue from oil, natural gas and natural gas liquids ("NGL") production when title has passed from us to the purchaser, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. We recognize our share of revenues net of any royalties and other third-party share. In addition, we engage in the purchase, gathering and transportation of third-party natural gas and subsequently market such natural gas to independent purchasers under separate arrangements. As a result, we separately report third-party marketing revenues and marketing expenses.

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques: Level 1—using quoted prices in active markets for the assets or liabilities; Level 2—using observable inputs other than quoted prices for the assets or liabilities; and Level 3—using unobservable inputs. Transfers between levels, if any, are recognized at the end of each reporting period. We primarily apply the market approach for recurring fair value measurement, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows and discounts those cash flows using a risk-adjusted discount rate.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives. Commodity derivatives are carried at fair value. In addition to using market data in determining these fair values, we make assumptions about the risks inherent in the inputs to the valuation technique. Our commodity derivatives comprise over-the-counter ("OTC") bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including publicly available prices and forward curves generated from a compilation of data gathered from third parties. We validate the data provided by third parties by assessing the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. Substantially all of these inputs are observable data or are supported by observable prices at which transactions are executed in the marketplace. We classify these measurements as Level 2.

Our PP&E is written down to fair value if we determine that there has been an impairment in its value. The fair value is determined as of the date of the assessment using discounted cash flow models based on management's expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate.

Stock-based Compensation

Subsequent to February 28, 2017, we issued restricted stock units ("RSUs") that vest over time and performance-based restricted stock units ("PRSUs") that vest based on our achievement of certain average prices per share, to certain employees and non-employee directors. The fair value of the stock-based awards is determined at the date of grant and is not remeasured. We determined the fair value of the RSUs based on an estimate of the fair value of our equity using an income approach. We used a discounted cash flow method to value the estimated future cash flows at an appropriate discount rate. If and when the Company's underlying shares begin trading in the public markets, these estimates will no longer be necessary. For PRSUs, compensation value is measured on the grant date using payout values derived from a Monte-Carlo valuation model. Estimates used in the Monte Carlo valuation model are considered highly-complex and subjective. Compensation expense, net of actual forfeitures, for the RSUs and PRSUs is recognized on a straight-line basis over the requisite service periods, which is generally over the awards' respective three-year vesting or performance periods.

Other Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to loss in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management's judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management's plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Electricity Cost Allocation

We own five cogeneration facilities. Our investment in cogeneration facilities has been for the express purpose of lowering steam costs in our heavy oil operations in California and securing operating control of the respective steam generation. Cogeneration, also called combined heat and power, extracts energy from the exhaust of a turbine, which would otherwise be wasted, to produce steam. Such cogeneration operations also produce electricity. We allocate steam and electricity costs to lease operating expenses based on the conversion efficiency of the cogeneration facilities plus certain direct costs of producing steam. We also allocate a portion of the electricity production costs related to the power we sell to third parties, which is reported in "electricity generation expenses" in the statement of operations.

Income Taxes

Prior to the consummation of the Plan, as defined below, the Predecessor was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the company are passed through to its members. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, the Predecessor was not a taxable entity, it did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of the company.

On the Effective Date, upon consummation of the Plan, the Successor became a C Corporation subject to federal and state income taxes. The impact of changes in tax regulation are reflected when enacted. Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion, or all, of the deferred tax assets will not be realized. We recognize a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit).

Earnings per Share

We computed basic and diluted earnings per share (EPS) using the two-class method required for participating securities. Restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights at the same rate as common stock.

Under the two-class method, undistributed earnings allocated to participating securities are subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses. For basic EPS, the weighted-average number of common shares outstanding excludes outstanding shares related to unvested restricted stock awards. For diluted EPS, the basic shares outstanding are adjusted by adding potentially dilutive securities, unless their effect is anti-dilutive.

Business and Credit Concentrations

We maintain our cash in bank deposit accounts which, at times, may exceed federally insured amounts. We have not experienced any losses in such accounts. We believe we are not exposed to any significant credit risk on our cash.

We also sell oil and natural gas to various types of customers, including pipelines, refineries and other oil and natural gas companies and electricity to utility companies. Based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition, results of operations or net cash provided by operating activities.

For the ten months ended December 31, 2017, our three largest customers represented approximately 37%, 34% and 15% of our oil, gas and NGL sales. For the two months ended February 28, 2017, our two largest customers represented approximately 36% and 31% of our oil, gas and NGL sales. For the year ended December 31, 2016, our two largest customers represented approximately 34% and 28% of our oil, gas and NGL sales. For the years ended December 31, 2017 and December 31, 2016, 100% of electricity sales were attributable to two customers.

At December 31, 2017, trade accounts receivable from two customers represented approximately 35% and 26% of our receivables. At December 31, 2016, trade accounts receivable from two customers represented approximately 29% and 21% of our receivables.

Recently Issued Accounting Standards

In August 2017, the Financial Accounting Standards Board ("FASB") released targeted improvements to hedge accounting standards that will expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with a company's risk management activities. These rules are also intended to decrease the cost and complexity of hedge accounting. The new rules are effective for fiscal years beginning after December 15, 2018. We are currently evaluating the impact of the adoption of these new rules.

In May 2017, the FASB issued rules to simplify the guidance on the modification of share-based payment awards. The amendments provide clarity on which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting prospectively. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of these rules to have a significant impact on our consolidated financial statements.

In January 2017, the FASB issued rules that changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of these rules to have a significant impact on our consolidated financial statements.

In November 2016, the FASB issued rules intended to address the diversity in practice in classification and presentation of changes in restricted cash on the statement of cash flows. These rules will be applied retrospectively as of the date of adoption and are effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years (with early adoption permitted). The adoption of these rules is expected to result in the inclusion of restricted cash in the beginning and ending balances of cash on the statements of cash flows and require additional disclosures.

In August 2016, the FASB issued rules that modify how certain cash receipts and cash payments are presented and classified in the statement of cash flows. These rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with earlier adoption permitted. We do not expect adoption of these rules to have a significant impact on our consolidated financial statements.

In June 2016, the FASB issued rules that change how entities will measure credit losses for certain financial assets and other instruments that are not measured at fair value. These rules are effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact of these rules on our consolidated financial statements.

In February 2016, the FASB issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. These rules will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with earlier application permitted. We are currently evaluating the impact of these rules on our consolidated financial statements.

During 2016, the FASB issued rules clarifying the new revenue recognition standard issued in 2014. The new rules are intended to improve and converge the financial reporting requirements for revenue from contracts with customers. For non-public companies, these rules are effective for fiscal years beginning after December 15, 2018, including interim periods within those years. We are currently evaluating the impact of the adoption of these rules on our consolidated financial statements and related disclosures.

Note 2—Emergence from Voluntary Reorganization under Chapter 11

On the Petition Date, the Debtors filed Bankruptcy Petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040.

In December 2016, Berry LLC and Linn Acquisition Company, LLC, on the one hand, and Linn Energy and its other affiliated debtors, on the other hand, filed separate plans of reorganization with the Bankruptcy Court. The "Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry Petroleum Company, LLC" (the "Plan") was filed on December 13, 2016. On January 27, 2017, the Bankruptcy Court entered its confirmation order (the "Confirmation Order") approving and confirming the Plan.

On February 28, 2017, the Plan became effective and was implemented in accordance with its terms. Among other transactions, Linn Acquisition Company, LLC transferred 100% of Berry LLC's outstanding membership interests to Berry Corp. As a result, Berry LLC emerged from bankruptcy as a wholly-owned subsidiary of Berry Corp., separate from Linn Energy and its affiliates.

Plan of Reorganization

On the Effective Date, the Company consummated the following reorganization transactions in accordance with the Plan:

- Linn Acquisition Company, LLC transferred 100% of the outstanding membership interests in Berry LLC to Berry Corp. pursuant to an assignment agreement, dated February 28, 2017 between Linn Acquisition Company, LLC and Berry Corp. (the "Assignment Agreement"). Under the Assignment Agreement, Berry LLC became a wholly-owned operating subsidiary of Berry Corp.

- The holders of claims under the Company's Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry LLC, as borrower, Wells Fargo Bank, N.A., as administrative agent, and certain lenders, (as amended, the "Pre-Emergence Credit Facility"), received (i) their pro rata share of a cash paydown and (ii) pro rata participation in the new facility (the "Emergence Credit Facility"). As a result, all outstanding obligations under the Pre-Emergence Credit Facility were canceled and the agreements governing these obligations were terminated.

- Berry LLC, as borrower, entered into the Emergence Credit Facility with the holders of claims under the Pre-Emergence Credit Facility, as lenders, and Wells Fargo Bank, N.A, as administrative agent, providing for a new reserve-based revolving loan with up to $550 million in borrowing commitments. For additional information about the Emergence Credit Facility, see Note 5.

- The holders of Berry LLC's 6.75% senior notes due 2020, issued by Berry LLC pursuant to a Second Supplemental Indenture, dated November 1, 2010, and 6.375% senior notes due 2022, issued by Berry LLC pursuant to a Third Supplemental Indenture, dated March 9, 2012 (collectively, the "Unsecured Notes"), received a right to their pro rata share of either (i) 32,920,000 shares of common stock in Berry Corp. or, for those non-accredited investors holding the Unsecured Notes that irrevocably elected to receive a cash recovery, cash distributions from a $35 million cash distribution pool (the "Cash Distribution Pool") and (ii) specified rights to participate in a two-tranche offering of rights to purchase Series A Preferred Stock at an aggregate purchase price of $335 million (as further defined in the Plan, the "Berry Rights Offerings"). As a result, all outstanding obligations under the Unsecured Notes were canceled and the indentures and related agreements governing these obligations were terminated.

- The holders of unsecured claims against Berry LLC, (other than the Unsecured Notes) (the "Unsecured Claims") received a right to their pro rata share of either (i) 7,080,000 shares of common stock in Berry Corp. or (ii) in the event that such holder irrevocably elected to receive a cash recovery, cash distributions from the Cash Distribution Pool. As a result, all outstanding obligations under the Unsecured Notes and the indentures governing such obligations were canceled and the obligations arising from the Unsecured Claims were extinguished.

- Berry LLC settled all intercompany claims against Linn Energy and its affiliates pursuant to a settlement agreement approved as part of the Plan and the Confirmation Order. The settlement agreement provided Berry LLC with a $25 million general unsecured claim against Linn Energy which Berry LLC has fully-reserved.

Bank RSA

Prior to the Petition Date, on May 10, 2016, the Debtors entered into a restructuring support agreement ("Bank RSA") with certain holders ("Consenting Bank Creditors") collectively holding or controlling at least 66.67% by aggregate outstanding principal amounts under (i) the Pre-Emergence Credit Facility and (ii) Linn Energy's Sixth Amended and Restated Credit Agreement ("Linn Credit Facility"). The Bank RSA set forth, subject to certain conditions, the commitment of the Consenting Bank Creditors to support a comprehensive restructuring of the Debtors' long-term debt. The Bank RSA provided that the Consenting Bank Creditors would support the use of Berry LLC's cash collateral under specified terms and conditions, including adequate protection terms. The Bank RSA required the Debtors and the Consenting Bank Creditors to, among other things, support and not interfere with consummation of the restructuring transactions contemplated by the Bank RSA and, as to the Consenting Bank Creditors, vote their claims in favor of the Plan.

Liabilities Subject to Compromise

Berry LLC's balance sheet as of December 31, 2016, included amounts classified as "liabilities subject to compromise," which represented prepetition liabilities that were allowed, or that the Company estimated would be allowed, as claims in its Chapter 11 case. The following table summarizes the components of liabilities subject to compromise included on the balance sheet:

	Berry LLC (Predecessor) December 31, 2016 (in thousands)
Accounts payable and accrued expenses	$ 151,515
Accrued interest payable	15,238
Debt	833,800
Liabilities subject to compromise	$ 1,000,553

Through the claims resolution process, many claims were disallowed by the Bankruptcy Court because they were duplicative, amended or superseded by later filed claims, were without merit, or were otherwise overstated. Throughout the Chapter 11 proceedings, the Debtors also resolved many claims through settlements or by Bankruptcy Court orders following the filing of an objection. The Debtors will continue to settle claims and file additional objections with the Bankruptcy Court. To the extent that such adjustments relate to Unsecured Claims, no additional liability to the Company is anticipated as such claimants received only a right to their pro rata share of either (i) 7,080,000 shares of common stock in Berry Corp. or (ii) in the event that such holder irrevocably elected to receive a cash recovery, cash distributions from the Cash Distribution Pool. The liability for this cash distribution pool was $34.8 million at December 31, 2017 and is included in liabilities subject to compromise. In light of the substantial number and amounts of claims filed, we expect the claims resolution process and the ultimate number and amount of, or exact recovery with respect to, allowed Unsecured claims, will take considerable time to complete.

Reorganization Items, Net

We have incurred and continue to incur expenses associated with the reorganization. Reorganization items, net represents costs and income directly associated with the Chapter 11 proceedings since the Petition Date, and also includes adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined. The following table summarizes the components of reorganization items included in the consolidated statements of operations:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
		(in thousands)	
Gain on settlement of liabilities subject to compromise	$ —	$ 421,774	$ —
Unamortized premiums	—	—	10,923
Terminated contracts	—	—	(55,148)
Fresh-start valuation adjustments	—	(920,699)	—
Legal and other professional advisory fees	(1,732)	(19,481)	(30,130)
Other	—	10,686	1,693
Reorganization items, net	$ (1,732)	$ (507,720)	$ (72,662)

Effect of Filing on Creditors

Subject to certain exceptions, under the Bankruptcy Code, the filing of Bankruptcy Petitions automatically enjoined, or stayed, the continuation of most judicial or administrative proceedings or filing of other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the Petition Date. Absent an order of the Bankruptcy Court, substantially all of the Debtors' prepetition liabilities were subject to settlement under the Bankruptcy Code. Although the filing of Bankruptcy Petitions triggered defaults on the Debtors' debt obligations, creditors were stayed from taking any actions against the Debtors as a result of such defaults, subject to certain limited exceptions permitted by the Bankruptcy Code. The Predecessor did not record interest expense on its senior notes for the period from May 12, 2016 through December 31, 2016 and from January 1, 2017 through February 28, 2017. For those periods, unrecorded contractual interest was approximately $35 million and $9 million, respectively.

Covenant Violations

The Predecessor's filing of the Bankruptcy Petitions constituted an event of default that accelerated the Predecessor's obligations under its Pre-Emergence Credit Facility and its senior notes. Additionally, other events of default, including cross-defaults, occurred, including the failure to make interest payments on the Predecessor's senior notes. Under the Bankruptcy Code, the creditors under these debt agreements were stayed from taking any action against the Predecessor as a result of any default. See Note 5 for additional details about the Predecessor's debt.

Prior Credit Facility

The Pre-Emergence Credit Facility contained a requirement to deliver audited financial statements without a going concern or like qualification or exception. Consequently, the filing of the Predecessor's 2015 Annual Report on Form 10-K which included a going concern explanatory paragraph resulted in a default under the Pre-Emergence Credit Facility as of the filing date, March 28, 2016, subject to a 30-day grace period.

On April 12, 2016, the Predecessor entered into an amendment to the Pre-Emergence Credit Facility. The amendment provided for, among other things, an agreement that (i) certain events would not become defaults or events of default until May 11, 2016, (ii) the borrowing base would remain constant until May 11, 2016, unless reduced as a result of swap agreement terminations or collateral sales, (iii) the Predecessor would have access to $45 million in cash that was previously restricted in order to fund ordinary course operations and (iv) the Predecessor, the administrative agent and the lenders would negotiate in good faith the terms of a restructuring support agreement in furtherance of a restructuring of the capital structure of the Predecessor. As a condition to closing the amendment, the Predecessor provided control agreements over certain deposit accounts.

The filing of the Bankruptcy Petitions constituted an event of default that accelerated the Predecessor's obligations under the Pre-Emergence Credit Facility. However, under the Bankruptcy Code, the creditors under this debt agreement were stayed from taking any action against the Predecessor as a result of the default.

Senior Notes

The Predecessor deferred making an interest payment totaling approximately $18 million due March 15, 2016, on the Predecessor's 6.375% senior notes due September 2022, which resulted in the Predecessor being in default under these senior notes. The indenture governing the notes provided the Predecessor a 30-day grace period to make the interest payment.

On April 14, 2016, within the 30-day interest payment grace period provided for in the indenture governing the notes, the Predecessor made an interest payment of approximately $18 million in satisfaction of its obligations.

The Predecessor failed to make interest payments due on its senior notes subsequent to April 14, 2016.

The filing of the Bankruptcy Petitions constituted an event of default that accelerated the Predecessor's obligations under the indentures governing the senior notes. However, under the Bankruptcy Code, holders of the senior notes were stayed from taking any action against the Predecessor as a result of the default.

Note 3—Fresh-Start Accounting

Upon our emergence from bankruptcy, we were required to adopt fresh-start accounting, which, with the recapitalization described above, resulted in Berry Corp. being treated as the new entity for financial reporting purposes. We were required to adopt fresh-start accounting upon our emergence from bankruptcy because (i) the holders of existing voting ownership interests of our predecessor company received less than 50% of the voting shares of Berry Corp. and (ii) the reorganization value of our assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims. An entity applying fresh-start accounting upon emergence from bankruptcy is viewed as a new reporting entity from an accounting perspective, and accordingly, may select new accounting policies.

The reorganization value of our assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims, as shown below:

	(in thousands)
Liabilities subject to compromise	$ 1,000,336
Pre-petition debt not classified as subject to compromise	891,259
Post-petition liabilities	245,702
Total post-petition liabilities and allowed claims	2,137,297
Reorganization value of assets immediately prior to implementation of the Plan	(1,722,585)
Excess post-petition liabilities and allowed claims	$ 414,712

Upon adoption of fresh-start accounting, the reorganization value derived from the enterprise value was allocated to our assets and liabilities based on their fair values in accordance with GAAP. The Effective Date fair values of our assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet. The effects of the Plan and the application of fresh-start accounting were reflected in the financial statements as of February 28, 2017, and the related adjustments thereto were recorded on the statement of operations for the two months ended February 28, 2017.

As a result of the adoption of fresh-start accounting and the effects of the implementation of the Plan, our consolidated financial statements subsequent to February 28, 2017, are not comparable to our financial statements prior to February 28, 2017.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our consolidated financial statements and related footnotes are presented with a black line division, which delineates the lack of comparability between amounts presented after February 28, 2017, and amounts presented on or prior to February 28, 2017. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

Reorganization Value

Under GAAP, a value was assigned to the equity of the emerging entity as of the date of adoption of fresh-start accounting. The Plan and disclosure statement approved by the Bankruptcy Court did not include an enterprise value or reorganization value, nor did the Bankruptcy Court approve a value as part of its confirmation of our Plan. Our reorganization value was derived from an estimate of enterprise value, or the fair value of our long-term debt, stockholders' equity and working capital. Reorganization value approximates the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Based on the various estimates and assumptions necessary for fresh-start accounting, our enterprise value as of the Effective Date was estimated to be approximately $1.3 billion. The enterprise value was estimated using a sum of parts approach. The sum of parts approach represents the summation of the indicated fair value of the component assets of the Company. The fair value of our assets was estimated by relying on a combination of the income, market and cost approaches.

The estimated enterprise value, reorganization value and equity value are highly dependent on the achievement of the financial results contemplated in our underlying projections. While we believe the assumptions and estimates used to develop enterprise value and reorganization value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. Additionally, the assumptions used in estimating these values are inherently uncertain and require judgment. The primary assumptions for which there is a reasonable possibility of the occurrence of a variation that would have significantly affected the reorganization value include those regarding pricing, discount rates and the amount and timing of capital expenditures.

Our principal assets are our oil and natural gas properties. The fair values of oil and natural gas properties were estimated using a valuation technique consistent with the income approach; specifically, the discounted cash flows method. We also used the market approach to corroborate the valuation results from the income approach. We used a market-based weighted average cost of capital discount rate of 10% for proved and unproved reserves, with further risk adjustment factors applied to the discounted values. The underlying commodity prices embedded in our estimated cash flows were based on the New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that we believe will impact realizable prices. NYMEX forward curve pricing was used for years 2017 through 2019 and then was escalated at approximately 2.0%.

See below under "Fresh-Start Adjustments" for additional information regarding assumptions used in the valuation of our various other significant assets and liabilities.

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date:

	(in thousands)
Enterprise value	$ 1,278,527
Plus: Fair value of non-debt liabilities	282,511
Reorganization value of the Successor's assets	$ 1,561,038

The fair value of non-debt liabilities consists of liabilities assumed by the Successor on the Effective Date and excludes the fair value of long-term debt.

Consolidated Balance Sheet

The adjustments included in the following fresh-start consolidated balance sheet reflect the effects of the transactions contemplated by the Plan and executed on the Effective Date (reflected in the column "Reorganization Adjustments") as well as fair value and other required accounting adjustments resulting from the adoption of fresh-start accounting (reflected in the column "Fresh-Start Adjustments"). The explanatory notes provide additional information with regard to the adjustments recorded, methods used to determine the fair values and significant assumptions.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	As of February 28, 2017			
	Berry LLC (Predecessor)	Reorganization Adjustments(1)	Fresh-Start Adjustments	Berry Corp. (Successor)
	(in thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 27,407	$ 4,642 (2)	$ —	$ 32,049
Accounts receivable	76,027	(15,700) (3)	(816) (14)	59,511
Derivative instruments	243	—	—	243
Restricted cash	128	52,732 (4)	—	52,860
Other current assets	18,437	(5,558) (5)	3,873 (15)	16,752
Total current assets	122,242	36,116	3,057	161,415
Noncurrent assets:				
Oil and natural gas properties	5,031,498	—	(3,787,898) (16)	1,243,600
Less accumulated depletion and amortization	(2,814,999)	—	2,814,999 (16)	—
	2,216,499	—	(972,899)	1,243,600
Other property and equipment	124,379	—	(15,576) (17)	108,803
Less accumulated depreciation	(22,107)	—	22,107 (17)	—
	102,273	—	6,530	108,803
Derivative instruments	57	—	—	57
Restricted cash	197,939	(197,814) (2)	—	125
Other noncurrent assets	16,076	151 (6)	30,811 (18)	47,038
Total assets	$ 2,655,086	$ (161,547)	$ (932,501)	$ 1,561,038
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 60,323	$ 52,371 (7)	$ 3,818 (19)	$ 116,512
Derivative instruments	5,355	—	—	5,355
Current portion of long-term debt, net	891,259	(891,259) (8)	—	—
Other accrued liabilities	7,335	(3,760) (9)	1,295 (20)	4,870
Total current liabilities	964,272	(842,648)	5,113	126,737
Derivative instruments	1,710	—	—	1,710
Long-term debt	—	400,000 (10)	—	400,000
Other noncurrent liabilities	170,979	—	(16,915) (21)	154,064
Liabilities subject to compromise	1,000,336	(1,000,336) (11)	—	—
Equity:				
Predecessor additional paid-in capital	2,798,714	(2,798,714) (12)	—	—
Predecessor accumulated deficit	(2,280,925)	375,159 (13)	1,905,766 (22)	—
Successor preferred stock	—	335,000 (12)	—	335,000
Successor common stock	—	33 (12)	—	33
Successor additional paid-in capital	—	3,369,959 (12)	(2,826,465) (22)	543,494
Total equity	517,789	1,281,437	(920,699)	878,527
Total liabilities and equity	$ 2,655,086	$ (161,547)	$ (932,501)	$ 1,561,038

Reorganization Adjustments:
(1) Represent amounts recorded as of the Effective Date for the implementation of the Plan, including, among other items, settlement of the Predecessor's liabilities subject to compromise, repayment of certain of the Predecessor's debt, cancellation of the Predecessor's equity, issuances of the Successor's common stock and preferred stock, proceeds received from the Berry Rights Offerings and issuance of the Successor's debt.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Changes in cash and cash equivalents included the following:

		(all $ in thousands)
Borrowings under the Emergence Credit Facility	$	400,000
Proceeds from issuance of preferred stock pursuant the Berry Rights Offerings		335,000
Cash receipt from Linn Energy, LLC for ad valorem taxes		23,366
Removal of restriction on cash balance (includes $128 previously recorded as short term)		197,942
Payment to the holders of claims under the Pre-Emergence Credit Facility (including $29 in bank fees and $3,760 in interest)		(897,663)
Payment of professional fees		(992)
Payment of Emergence Credit Facility fee that was capitalized		(151)
Funding of the general unsecured claims Cash Distribution Pool		(35,000)
Funding of the professional fees escrow account		(17,860)
Changes in cash and cash equivalents	$	4,642

(3) Collection of overpayment to Linn Energy, LLC for ad valorem taxes.
(4) Primarily reflects the transfer to restricted cash to fund the Predecessor’s professional fees escrow account and general unsecured claims Cash Distribution Pool.
(5) Primarily reflects the write-off of the Predecessor’s deferred financing fees.
(6) Reflects the capitalization of deferred financing fees related to the Emergence Credit Facility.
(7) Net increase in accounts payable and accrued expenses reflects:

		(all $ in thousands)
Recognition of payables for the general unsecured claims Cash Distribution Pool	$	35,000
Recognition of payables for the professional fees escrow account		17,860
Recognition of payable for ad valorem tax liability		7,666
Net change of other professional fees payable		(8,161)
Other		6
Net increase in accounts payable and accrued expenses	$	52,371

(8) Reflects the repayment of the Pre-Emergence Credit Facility.
(9) Reflects the payment of accrued interest on the Pre-Emergence Credit Facility.
(10) Reflects borrowings under the Emergence Credit Facility.
(11) Settlement of liabilities subject to compromise and the resulting net gain were determined as follows:

		(all $ in thousands)
Accounts payable and accrued expenses	$	151,298
Accrued interest payable		15,238
Debt		833,800
Total liabilities subject to compromise		1,000,336
Funding of the general unsecured claims Cash Distribution Pool		(35,000)
Common stock to holders of Unsecured Notes and general unsecured creditors		(543,562)
Gain on settlement of liabilities subject to compromise	$	421,774

(12) Net increase in capital accounts reflects:

		(all $ in thousands)
Common stock to holders of Unsecured Notes and general unsecured creditors	$	543,562
Payment of issuance costs		(35)
Dividend related to beneficial conversion feature of preferred stock		27,751
Cancellation of the Predecessor’s additional paid-in capital		2,798,714
Par value of common stock		(33)
Change in additional paid-in capital		3,369,959
Proceeds from issuance of preferred stock		335,000
Par value of common stock		33
Predecessor’s additional paid-in capital		(2,798,714)
Net increase in capital accounts	$	906,278

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

See Note 8 for additional information on the issuances and distributions of the Successor's common and preferred stock.
(13) Net decrease in accumulated deficit reflects:

		(all $ in thousands)
Recognition of gain on settlement of liabilities subject to compromise	$	421,774
Recognition of professional fees		(13,667)
Write-off of deferred financing fees		(5,197)
Total reorganization items, net		402,910
Dividend related to beneficial conversion feature of preferred stock		(27,751)
Net decrease in accumulated deficit	$	375,159

Fresh-Start Adjustments:
(14) Reflects a change in accounting policy from the entitlements method to the sales method for natural gas production imbalances.
(15) Primarily reflects an increase in the current portion of greenhouse gas allowances.
(16) Reflects a decrease of oil and natural gas properties, based on the methodology discussed in Note 4, and the elimination of accumulated depletion and amortization. The following table summarizes the components of oil and natural gas properties as of the Effective Date:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Fair Value		Historical Book Value	
	(in thousands)			
Proved properties	$	712,400	$	4,266,843
Unproved properties		531,200		764,655
		1,243,600		5,031,498
Less accumulated depletion and amortization		—		(2,814,999)
	$	1,243,600	$	2,216,499

(17) Reflects a decrease of other property and equipment and the elimination of accumulated depreciation. The following table summarizes the components of other property and equipment as of the Effective Date:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Fair Value		Historical Book Value	
	(in thousands)			
Natural gas plants and pipelines	$	91,427	$	109,675
Land		8,262		201
Furniture and office equipment		5,040		3,879
Buildings and leasehold improvements		2,740		5,884
Vehicles		1,156		4,542
Drilling and other equipment		178		198
		108,803		124,379
Less accumulated depreciation		—		(22,107)
	$	108,803	$	102,273

In estimating the fair value of other property and equipment, we used a combination of cost and market approaches. A cost approach was used to value our natural gas plants and pipelines, buildings, and furniture and office equipment based on current replacement costs of the assets less depreciation based on the estimated economic useful lives of the assets and age of the assets. A market approach was used to value our vehicles, drilling and other equipment, and land, using recent transactions of similar assets to determine the fair value from a market participant perspective.
(18) Primarily reflects an increase in greenhouse gas allowances of approximately $30 million and a joint venture investment of approximately $1 million. Greenhouse gas allowances were valued using a market approach based on trading prices for carbon credits on February 28, 2017. Our joint venture investment was valued based on a market approach using a market EBITDA multiple.
(19) Reflects increases for greenhouse gas emissions liabilities of approximately $4 million and a change in accounting policy from the entitlements method to the sales method for gas production imbalances of approximately $200,000, partially offset by a decrease for the current portion of intangibles liabilities of approximately $500,000.
(20) Reflects an increase of the current portion of asset retirement obligations.
(21) Primarily reflects a decrease for asset retirement obligations of approximately $30 million and for intangible liabilities of approximately$6 million, partially offset by an increase for greenhouse gas emissions liabilities of approximately $19 million. The fair value of asset retirement

obligations was estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plugging and abandonment costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. The intangible liabilities identified on the Effective Date were valued based on a combination of market and incomes approaches and will be amortized over the remaining life of the respective contract. Greenhouse gas emissions liabilities were valued using a market approach based on trading prices for greenhouse gas allowances on February 28, 2017.

(22) Reflects the cumulative impact of the fresh-start accounting adjustments discussed above and the elimination of the Predecessor's accumulated deficit.

Note 4—Oil and Natural Gas Properties and Other Property and Equipment

Oil and Natural Gas Capitalized Costs

As a result of the application of fresh-start accounting, we recorded our oil and natural gas properties and other property and equipment at fair value as of the Effective Date. The fair values of oil and natural gas properties were measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved and unproved properties include estimates of i) reserves ii) future operating and development costs iii) future commodity prices and (iv) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates at the time of the valuation and are the most sensitive and subject to change of our inputs. The fair value was estimated using inputs characteristic of a Level 3 fair value measurement.

Aggregate capitalized costs related to oil, natural gas and NGL production activities with applicable accumulated depletion and amortization are presented below:

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	December 31, 2017	December 31, 2016
	(in thousands)	
Proved properties	$ 825,416	$ 4,262,155
Unproved properties	517,037	764,655
	1,342,453	5,026,810
Less accumulated depletion and amortization	(54,785)	(2,789,368)
	$ 1,287,668	$ 2,237,442

Other Property and Equipment

Other property and equipment consisted of the following:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	December 31, 2017		December 31, 2016	
	(in thousands)			
Natural gas plants and pipelines	$	79,856	$	108,697
Buildings and leasehold improvements		2,986		5,884
Vehicles		3,228		4,600
Furniture and equipment		10,547		4,078
Land		8,262		201
		104,879		123,460
Less: accumulated depreciation		(5,356)		(20,759)
	$	99,523	$	102,701

Note 5—Debt

The following table summarizes our outstanding debt:

	Berry Corp. (Successor) December 31, 2017		Berry LLC (Predecessor) December 31, 2016	
	(in thousands)			
Current portion of debt:				
Pre-Emergence Credit Facility[(1)(2)]	$	—	$	891,259
Long-term debt:				
RBL Facility[(2)]	$	379,000	$	—
Liabilities subject to compromise:				
6.75% senior notes due November 2020[(3)]	$	—	$	261,100
6.375% senior notes due September 2022[(3)]	$	—	$	572,700

(1) Due to covenant violations, the Pre-Emergence Credit Facility was classified as current at December 31, 2016
(2) Variable interest rates of 4.8% and 5.5% at December 31, 2017 and December 31, 2016, respectively.
(3) The Company's senior notes were classified as liabilities subject to compromise at December 31, 2016.

Fair Value

Our debt was recorded at the carrying amount on the balance sheets. The carrying amounts of the Pre-Emergence Credit Facility and the RBL Facility (as defined below) approximated fair value because their interest rates were variable and reflective of market rates. The Predecessor's senior notes had a carrying value and fair value of $833.8 million and $522.2 million, respectively, at December 31, 2016. We used a market approach to determine the fair value of the Predecessor's senior notes using estimates based on prices quoted from third-party financial institutions, which is a Level 2 fair value measurement.

Credit Facilities

2016 and 2017 Credit Facilities

The Pre-Emergence Credit Facility dated November 15, 2010 and amended April 12, 2016, by and among the Predecessor as borrower, Wells Fargo Bank, N.A. as administrative agent and certain lenders provided for a senior revolving credit facility subject to the then-effective borrowing base. At December 31, 2016, the Predecessor had approximately $898 million in total borrowings (including outstanding letters of credit) under this credit facility and there was no remaining availability. The filing of the bankruptcy petitions constituted an event of default that accelerated the Predecessor's obligations under this facility. All outstanding obligations under the Pre-Emergence Credit Facility were canceled and the agreements governing these obligations were terminated on the Effective Date. See Note 2 for additional details on the Pre-Emergence Credit Facility.

Also on the Effective Date, we entered into a credit agreement ("the Emergence Credit Facility") with Wells Fargo Bank, N.A. as administrative agent and certain lenders. The Emergence Credit Facility provided for a revolving loan with up to $550 million in borrowing commitments, subject to a reserve borrowing base. The initial borrowing base was $550 million with a maturity date of February 27, 2022. Approximately $400 million in borrowings and $6 million in undrawn letters of credit were outstanding under the Emergence Credit Facility as of the Effective Date. The outstanding borrowings under the Emergence Credit Agreement bore interest at a rate equal to either (i) LIBOR plus an applicable margin ranging from 3.25% to 4.25% per annum, depending on levels of borrowing base usage and (ii) a customary base rate plus an applicable margin ranging from 2.25% to 3.25% per annum, depending on levels of borrowing base usage.

We executed amended and restated mortgages in order to achieve collateral coverage of no less than 95% of the total value of the proved reserves of our oil and natural gas properties.

On July 31, 2017, we entered into a new credit agreement ("RBL Facility"), also with Wells Fargo Bank, N.A. as administrative agent and certain lenders with up to $1.5 billion of commitments, subject to a reserve borrowing base, and an initial borrowing commitment of $500 million. The RBL Facility also provides a letter of credit sub-facility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. This facility matures on June 29, 2022. The RBL Facility was used to paydown the outstanding borrowings from the Emergence Credit Facility. All outstanding obligations under the Emergence Credit Facility were canceled and the agreements governing the obligations were terminated on July 31, 2017.

In connection with the issuance of the 2026 Notes (as defined below), the RBL Facility borrowing base was set at $400 million which incorporated a $100 million reduction, or 25% of the face value of the 2026 Notes (as defined below). In March 2018, we completed a borrowing base redetermination which reaffirmed our borrowing base at $400 million with an elected commitment feature that allows us to increase the RBL Facility to $575 million with lender approval. Borrowing base redeterminations become effective on, or about, each May 1 and November 1, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations.

The outstanding borrowings under the RBL Facility bear interest at a rate equal to either (i) a customary London interbank offered rate plus an applicable margin ranging from 2.50% to 3.5% per annum, and (ii) a customary base rate plus an applicable margin ranging from 1.5% to 2.5% per annum, in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.50% on the average daily unused amount of the borrowing availability under the RBL Facility. We have the right to prepay any borrowings under the RBL Facility with prior notice at any time without a prepayment penalty, other than customary "breakage" costs with respect to euro-dollar loans.

Berry Corp. guarantees and each future subsidiary of Berry Corp. (other than Berry LLC), with certain exceptions, is required to guarantee, our obligations and obligations of the other guarantors under the RBL Facility and under certain hedging transactions and banking services arrangements (the "Guaranteed Obligations"). In addition, pursuant to a Guaranty Agreement dated as of July 31, 2017, (the "Guaranty Agreement"), Berry LLC guarantees the Guaranteed

Obligations. The lenders under the RBL Facility hold a mortgage on 85% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions. The RBL Facility, with certain exceptions, also requires that any future subsidiaries of Berry LLC will also have to grant mortgages, security interests and equity pledges.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral.

As of December 31, 2017, the financial performance covenants under our RBL Facility were (i) a leverage ratio of no more than 4.0 to 1.0 and (ii) a current ratio of at least 1.0 to 1.0. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt.

As of December 31, 2017, we had approximately $100 million of available borrowing capacity under the RBL Facility.

As a condition of closing our RBL Facility, we were required to have in place the following commodity hedging coverage over our projected crude oil production from PDP reserves, on an annual basis:

	2018	2019
Oil Swaps required by RBL Facility		
Thousands of barrels (MBbls) per year	1,876	1,622
Minimum price	$ 44.87	$ 45.94

At December 31, 2017, we were in compliance with all financial debt covenants.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

As of December 31, 2017 and December 31, 2016, we had letters of credit outstanding of approximately $21 million and $6 million, respectively, under our revolving credit facilities. These letters of credit were issued to support ordinary course of business marketing, insurance, regulatory and other matters.

Predecessor’s Unsecured Notes

On the Effective Date, pursuant to the terms of the Plan, all outstanding obligations under the Predecessor’s Unsecured Notes were canceled and the indentures and related agreements governing these obligations were terminated. See Note 2 for additional information.

Senior Unsecured Notes Offering

In February 2018, we completed a private offering of $400 million, in aggregate, principal amount of 7.000% senior unsecured notes due 2026 (the “2026 Notes”), which resulted in net proceeds to us of approximately $392 million after deducting expenses and the initial purchasers’ discount. We used the net proceeds from the issuance of the 2026 Notes to repay borrowings under the RBL Facility and will use the remainder for general corporate purposes.

We may, at our option, redeem all or a portion of the 2026 Notes at any time on or after February 15, 2021. We are also entitled to redeem up to 35.0% of the aggregate principal amount of the 2026 Notes before February 15, 2021, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.0% of the principal amount of the 2026 Notes being redeemed, plus accrued and unpaid interest, if any. In addition, prior to February 15, 2021, we may redeem some or all of the 2026 Notes at a price equal to 100.0% of the principal amount thereof, plus a “make-whole” premium, plus any accrued and unpaid interest. If we experience certain kinds of changes of control, holders of the 2026 Notes may have the right to require us to repurchase their notes at 101.0% of the principal amount of the 2026 Notes, plus accrued and unpaid interest, if any.

The 2026 Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. The notes are fully and unconditionally guaranteed on a senior unsecured basis by us and will also be guaranteed by certain of our future subsidiaries (other than Berry LLC). The 2026 Notes and related guarantees are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our RBL Facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the 2026 Notes.

The indenture governing the 2026 Notes contains restrictive covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness
- transfer or sell assets;
- make investments;
- create certain liens securing indebtedness;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets; and
- engage in transactions with affiliates.

The indenture governing the 2026 Notes contains customary events of default, including, among others, (a) non-payment; (b) non-compliance with covenants (in some cases, subject to grace periods); (c) payment default under, or acceleration events affecting, material indebtedness and (d) bankruptcy or insolvency events involving us or certain of our subsidiaries.

Note 6—Derivatives

We have hedged a portion of our forecasted production to reduce exposure to fluctuations in oil and natural gas prices and to assist us in complying with covenants in our RBL Facility in the event of price deterioration. We have also hedged our exposure to differentials in certain operating areas but do not currently hedge exposure to natural gas differentials. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations that we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

Our current hedge positions consist of primarily oil swap contracts, though in the past we have also used collars and three-way collars and hedged our exposure to natural gas and natural gas liquids (NGL) price changes.

We enter into these transactions with respect to a portion of our projected production to provide an economic hedge of the risk related to the future commodity prices received. We do not enter into derivative contracts for speculative trading purposes. We did not designate any of our contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We account for our commodity derivatives at fair value on a recurring basis. We determine the fair value of these derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. See Note 1 for further information on our fair value measurement process.

As part of our hedging program, we entered into a number of derivative transactions that resulted in the following WTI-based crude oil contracts as of December 31, 2017:

	Q1 2018	Q2 2018	Q3 2018	Q4 2018	FY 2019	FY 2020
Sold Oil Calls:						
Hedged volume (MBbls)	225	225	225	225	840	390
Weighted average price ($/Bbl)	$ 55.00	$ 55.00	$ 55.00	$ 55.00	$57.32	$ 60.00
Oil positions:						
Fixed Price Swaps (NYMEX WTI):						
Hedged volume (MBbls)	1,458	1,474	1,214	1,214	4,197	—
Weighted average price ($/Bbl)	$ 53.43	$ 53.43	$ 52.04	$ 52.04	$52.05	$ —
Oil basis differential positions:						
ICE Brent-NYMEX WTI basic swaps:						
Hedged volume (MBbls)	360	364	368	368	1,095	—
Weighted average price ($/Bbl)	$ 1.21	$ 1.21	$ 1.21	$ 1.21	$1.17	$ —

We earn a premium on our sold calls at the time of sale. We make net settlement payments for prices above the indicated weighted-average price per barrel of WTI. If the calls expire unexercised, no payments are received.

For fixed-price swaps, we make net settlement payments for prices above the indicated weighted-average price per barrel of WTI and receive net settlement payments for prices below the indicated weighted average price per barrel of WTI.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For oil basis swaps, we make net settlement payments if the difference between Brent and WTI is greater than the indicated weighted average price per barrel and receive net settlement payments if the difference between Brent and WTI is below the indicated weighted average price per barrel. Our commodity derivatives are measured at fair value using industry-standard models with various inputs including forward prices and all are classified as Level 2 in the required fair value hierarchy for the periods presented. The following tables present the fair values (at gross and net) of our outstanding derivatives as of December 31, 2017 and December 31, 2016:

	Berry Corp. (Successor)			
	December 31, 2017			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Assets				
Commodity Contracts	Current assets	$ —	$ —	$ —
Commodity Contracts	Non-current assets	—	—	—
Liabilities				
Commodity Contracts	Current liabilities	(49,949)	—	(49,949)
Commodity Contracts	Non-current liabilities	(25,332)	—	(25,332)
Total derivatives		$ (75,281)	$ —	$ (75,281)

	Berry LLC (Predecessor)			
	December 31, 2016			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Assets				
Commodity Contracts	Current assets	$ 119	$ (119)	$ —
Commodity Contracts	Non-current assets	—	—	—
Liabilities				
Commodity Contracts	Current liabilities	(9,015)	119	(8,896)
Commodity Contracts	Non-current liabilities	(10,221)	—	(10,221)
Total derivatives		$ (19,117)	$ —	$ (19,117)

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves 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 us, which creates credit risk. We do not receive collateral from our counterparties.

The maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was zero at December 31, 2017 as we held no derivative asset positions. We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, our RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from Standards & Poor’s or Moody’s, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which mitigates the counterparty nonperformance risk somewhat.

Gains (Losses) on Derivatives

A summary of gains and losses on the derivatives included on the statements of operations is presented below:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
		(in thousands)	
Gains (losses) on oil and natural gas derivatives	$ (66,900)	$ 12,886	$ (15,781)
Lease operating expenses[1]	—	—	(4,605)
Total gains (losses) on oil and natural gas derivatives	$ (66,900)	$ 12,886	$ (20,386)

(1) Consists of gains and (losses) on derivatives that were entered into in March 2015 to hedge exposure to differentials in consuming areas.

For the ten months ended December 31, 2017, the two months ended February 28, 2017 and the year ended December 31, 2016, we received net cash settlements of approximately $3 million, $0.5 million, and $10 million, respectively.

Note 7—Lawsuits, Claims, Commitments and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

On May 11, 2016 our predecessor company filed the Chapter 11 Proceeding. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding. On the Effective Date the plan became effective and was implemented. The Chapter 11 Proceeding will, however, remain pending until final resolution of all outstanding claims.

In March 2017, Wells Fargo Bank, N.A. (“Wells”), the administrative agent under the Pre-Emergence Credit Facility, filed a motion in the Bankruptcy Court seeking payment of post-petition default interest in the amount of approximately $14 million. On November 13, 2017 the court denied Wells’ motion. Wells filed a notice of appeal on November 27, 2017, but, on February 5, 2018, Wells voluntarily dismissed the appeal against us. As a result, the Bankruptcy Court’s ruling in our favor is final.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2017 and December 31, 2016 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services. At December 31, 2017, purchase obligations of approximately $6 million represented a commitment to invest at least $9 million to extend an existing access road in connection with our Piceance assets, provide access to an existing road or construct a new access road, or to pay 50% of the difference between $12 million and the actual amount spent on such access road construction prior to the end of 2019. If we do not obtain extensions for the road obligation, obtain access to an existing road or construct a new access road, we may trigger the payment obligation which, if we were unable to negotiate resolution, would reduce our capital available for investment. As of December 31, 2017 we had entered into agreements to purchase natural gas for our operations in 2018 for approximately $14 million.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of December 31, 2017, we are not aware of material indemnity claims pending or threatened against us.

We have entered into operating lease agreements mainly for office space. Lease payments are expensed as part of general and administrative expenses. At December 31, 2017, future net minimum lease payments for non-cancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes and insurance and maintenance expense) totaled:

	Amount (in thousands)
2018	$ 1,349
2019	1,141
2020	85
2021	87
2022	88
Thereafter	—
Total minimum lease payments	$ 2,750

Note 8—Equity

On the Effective Date, Berry Corp. filed with the Secretary of State of the State of Delaware the Amended and Restated Certificate of Incorporation of Berry Corp. (the “Certificate of Incorporation”) and the Certificate of Designation of Series A Convertible Preferred Stock of Berry Petroleum Corporation (the “Series A Certificate of Designation”). Berry Corp. also adopted the Amended and Restated Bylaws of Berry Petroleum Corporation (the “Bylaws”) on the Effective Date. The Certificate of Incorporation provides that Berry Corp.’s authorized capital stock consists of 750,000,000 shares of common stock, par value $0.001 per share, and 250,000,000 shares of undesignated preferred stock, par value $0.001 per share.

Common Stock

The Plan contemplates the distribution of 40,000,000 shares of common stock in Berry Corp. On the Effective Date, 32,920,000 shares of common stock were distributed, pro rata, to holders of Unsecured Notes claims. The holders of Unsecured Claims received a right to receive their pro rata share of either (i) 7,080,000 shares of common stock in Berry Corp. or (ii) in the event that such holder irrevocably elected to receive a cash recovery, cash distributions from the Cash Distribution Pool. As of the Effective Date, all 7,080,000 shares of common stock in Berry Corp. distributable to holders of Unsecured Claims were reserved for future distributions pending resolution of disputed claims.

Voting Rights. Each share of common stock is entitled to one vote with respect to each matter on which holders of common stock are entitled to vote. Holders of common stock do not have cumulative voting rights.

Dividend Rights. Holders of common stock will be entitled to receive dividends, if any, as may be declared from time to time by our board of directors (“Board”) out of legally available funds.

Liquidation Rights. Upon liquidation, dissolution or winding up of the Company, subject to the rights of the holders of outstanding preferred stock, holders of common stock will be entitled to share ratably in the assets of the Company that are legally available for distribution to holders of common stock after payment of the Company's debts and other liabilities.

Holders of preferred stock that is outstanding may be entitled to dividend or liquidation preferences over holders of common stock, which means that the Company would have to pay distributions to holders of preferred stock before paying any distributions to holders of common stock.

Preemptive and Conversion Rights. Holders of common stock have no preemptive, conversion or other rights to subscribe for additional shares.

Preferred Stock

On the Effective Date, we issued 35,845,001 shares of preferred stock to participants in the rights offerings extended by the Company to certain holders of claims and in satisfaction of a backstop commitment fee for proceeds of $335 million.

Voting Rights. The Series A Preferred Stock is entitled to vote with holders of common stock, voting together as a single class, with respect to any and all matters subject to a stockholder vote, other than as required by law. Each share of preferred stock is entitled to a number of votes equal to the number of shares of common stock into which the share is convertible as of the record date.

Dividend Rights. Holders of Series A Preferred Stock are entitled to receive, when, as and if declared by the board of directors, cumulative dividends at a rate of 6.00% per annum either in cash or in additional shares of Series A Preferred Stock at the discretion of the board of directors. No dividends had been declared or paid as of December 31, 2017. The accreted cumulative and per share value of the dividends as of December 31, 2017 was approximately $18 million and $0.51, respectively.

In March 2018, the board of directors approved a cumulative paid-in-kind dividend on the Series A preferred stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 per share and approximately 1,825,000 shares in total. Also in March 2018, the board of directors approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A preferred stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018 to be paid in April 2018.

Liquidation Rights. If Berry Corp. liquidates, dissolves or winds up, holders of Series A Preferred Stock, in preference to any other series or class of capital stock of Berry Corp., will be entitled to share ratably in Berry Corp.'s assets that are legally available for distribution to holders of Series A Preferred Stock, after payment of its debts and other liabilities, in an amount per share of Series A Preferred Stock equal to the sum of (i) $10.00 plus (ii) any accrued and unpaid regular dividends.

The Series A Preferred Stock ranks senior to each other series or class of capital stock of Berry Corp. with respect to dividend rights, redemption rights, sale, merger or change of control preference and rights on liquidation, dissolution and winding up of the affairs of Berry Corp.

The Series A Preferred Stock is not subject to redemption by us or at the option of any holder of Series A Preferred Stock and is not entitled to a retirement or sinking fund. The Series A Preferred Stock contains no financial or operational covenants restricting our activities or our ability to raise capital.

Conversion Rights. The Series A Preferred Stock may be converted into a number of shares of common stock determined by the applicable conversion rate, 1.00 to 1.00 subject to dilution adjustments, (i) at the option of the holder at any time and (ii) at the option of Berry Corp. at any time after February 28, 2021, subject to certain conditions, including that the value of a share of common stock into which a share of Series A Preferred Stock is convertible is equal to or greater than $15.00, based on the volume-weighted average price for any 20-trading day period during the 30 trading days preceding conversion. From the time at which any shares of Series A Preferred Stock are deemed to

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

have been converted, the holder of such converted shares shall no longer be entitled to receive dividends on such Series A Preferred Stock (including any prior accrued or unpaid dividend).

Beneficial Conversion Feature

A beneficial conversion feature exists when the effective conversion price of a convertible security is less than the fair value per share on the commitment date. The conversion price of the preferred stock on the date of issuance was less than the estimated fair value of the common stock distributable under the Plan. Since the preferred stock is not mandatorily redeemable and is immediately convertible, the entire amount of the beneficial conversion feature was recognized immediately. In accordance with GAAP, we recorded a non-cash deemed dividend and a corresponding increase to additional paid in capital of approximately $28 million that is attributable to this beneficial conversion feature. The financial statement impact of the deemed dividend is eliminated in the consolidated statement of equity as adopting fresh-start accounting results in an entity with no beginning retained earnings or accumulated deficit.

Registration Rights Agreement

On the Effective Date, Berry Corp. entered into a registration rights agreement (the “Registration Rights Agreement”) with certain holders of the Unsecured Notes.

The Registration Rights Agreement requires Berry Corp. to file a shelf registration statement with the Securities and Exchange Commission (“SEC”) as soon as practicable following the Effective Date. The shelf registration statement will register the resale, on a delayed or continuous basis, of all Registrable Securities that have been timely designated for inclusion by specified Holders (as defined in the Registration Rights Agreement). Generally, “Registrable Securities” includes (i) common stock issued or to be issued by Berry Corp. under the Plan, (ii) preferred stock that was purchased by the participants in the Berry Rights Offerings and (iii) common stock into which the preferred stock converts, except that “Registrable Securities” does not include securities that have been sold under an effective registration statement or Rule 144 under the Securities Act. The Registration Rights Agreement will terminate when there are no longer any Registrable Securities outstanding.

2017 Omnibus Incentive Plan

On June 15, 2017, the Company adopted the 2017 Omnibus Incentive Plan. Our stock-based compensation program currently consists of restricted stock units (“RSUs”) and performance restricted stock units (“PRSUs”) available to certain employees and non-employee directors, which are equity-classified awards. The aggregate number of shares of common stock reserved for issuance pursuant to the 2017 Omnibus Incentive Plan is 6,876,500.

We included stock-based compensation expense of approximately $30,000 and $1.8 million, respectively, for the ten months ended December 31, 2017, and none for the periods ended February 28, 2017 and December 31, 2016 in lease operating expenses and general and administrative expenses.

A summary of the status of changes of unvested shares of restricted stock units under the 2017 Omnibus Incentive Plan is presented below:

	Number of shares	Weighted average Grant Date Fair Value
	(shares in thousands)	
February 28, 2017		
Granted	690	$ 10.12
Vested	(3)	$ 10.12
Forfeited	(5)	$ 10.12
December 31, 2017	682	$ 10.12

As of December 31, 2017, there was approximately $6.0 million of total unrecognized compensation cost related to the unvested restricted stock units. This cost is expected to be recognized over a period of almost three years.

The fair value of the PRSUs was determined on the grant date using a Monte Carlo simulation model based on applicable assumptions. The volatility is derived from corresponding peer group companies which we used in the absence of stock price history for our common stock at the date of grant. The expected life is based on the vesting period of the award. The risk-free rate represents the current three-year, yield-to-maturity U.S. Treasury Bonds as of the grant date. We do not expect to declare dividends to our common shareholders during the term of the PRSUs though such determinations ultimately rest with our board of directors. Estimates of the fair value may not accurately predict the value ultimately realized by the employees who receive the awards, and the ultimate value may not be indicative of the reasonableness of the original estimates of fair value made by us.

The grant date assumptions used in the Monte Carlo valuation of the outstanding PRSU awards were as follows:

	Grant Date
Risk-free interest rate	1.5%
Dividend yield	0%
Volatility factor	56.0%
Expected life (years)	3.0
Fair value of underlying common stock	$ 10.12

A summary of the status of changes of unvested shares of performance restricted stock units related to outstanding PRSUs under the 2017 Omnibus Incentive Plan is presented below:

	Number of shares	Weighted average Grant Date Fair Value
	(shares in thousands)	
February 28, 2017	—	
Granted	622	$ 7.09
Vested	—	—
Forfeited	—	—
December 31, 2017	622	$ 7.09

As of December 31, 2017, there were approximately $3.5 million of total unrecognized compensation costs related to the unvested performance restricted stock units. These costs are expected to be recognized over a period of almost three years.

Note 9—Defined Contribution Plan

We sponsor a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all full-time employees in providing for retirement or other future financial needs. The 401(k) plan provides for a matching contribution of up to 6% of an employee's eligible compensation. Employees are eligible to participate in the 401(k) plan on their date of hire.

We expensed approximately $0.8 million, $0 and $0 for the ten months ended December 31, 2017, the two months ended February 28, 2017 and the year ended December 31, 2016, respectively, under the provisions of the 401(k) plan.

Note 10—Income taxes

On the Effective Date, upon consummation of the Plan, the Successor became a C Corporation subject to federal and state income taxes. Prior to the consummation of the Plan, the Predecessor was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, the Predecessor did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of the Predecessor.

On December 22, 2017, the U.S. enacted the Tax Cuts and Jobs Act (the "Act") which made significant changes to the Internal Revenue Code of 1986, including lowering the maximum federal corporate income tax rate from 35% to 21%, repealing the corporate alternative minimum tax (“AMT”), and imposing limitations on the use of net operating losses arising in taxable years beginning after December 31, 2017. Although most of the provisions of the Act are not effective until tax years ending after December 31, 2017, the effects of new legislation are recognized upon enactment in accordance with GAAP. As a result, recognition of the tax effects of the Act is required in the consolidated financial statements for the fiscal year ended December 31, 2017.

The FASB and Securities and Exchange Commission (“SEC”) issued guidance on accounting for the tax effects of the Act. A company must reflect the income tax effects of those aspects of the Act for which the accounting is complete. To the extent that a company’s accounting for certain income tax effects of the Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply the applicable accounting on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Act. Accordingly, a measurement period may not extend beyond one year from the Act enactment date is allowed for companies to complete the relevant accounting analysis.

The Act reduces the corporate tax rate to 21%, effective January 1, 2018. We have recorded a provisional decrease in our net deferred tax asset before valuation allowance of $2.7 million, with a corresponding net adjustment to deferred income tax expense for the ten months ended December 31, 2017.

We must assess whether our valuation allowance analysis is affected by the Act. As discussed herein, our accounting for the valuation allowance required as a result of the Act is incomplete. However, we have recognized a $1.9 million provisional increase in the valuation allowance as a result of the Act.

Income tax expense (benefit) consisted of the following:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
		(in thousands)	
Current taxes:			
Federal	$ 465	$ —	$ —
State	450	221	127
	915	221	127
Deferred taxes:			
Federal	1,888	—	—
State	—	9	(11)
	$ 2,803	$ 230	$ 116

The federal current income tax expense relates to federal AMT liability.

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Federal statutory rate	35.0 %	35.0 %	35.0 %
State, net of federal tax benefit	7.2 %	— %	— %
Effect of permanent differences	(0.40)%	— %	— %
Tax reform—rate change[1]	(14.70)%	— %	— %
Income excluded from nontaxable entities	— %	(35.00)%	(35.00)%
Change in valuation allowance	(42.40)%	— %	— %
Effective tax rate	(15.30)%	— %	— %

(1) Includes the tax rate deduction. The impact of the rate change is fully offset in the Change in valuation allowance above.

Significant components of the deferred tax assets and liabilities are as follows:

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	December 31, 2017	December 31, 2016
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 1,556	$ —
Accruals	2,144	—
Asset retirement obligations	27,064	—
Derivative instruments	18,982	—
Tax credits	528	—
Other	867	—
Subtotal	51,141	—
Valuation allowance	(7,748)	—
Total	43,393	—
Deferred tax liabilities:		
Book tax differences in property basis	(45,281)	—
Total	(45,281)	—
Net deferred tax liability	$ (1,888)	$ —

We assessed the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of the existing deferred tax assets. A significant piece of objective negative evidence evaluated was the cumulative loss incurred in 2017 since the Effective Date. In the absence of other objectively verifiable evidence, including the reversal of existing federal and state temporary differences, such objective evidence limits the ability to consider other subjective evidence, such as our projections for future growth.

Under the Act, the net operating losses generated in years beginning after December 31, 2017 may only be carried forward and may only be used to offset up to 80% of taxable income. We considered this in our scheduling of the reversal of existing temporary differences, including deferred tax assets that are expected to generate future net operating losses subject to this limitation. Based on our evaluation, as of December 31, 2017, we recognized a valuation allowance of $7.7 million against our net deferred tax assets of $5.9 million. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as our projections for growth.

As of December 31, 2017, the Company had net operating loss (“NOL”) carryforwards for federal income tax reporting purposes of $7.4 million. This NOL carryforward balance is subject to the 20-year carryforward period and will expire in 2037.

We had $528,000 of AMT credit carryforwards as of December 31, 2017, which are refundable over a four year period beginning in tax year 2018 as a result of the Act. The AMT credit carryforward is being recognized as a deferred tax asset on our consolidated balance sheet rather than as a long-term receivable.

We had no material uncertain tax positions at December 31, 2017. We do not believe that it is reasonably possible that the total unrecognized benefits will significantly increase within the next 12 months.

We are subject to taxation in the United States and various state jurisdictions. We are not currently under audit by any federal or state taxing authority. The 2017 federal and state tax returns remain open to examination under the respective statute of limitations.

Note 11—Supplemental Disclosures to the Balance Sheets and Statements of Cash Flows

Other current assets reported on the balance sheets included the following:

	Berry Corp (Successor)	Berry LLC (Predecessor)
	December 31, 2017	December 31, 2016
	(in thousands)	
Prepaid expenses	$ 6,901	$ 4,149
Greenhouse gas allowances	—	3,087
Oil inventories, materials and supplies	5,938	3,299
Deferred financing costs	—	5,613
Other	1,227	70
Other current assets	$ 14,066	$ 16,218

Other noncurrent assets include approximately $20 million in deferred financing costs at December 31, 2017 and $15 million in greenhouse gas emission allowances at December 31, 2016.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts payable and accrued expenses on the balance sheets included the following:

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	December 31, 2017	December 31, 2016
	(in thousands)	
Accounts payable-trade	$ 15,469	$ 2,459
Accrued expenses	34,359	39,124
Royalties payable	25,793	6,858
Greenhouse gas liability	10,446	2,861
Taxes other than income tax liability	8,437	13,372
Other	3,373	4,324
	$ 97,877	$ 68,998

Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)		
Supplemental Disclosures of Significant Non-Cash Investing Activities:			
Increase in accrued liabilities related to purchases of property and equipment	$ 2,483	$ 2,249	$ 2,266
Supplemental Disclosures of Cash Payments:			
Interest, net of amounts capitalized	$ 14,276	$ 8,057	$ 57,759
Income taxes	$ 1,994	$ —	$ 347
Reorganization items, net	$ 1,732	$ 11,838	$ 19,116

Note 12—Related Party Transactions

The Predecessor had no employees. The employees of Linn Operating, Inc. ("Linn Operating"), a subsidiary of Linn Energy, provided services and support to the Company in accordance with an agency agreement and power of attorney between the Company and Linn Operating.

Transition Services and Separation Agreement ("TSSA")

On the Effective Date, Berry LLC entered into the TSSA with Linn Energy and certain of Linn Energy's affiliates and subsidiaries to facilitate the separation of our operations from Linn Energy's operations. Pursuant to the TSSA, (i) Linn Energy was required to provide, or cause to be provided, certain administrative, management, operating, and other services and support (the "Transition Services") to us during the transitional period from the Effective Date through the last day of the second full calendar month after the Effective Date (the "Transition Period"), (ii) we and the Linn Energy debtors separated our previously combined enterprise and (iii) the Linn Energy debtors transferred to Berry LLC certain assets that relate to our properties or business, in each case under the terms and conditions specified in the TSSA.

Under the TSSA, we reimbursed Linn Energy for any and all reasonable, third-party out-of-pocket costs and expenses, without markup, actually incurred by Linn Energy, to the extent documented, in connection with providing the Transition Services. Additionally, we paid Linn Energy a management fee of $6 million per month, prorated for partial months, during the Transition Period and paid $2.7 million per month, prorated for partial months, from the first day following the Transition Period through the last day of the second full calendar month thereafter (the “Separation Period”). During the Separation Period, the scope of the Transition Services was reduced to specified accounting and administrative functions. The Transition Period under the TSSA ended April 30, 2017, and the Separation Period ended June 30, 2017.

For the ten months ended December 31, 2017, we incurred management fee expenses of approximately $17 million under the TSSA. Since the agreement commenced on the Effective Date, no expenses were incurred for the periods ended February 28, 2017. For the year ended December 31, 2016, the Predecessor incurred management fee expenses of $69 million. At December 31, 2016, we had a receivable due from Linn Energy of $3.0 million included in “accounts receivable, net” and approximately $43 million due to Linn Energy included in “liabilities subject to compromise” on the balance sheet at December 31, 2016. We had none at December 31, 2017.

The Predecessor made no cash distributions to Linn Energy during the year ended December 31, 2016.

One of Linn Energy’s former directors is the President and Chief Executive Officer of Superior Energy Services, Inc. (“Superior”) which provided oilfield services to the Predecessor. The Predecessor incurred no significant expenditures related to services rendered by Superior and its subsidiaries for the two months ended February 28, 2017 and the year ended December 31, 2016.

Note 13—Acquisitions and Divestitures

On July 31, 2017, we divested our 78% working interest in the Hugoton natural gas field located in Southwest Kansas and the Oklahoma Panhandle because we deemed it a non-core asset. This resulted in approximately $234 million of proceeds and a $23 million gain.

Also on July 31, 2017, we acquired the remaining 84% working interest in the South Belridge Hill property located in Kern County, California, in which we previously owned a 16% working interest. We purchased the properties for approximately $249 million.

Note 14—Earnings Per Share

Our Predecessor Company was organized as a limited liability company and, as such, did not issue any stock. Accordingly, we have not presented earnings per share calculations for the Predecessor Company periods.

We calculate basic earnings (loss) per share by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding during each period. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, such as those shares contemplated by the Plan, are considered common shares outstanding and are included in the computation of net income (loss) per share. Accordingly, the 40 million shares of common stock contemplated by the Plan, without regard to actual issuance dates, were included in the computation of net income (loss) per share for the ten months ended December 31, 2017. The actual amount of our common stock that will be issued from the 7,080,000 shares reserved for Unsecured Claims and included in the 40 million shares above, cannot be known until all claims are settled, adjustments have been made based on the stock to be received by Unsecured Claims and claims under the Unsecured Notes and, the final number of shares of common stock to be received per dollar of Unsecured Claims, is known.

The convertible preferred stock is not a participating security, therefore, we calculated diluted EPS using the “if-converted’ method where the preferred dividends are added back to the numerator and the convertible preferred stock is assumed to be converted at the beginning of the period. No incremental shares of convertible preferred stock were included in the diluted EPS calculation as their effect was antidilutive under the “if-converted” method. Additionally, no incremental shares of potentially dilutive RSUs or PRSUs were included in the diluted EPS calculation as their effect was antidilutive.

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands except per share amounts)		
Basic EPS calculation			
Net loss	$ (21,068)	n/a	n/a
less: Undeclared dividends on Series A preferred stock	(18,248)	n/a	n/a
Net loss available to common stockholders	$ (39,316)	n/a	n/a
Weighted-average shares of common stock outstanding	32,920	n/a	n/a
Shares of common stock distributable to holders of Unsecured Claims (note 2)	7,080	n/a	n/a
Weighted-average common shares outstanding-basic	40,000	n/a	n/a
Basic Earnings (loss) per share	$ (0.98)	n/a	n/a
Diluted EPS calculation			
Net loss	$ (21,068)	n/a	n/a
less: Undeclared dividends on Series A preferred stock	(18,248)	n/a	n/a
Net loss available to common stockholders	$ (39,316)	n/a	n/a
Weighted-average shares of common stock outstanding	32,920	n/a	n/a
Shares of common stock distributable to holders of Unsecured Claims (note 2)	7,080	n/a	n/a
Weighted-average common shares outstanding-basic	40,000	n/a	n/a
Dilutive effect of potentially dilutive securities	—	n/a	n/a
Weighted-average common shares outstanding-diluted	40,000	n/a	n/a
Diluted Earnings (loss) per share	$ (0.98)	n/a	n/a

Note 15—Subsequent Events

As discussed in Note 1, in November 2016, the FASB issued rules intended to address the diversity in practice in classification and presentation of changes in restricted cash on the statement of cash flows. We adopted these rules on January 1, 2018, on a retrospective basis. The adoption of these rules resulted in the inclusion of restricted cash amounts in our beginning and ending cash balances on the statement of cash flows and disclosure reconciling cash and cash equivalents presented on the balance sheets to cash, cash equivalents and restricted cash on the statements of cash flows.

BERRY PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides a reconciliation of Cash, cash equivalents and restricted cash as reported in the Consolidated Statements of Cash Flows to the line items within the Consolidated Balance Sheets:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
		(in thousands)	
Beginning of Period			
Cash and cash equivalents	$ 32,049	$ 30,483	$ 1,023
Restricted cash	52,860	197,793	250,359
Restricted cash in other noncurrent assets	125	128	128
Cash, cash equivalents and restricted cash	$ 85,034	$ 228,404	$ 251,510
Ending of Period			
Cash and cash equivalents	$ 33,905	$ 32,049	$ 30,483
Restricted cash	34,833	52,860	197,793
Restricted cash in other noncurrent assets	—	125	128
Cash, cash equivalents and restricted cash	$ 68,738	$ 85,034	$ 228,404

SUPPLEMENTAL OIL & NATURAL GAS DATA
(Unaudited)

The following discussion and analysis should be read in conjunction with the "Financial Statements" and "Notes to Financial Statements".

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)		
Property acquisition costs:			
Proved	$ 249,338	—	$ 1,545
Unproved	—	—	—
Exploration costs	—	—	—
Development costs	60,381	4,544	13,091
Total costs incurred	$ 309,719	4,544	14,636

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil, natural gas and NGL production activities with applicable accumulated depletion and amortization are presented below:

	Berry Corp (Successor)	Berry LLC (Predecessor)
	December 31, 2017	December 31, 2016
	(in thousands)	
Oil, natural gas, and NGLs:		
Proved properties	$ 911,478	$ 4,262,155
Unproved properties	517,037	764,655
	1,428,515	5,026,810
Less accumulated depletion and amortization	(58,525)	(2,789,368)
	$ 1,369,990	$ 2,237,442

Results of Oil and Natural Gas Producing Activities

The results of operations for oil, natural gas and NGL producing activities (excluding items such as corporate overhead, interest costs and reorganization items, net) are presented below:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)		
Net revenues from production:			
Oil, natural gas and NGL sales	$ 357,928	74,120	$ 392,345
Electricity sales	21,972	3,655	23,204
Other production-related revenue	6,569	2,003	10,899
	386,469	79,778	426,448
Operating costs for production:			
Lease operating expenses	149,599	28,238	185,056
Electricity generation expenses	14,894	3,197	17,133
Transportation expenses	19,238	6,194	41,619
Production-related general and administrative expenses	5,786	—	—
Taxes, other than income taxes	34,211	5,212	24,982
Other production-related costs	2,320	653	3,100
	226,048	43,494	271,890
Other costs:			
Depreciation, depletion and amortization	67,051	26,743	169,605
Impairment of long-lived assets	—	—	1,030,588
(Gains) losses on sale of assets and other, net	(22,930)	—	(7)
	44,121	26,743	1,200,186
Income tax expense (benefit)	45,887	230	116
Results of operations	$ 70,412	9,311	$ (1,045,743)

Income tax is calculated by applying the current federal and state statutory tax rates to the revenues after deducting costs, which include DD&A allowances, after giving effect to permanent differences. The federal statutory rates for the periods presented above were not adjusted by recently enacted Tax Reform Legislation. There is no federal tax provision included in the Predecessors results above because the Predecessor was not subject to federal income taxes during those periods. The income tax amount included in the Predecessor’s results above relates to Texas margin tax expense. Limited liability companies are subject to Texas margin tax. See Note 10 for additional information about income taxes.

Proved Oil, Natural Gas and NGL Reserves

The proved reserves of oil and natural gas of the Company have been prepared by the independent engineering firm, DeGolyer and MacNaughton. In accordance with Securities and Exchange Commission ("SEC") regulations, reserves at December 31, 2017 and December 31, 2016, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the U.S., is shown below:

	Berry Corp. (Successor)			
	Year Ended December 31, 2017			
	Oil MBbls	NGL MBbls	Natural Gas MMcf	Total MBoe
Total proved reserves:				
Beginning of year (Predecessor)	55,876	15,078	372,760	133,080
Revisions of previous estimates	9,089	431	32,144	14,878
Sales of proved reserves in place	(13)	(13,329)	(285,168)	(60,870)
Purchase of proved reserves in place	24,332	—	—	24,332
Extensions and discoveries	18,783	—	136,719	41,570
Production	(7,471)	(909)	(19,351)	(11,605)
End of year	100,596	1,271	237,104	141,385
Proved developed reserves:				
Beginning of year (Predecessor)	55,422	15,078	372,760	132,626
End of year	68,490	1,271	100,384	86,492
Proved undeveloped reserves:				
Beginning of year (Predecessor)	454	—	—	454
End of year	32,106	—	136,720	54,893

	Berry LLC (Predecessor)			
	Year Ended December 31, 2016			
	Oil MBbls	NGL MBbls	Natural Gas MMcf	Total MBoe
Total proved reserves:				
Beginning of year	93,892	16,953	387,848	175,487
Revisions of previous estimates	(31,350)	(568)	13,311	(29,701)
Extensions and discoveries	1,797	—	178	1,827
Production	(8,463)	(1,307)	(28,577)	(14,533)
End of year	55,876	15,078	372,760	133,080
Proved developed reserves:				
Beginning of year	93,892	16,953	387,848	175,487
End of year	55,422	15,078	372,760	132,626
Proved undeveloped reserves:				
Beginning of year	—	—	—	—
End of year	454	—	—	454

The tables above include changes in estimated quantities of natural gas reserves shown in Boe using the ratio of six Mcf to one barrel.

Proved reserves increased by approximately 8,305 MBoe to approximately 141,385 MBoe for the year ended December 31, 2017, from 133,080 MBoe for the year ended December 31, 2016. The year ended December 31, 2017, includes approximately 14,878 MBoe of positive revisions of previous estimates due to higher commodity prices. Extensions and discoveries, contributed approximately 41,570 MBoe to the increase in proved reserves, primarily due to the certainty attained in the Company's future commitment to capital as a result of its emergence from bankruptcy allowing inclusion of PUDs previously excluded due to the SEC five-year development limitation on PUDs, as well as from 93 productive wells drilled during the year. Lastly, the Hugoton Disposition and Hill Acquisition had a net negative impact on proved reserves of approximately 36,538 MBoe (negative impact on reserves from the Hugoton Disposition of approximately 60,870 MBoe offset by the positive impact on reserves from the Hill Acquisition of approximately 24,332 MBoe).

Proved reserves decreased by approximately 42,407 MBoe to approximately 133,080 MBoe for the year ended December 31, 2016, from 175,487 MBoe for the year ended December 31, 2015. The year ended December 31, 2016, includes approximately 29,701 MBoe of negative revisions of previous estimates (22,729 MBoe due to asset performance and 6,972 MBoe due to lower commodity prices). In addition, extensions and discoveries, primarily from 23 productive wells drilled during the year, contributed approximately 1,827 MBoe to the increase in proved reserves.

Standardized Measure of Discounted Future Net Cash Flows

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying applicable prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because the Predecessor was not subject to federal income taxes. Limited liability companies are subject to Texas margin tax; however, these amounts were not material. See Note 10 for additional information about income taxes.

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	December 31,	
	2017	2016
	(in thousands)	
Future estimated revenues	$ 5,580,448	$ 3,131,758
Future estimated production costs	(2,725,548)	(1,893,608)
Future estimated development costs	(678,312)	(220,374)
Future income taxes	(365,330)	—
Future net cash flows	1,811,258	1,017,776
10% annual discount for estimated timing of cash flows	(833,910)	(421,554)
Standardized measure of discounted future net cash flows	$ 977,348	$ 596,222
Representative prices:(1)		
ICE Brent Oil (Bbl)	$ 54.42	
NYMEX WTI Oil (Bbl)		$ 42.64
NYMEX Henry Hub Natural gas (MMBtu)	$ 2.98	$ 2.48

(1) In accordance with SEC regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

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

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	December 31,	
	2017	2016
	(in thousands)	
Standardized measure—beginning of year	$ 596,222	$ 995,372
Sales and transfers of oil, natural gas and NGL produced during the period	(189,355)	(140,688)
Changes in estimated future development costs	6,399	66,386
Net change in sales and transfer prices and production costs related to future production	224,064	(242,982)
Extensions, discoveries and improved recovery	157,717	21,610
Purchase of minerals in place	317,616	—
Sales of minerals in place	(141,998)	—
Previously estimated development costs incurred during the period	6,913	—
Net change due to revisions in quantity estimates	124,609	(158,474)
Accretion of discount	59,622	99,537
Net change in income taxes	(136,810)	—
Changes in production rates and other	(47,651)	(44,539)
Net increase (decrease)	381,126	(399,150)
Standardized measure—end of year	$ 977,348	$ 596,222

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

BERRY PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY FINANCIAL DATA
(Unaudited)

	Berry LLC (Predecessor)	Berry Corp. (Successor)			
			Quarters Ended		
	Two Months Ended February 28	One Month Ended March 31	June 30	September 30	December 31
		(in thousands)			
2017:					
Total revenues and other[(1)]	$ 92,718	$ 59,655	$ 134,721	$ 69,910	$ 55,382
Total expenses[(2)]	79,607	37,783	113,380	101,397	92,189
(Gains) losses on sale of assets and other, net	(183)	—	5	(20,692)	(2,243)
Reorganization items, net, expense (income)	507,720	1,306	(713)	408	730
Net income (loss)	(502,964)	11,377	12,119	(9,684)	(34,880)
Net income (loss) available to common stockholders	(502,964)	9,585	6,715	(15,169)	(40,447)
Earnings (loss) per share attributable to common stockholders:					
Basic[(3)]	n/a	$ 0.24	$ 0.17	$ (0.38)	$ (1.01)
Diluted[(3)]	n/a	$ 0.15	$ 0.16	$ (0.38)	$ (1.01)

	Berry LLC (Predecessor)[(3)]			
	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
2016:				
Total revenues and other[(1)]	$ 91,266	$ 108,639	$ 113,225	$ 97,861
Total expenses[(2)]	1,196,393	133,868	111,600	118,207
(Gains) losses on sale of assets and other, net	(192)	425	(370)	28
Reorganization items, net expense (income)	—	(49,086)	87,915	33,833
Net income (loss)	(1,124,819)	6,840	(98,438)	(66,779)

(1) Includes net derivative gains (losses).
(2) Includes the following expenses: lease operating, transportation, electricity generation, marketing, general and administrative, depreciation, depletion and amortization, impairment of long-lived assets and taxes, other than income taxes.
(3) Our predecessor company was organized as a limited liability company and, as such, did not issue any stock. Accordingly, we have not presented earnings per share calculations for the predecessor company periods.

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	Berry Corp. (Successor)	
	September 30, 2018	**December 31, 2017**
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,856	$ 33,905
Accounts receivable, net of allowance for doubtful accounts of $950 at September 30, 2018 and $970 at December 31, 2017	65,757	54,720
Restricted cash	57	34,833
Other current assets	13,233	14,066
Total current assets	102,903	137,524
Noncurrent assets:		
Oil and natural gas properties	1,419,589	1,342,453
Accumulated depletion and amortization	(106,128)	(54,785)
Total oil and natural gas properties, net	1,313,461	1,287,668
Other property and equipment	116,149	104,879
Accumulated depreciation	(11,244)	(5,356)
Total other property and equipment, net	104,905	99,523
Other noncurrent assets	18,338	21,687
Total assets	$ 1,539,607	$ 1,546,402
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 117,801	$ 97,877
Derivative instruments	26,409	49,949
Liabilities subject to compromise	57	34,833
Total current liabilities	144,267	182,659
Noncurrent liabilities:		
Long-term debt	391,512	379,000
Derivative instruments	4,664	25,332
Deferred income taxes	5,033	1,888
Asset retirement obligation	89,404	94,509
Other noncurrent liabilities	15,617	3,704
Commitments and Contingencies - Note 5		
Equity:		
Series A preferred stock ($.001 par value, 250,000,000 shares authorized and none outstanding at September 30, 2018 and 35,845,001 shares outstanding at December 31, 2017)	—	335,000
Common stock ($.001 par value, 750,000,000 shares authorized and 81,364,933 shares outstanding at September 30, 2018 and 32,920,000 outstanding at December 31, 2017)	81	33
Additional paid-in-capital	915,028	545,345
Treasury stock, at cost	(20,265)	—
Retained earnings (Accumulated deficit)	(5,734)	(21,068)
Total equity	889,110	859,310
Total liabilities and equity	$ 1,539,607	$ 1,546,402

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Berry Corp. (Successor)				Berry LLC (Predecessor)
	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands, except per share amounts)				
Revenues and other:					
Oil, natural gas and natural gas liquids sales	$ 147,004	$ 101,763	$ 410,013	$ 237,324	$ 74,120
Electricity sales	14,268	8,914	25,691	15,517	3,655
Gains (losses) on oil derivatives	(18,994)	(42,443)	(131,781)	5,642	12,886
Marketing revenues	486	811	1,788	1,901	633
Other revenues	183	865	500	3,902	1,424
Total revenues and other	142,947	69,910	306,211	264,286	92,718
Expenses and other:					
Lease operating expenses	51,649	46,224	137,468	105,014	28,238
Electricity generation expenses	6,130	4,580	13,855	10,193	3,197
Transportation expenses	2,318	5,586	7,640	18,645	6,194
Marketing expenses	437	674	1,424	1,674	653
General and administrative expenses	13,429	11,729	37,896	43,529	7,964
Depreciation, depletion, amortization and accretion	21,729	20,822	62,017	48,393	28,149
Taxes, other than income taxes	8,317	11,782	25,288	25,112	5,212
(Gains) losses on natural gas derivatives	(1,879)	—	(1,879)	—	—
(Gains) losses on sale of assets and other, net	400	(20,692)	522	(20,687)	(183)
Total expenses and other	102,530	80,705	284,231	231,873	79,424
Other income (expenses):					
Interest expense	(9,877)	(5,882)	(26,828)	(12,482)	(8,245)
Other, net	347	1,155	135	4,071	(63)
Total other income (expenses)	(9,530)	(4,727)	(26,693)	(8,411)	(8,308)
Reorganization items, net	13,781	(408)	23,192	(1,001)	(507,720)
Income (loss) before income taxes	44,668	(15,930)	18,479	23,001	(502,734)
Income tax expense (benefit)	7,683	(6,246)	3,145	9,189	230
Net income (loss)	36,985	(9,684)	15,334	13,812	$ (502,964)
Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(97,942)	(12,681)	n/a
Net income (loss) attributable to common stockholders	$ (49,657)	$ (15,169)	$ (82,608)	$ 1,131	n/a
Net income (loss) per share attributable to common stockholders:					
Basic	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a
Diluted	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Berry Corp. (Successor)					
	Nine-Month Period Ended September 30, 2018					
	Series A Preferred Stock	Common Stock	Additional Paid in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
	(in thousands)					
December 31, 2017	$ 335,000	$ 33	$ 545,345	$ —	$ (21,068)	$ 859,310
Stock based compensation	—	—	1,042	—	—	1,042
Cash dividends declared on Series A preferred stock, $0.158/share	—	—	(5,650)	—	—	(5,650)
Net income	—	—	—	—	6,410	6,410
March 31, 2018	335,000	33	540,737	—	(14,658)	861,112
Stock based compensation	—	—	1,278	—	—	1,278
Shares withheld for payment of taxes on equity awards	—	—	(176)	—	—	(176)
Cash dividends declared on Series A preferred stock, $0.15/share	—	—	(5,651)	—	—	(5,651)
Purchase of rights to common stock	—	—	—	(20,006)	—	(20,006)
Net loss	—	—	—	—	(28,061)	(28,061)
June 30, 2018	335,000	33	536,188	(20,006)	(42,719)	808,496
Conversion of Series A preferred stock into common stock	(335,000)	40	334,960	—	—	—
Cash payment to Series A preferred stockholders	—	—	(60,273)	—	—	(60,273)
Issuance of common stock in initial public offering	—	10	134,352	—	—	134,362
Repurchase of common stock	—	(2)	(23,710)	—	—	(23,712)
Shares withheld for payment of taxes on equity awards	—	—	(246)	—	—	(246)
Stock based compensation	—	—	1,188	—	—	1,188
Purchase of rights to common stock	—	—	—	(259)	—	(259)
Dividends declared on common stock, $0.09/share	—	—	(7,431)	—	—	(7,431)
Net income	—	—	—	—	36,985	36,985
September 30, 2018	$ —	$ 81	$ 915,028	$ (20,265)	$ (5,734)	$ 889,110

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Nine-Month Period Ended September 30, 2017, including Successor and Predecessor Periods					
	Series A Preferred Stock	Common Stock	Additional Paid in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
December 31, 2016	$ —	$ —	$ 2,798,713	$ —	$ (2,295,750)	$ 502,963
Net loss	—	—	—	—	(502,964)	(502,964)
Other	—	—	1	—	—	1
Cancellation of Predecessor Equity	—	—	(2,798,714)	—	2,798,714	—
Predecessor February 28, 2017	—	—	—	—	—	—
Issuance of Series A convertible preferred stock	335,000	—	—	—	—	335,000
Issuance of common stock	—	33	527,794	—	—	527,827
Fresh start ad valorem tax reclassification	—	—	15,700	—	—	15,700
Successor February 28, 2017	335,000	33	543,494	—	—	878,527
Net income	—	—	—	—	11,377	11,377
March 31, 2017	335,000	33	543,494	—	11,377	889,904
Net income	—	—	—	—	12,119	12,119
June 30, 2017	335,000	33	543,494	—	23,496	902,023
Stock based compensation	—	—	902	—	—	902
Net loss	—	—	—	—	(9,684)	(9,684)
September 30, 2017	$ 335,000	$ 33	$ 544,396	$ —	$ 13,812	$ 893,241

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

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BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
		(in thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 15,334	$ 13,812	$ (502,964)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion, amortization and accretion	62,017	48,393	28,149
Amortization and write-off of deferred financing fees	4,042	926	416
Stock-based compensation expense	3,502	902	—
Deferred income taxes	3,146	7,196	9
(Decrease) increase in allowance for doubtful accounts	(20)	970	—
Derivative activities:			
Total (gains) losses	129,902	(5,642)	(12,886)
Cash settlements	(47,161)	9,902	534
Cash settlements on early-terminated derivatives	(126,949)	—	—
(Gains) losses on sale of assets and other, net	522	(20,687)	(25)
Reorganization items, net	(24,199)	1,376	501,872
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(11,546)	(3,095)	(9,152)
(Increase) decrease in other assets	(774)	(11,397)	(2,842)
Increase (decrease) in accounts payable and accrued expenses	5,574	11,416	18,330
Increase (decrease) in other liabilities	(6,056)	16,433	990
Net cash provided by (used in) operating activities	7,334	70,505	22,431
Cash flows from investing activities:			
Capital expenditures:			
Development of oil and natural gas properties	(74,447)	(38,445)	(859)
Purchases of other property and equipment	(11,305)	(11,497)	(2,299)
Proceeds from sale of property, plant, equipment and other	3,377	234,823	25
Acquisition of properties	—	(259,444)	—
Net cash used in investing activities	(82,375)	(74,563)	(3,133)
Cash flows from financing activities:			
Repayments on new credit facility	(576,210)	(11,800)	—
Borrowings under new credit facility	197,210	390,800	—
IPO proceeds net of issuance costs	134,362	—	—
Repurchase of common stock	(23,712)	—	—
Payment to preferred stockholders in conversion	(60,273)	—	—
Issuance of 2026 Senior Unsecured Notes	400,000	—	—
Dividends paid on Series A preferred stock	(11,301)	—	—
Purchase of treasury stock	(20,265)	—	—

Shares withheld for payment of taxes on equity awards	(422)	—	—
Debt issuance costs	(9,173)	(22,049)	—
Borrowings on emergence credit facility	—	51,000	—
Repayments on emergence credit facility	—	(451,000)	—
Proceeds from sale of Series A preferred stock	—	—	335,000
Repayments on pre-emergence credit facility	—	—	(497,668)
Net cash provided by (used in) financing activities	30,216	(43,049)	(162,668)
Net decrease in cash, cash equivalents and restricted cash	(44,825)	(47,107)	(143,370)
Cash, cash equivalents and restricted cash:			
Beginning	68,738	85,034	228,404
Ending	$ 23,913	$ 37,927	$ 85,034

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

BERRY PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)
September 30, 2018

Note 1 - Basis of Presentation

"Berry Corp." refers to Berry Petroleum Corporation, a Delaware corporation which, on and after February 28, 2017 is the sole member of Berry Petroleum Company, LLC.

"Berry LLC" refers to Berry Petroleum Company, LLC, a Delaware limited liability company.

As the context may require, the "Company", "we", "our" or similar words refer to (i) Berry Corp. (the "Successor") and Berry LLC, its consolidated subsidiary, as of and after February 28, 2017, as a whole or (ii) either Berry Corp. or Berry LLC on an individual basis as of and after February 28, 2017. References to historical activities of the "Company" prior to February 28, 2017, refer to activities of Berry LLC (the "Predecessor").

"Linn Energy" refers to Linn Energy, LLC, a Delaware limited liability company of which Berry LLC was formerly a wholly-owned, indirect subsidiary and LinnCo, LLC ("LinnCo" and, together with Linn Energy, the "Linn Entities").

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law on February 13, 2017. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located in the United States ("U.S."), in California (in the San Joaquin and Ventura Basins), Utah (in the Uinta Basin), Colorado (in the Piceance Basin) and east Texas.

In July, we completed the initial public offering ("IPO") of our common stock and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY.

Principles of Consolidation and Reporting

The information reported herein reflects all adjustments (consisting of normal recurring adjustments) that are, in the opinion of management, necessary for the fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted under Securities and Exchange Commission ("SEC") rules and regulations. The results reported in these unaudited condensed consolidated financial statements may not accurately forecast results for future periods. This report should be read in conjunction with the financial statements and notes in the Company's audited financial statements for the year ended December 31, 2017 presented in our final prospectus dated July 25, 2018 as filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on July 27, 2018 (the "prospectus").

The condensed consolidated financial statements have been prepared in conformity with GAAP and include the accounts of the Successor and its wholly owned subsidiary after February 28, 2017 and the accounts of the Predecessor prior to February 28, 2017. All significant intercompany transactions and balances have been eliminated upon consolidation. For oil and gas exploration and production joint ventures in which we have a direct working interest, we account for our proportionate share of assets, liabilities, revenue, expense and cash flows within the relevant lines of the financial statements.

Bankruptcy Accounting

Upon emergence from bankruptcy on February 28, 2017, we adopted fresh start accounting which resulted in Berry Corp. becoming the financial reporting entity. As a result of the application of fresh start accounting and the effects of the implementation of the Plan (see Note 2 for definition), the condensed consolidated financial statements on or after February 28, 2017 are not comparable to the condensed consolidated financial statements prior to that date.

Use of Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with GAAP required management of the Company to make informed estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses.

As fair value is a market-based measurement, it was determined based on the assumptions that we believe market participants would use. We based these assumptions on management's best estimates and judgment. Management evaluates its assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, that management believes to be reasonable under the circumstances. Such assumptions are adjusted when management determines that facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates.

Estimates that are particularly significant to our financial statements include estimates of our reserves of oil and gas, future cash flows from oil and gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. In addition, as part of fresh-start accounting, we made estimates and assumptions related to our reorganization value, liabilities subject to compromise and the fair value of assets and liabilities recorded.

Accounting and Disclosure Changes

Recently Adopted Accounting Standards

In August 2018, the SEC issued a final rule requiring registrants to analyze and disclose changes in stockholders' equity in the form of a reconciliation for the current and comparative year-to-date interim periods with subtotals for each interim period. We adopted this rule in the quarter ended September 30, 2018 and modified our statements of equity accordingly.

In March 2016, the Financial Accounting Standards Board (“FASB”) issued rules to improve the accounting for share-based payment transactions. We early-adopted these rules retrospectively on April 1, 2018 and as a result are reporting cash paid to tax authorities when we withhold shares from an employee's award as a cash outflow for financing activities on the statement of cash flows. There was no change to the other financial statements as a result of adopting these rules.

In November 2016, the FASB issued rules intended to address the diversity in practice in classification and presentation of changes in restricted cash on the statement of cash flows. We adopted these rules retrospectively on January 1, 2018, as a result of which we included restricted cash amounts in our beginning and ending cash balances on the statement of cash flows and included a disclosure reconciling cash and cash equivalents presented on the balance sheets to cash, cash equivalents and restricted cash on the statement of cash flows.

New Accounting Standards Issued, But Not Yet Adopted

In February 2016, the FASB issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and do not expect a material impact on our consolidated results of operations.

During 2016, the FASB issued rules clarifying the new revenue recognition standard issued in 2014. The new rules are intended to improve and converge the financial reporting requirements for revenue from contracts with customers. We are an emerging growth company and have elected to delay adoption of these rules until they are applicable to non-

SEC issuers which is for fiscal years beginning after December 31, 2018. We do not expect the adoption of these rules to materially change our reporting of revenue, however, we expect that certain amounts currently reported as expense will be reported as offsets to revenue.

Note 2 - Emergence from Voluntary Reorganization under Chapter 11

On May 11, 2016 our predecessor company filed bankruptcy. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16–60040 (the "Chapter 11 Proceeding"). On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding (the "Plan"). On February 28, 2017, the Effective Date occurred and the Plan became effective and was implemented. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party–in–interest to reopen the case including with respect to certain, immaterial remaining matters.

Reorganization Items, Net

We have incurred and continue to incur expenses associated with the reorganization. Reorganization items, net represent costs and gains directly associated with the Chapter 11 Proceeding, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined. The following table summarizes the components of reorganization items included on the condensed consolidated statements of operations:

	Berry Corp. (Successor)				Berry LLC (Predecessor)
	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)				
Return of undistributed funds from Cash Distribution Pool (1)	$ 13,799	$ —	$ 22,799	$ —	$ —
Refund of pre-emergence prepaid costs	—	—	579	—	—
Gain on resolution of pre-emergence liabilities	—	—	1,634	—	—
Linn Energy bankruptcy claim receipt	1,500	—	1,500	—	—
Gain on settlement of liabilities subject to compromise	—	—	—	—	421,774
Fresh start valuation adjustments	—	—	—	—	(920,699)
Legal and other professional advisory fees	(713)	(408)	(2,515)	(296)	(19,481)
Other	(805)	—	(805)	(705)	10,686
Reorganization items, net	$ 13,781	$ (408)	$ 23,192	$ (1,001)	$ (507,720)

(1) Among other things, the holders of our Predecessor's Unsecured Notes (as defined below) received a right to their pro rata share of either 32,920,000 shares of common stock in Berry Corp. or, for those non-accredited investors holding our Predecessor's unsecured notes (the "Unsecured Notes") that irrevocably elected to receive a cash recovery, cash distributions from a $35 million cash distribution pool (the “Cash Distribution Pool”).

Liabilities Subject to Compromise

Liabilities subject to compromise related to our 2017 emergence from bankruptcy decreased from approximately $35 million as of December 31, 2017 to approximately $0.1 million as of September 30, 2018. Activity for our liabilities subject to compromise for the nine months ended September 30, 2018 included the return of $23 million in undistributed funds from restricted cash and approximately $12 million in settlement payments to general unsecured creditors and other payments of professional fees incurred to settle these claims.

Note 3 - Debt

The following table summarizes our outstanding debt:

	September 30, 2018	December 31, 2017	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ —	$ 379,000	variable rates of 4.5% (2018) and 4.8% (2017), respectively	June 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves
2026 Notes	400,000	—	7.00%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	379,000			
Less: Debt Issuance Costs	(8,488)	—			
Long-Term Debt, net	$ 391,512	$ 379,000			

At September 30, 2018 and December 31, 2017, debt issuance costs for the RBL Facility (as defined below) reported in "other noncurrent assets" on the balance sheet were approximately $17 million and $21 million net of amortization, respectively. The amortization of debt issuance costs is presented in interest expense on the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amount of the RBL Facility approximates fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 senior unsecured notes was approximately $416 million at September 30, 2018.

Credit Facilities

On July 31, 2017, we entered into a credit agreement (“RBL Facility”), with Wells Fargo Bank, N.A. as administrative agent and certain lenders with up to $1.5 billion of commitments, subject to a reserves-based borrowing base. In connection with the issuance of the 2026 Notes (as defined below), the RBL Facility borrowing base was set at $400 million, which incorporated a $100 million reduction, or 25% of the face value of the 2026 Notes. In March 2018, we completed a borrowing base redetermination which reaffirmed our borrowing base at $400 million with an elected commitment feature that allows us to increase the RBL Facility to $575 million with lender approval.

As of September 30, 2018, the financial performance covenants under our RBL Facility were (i) a leverage ratio of no more than 4.00 to 1.00 and (ii) a current ratio of at least 1.00 to 1.00. At September 30, 2018, our actual ratios were 1.85 to 1.00 and 4.21 to 1.00, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants as of September 30, 2018.

As of September 30, 2018, we had approximately $393 million of available borrowing capacity under the RBL Facility.

As of September 30, 2018 and December 31, 2017, we had letters of credit outstanding of approximately $7 million and $21 million, respectively, under our RBL facility. These letters of credit were issued to support ordinary course of business marketing, insurance, regulatory and other matters.

In July and August 2018, we paid down approximately $105 million on the RBL Facility from the net proceeds we received in the IPO of our common stock (see Note 6).

Senior Unsecured Notes Offering

In February 2018, we completed a private issuance of $400 million in aggregate principal amount of 7.00% senior unsecured notes due 2026 (the “2026 Notes”), which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers’ discount. We used a portion of the net proceeds from the issuance of the 2026 Notes to repay borrowings under the RBL Facility and used the remainder for general corporate purposes.

Note 4 - Derivatives

We have hedged a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices and we target covering our operating expenses and fixed charges, including maintenance capital expenditures, for up to two years out. We have hedged a portion of our exposure to differentials between Intercontinental Exchange ("ICE") Brent oil ("Brent") and New York Mercantile Exchange ("NYMEX") West Texas Intermediate oil ("WTI") as well. From time to time we have entered into agreements to purchase a portion of the natural gas we require for our operations that we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

Our current hedge positions primarily consist of swap contracts and deferred premium purchased put options. In addition, we recently acquired natural gas fixed price swaps to manage our exposure to increases in natural gas prices. We enter into these transactions with respect to a portion of our projected oil production and gas purchases to provide economic hedges against the risk related to the future commodity prices. We do not enter into derivative contracts for speculative trading purposes. We did not designate any of our contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. Gains (losses) on oil hedges are classified in the revenues and other section of the statement of operations and gains (losses) on natural gas hedges are presented in the expenses and other section of the statement of operations.

As of September 30, 2018, we have hedged crude oil production at the following approximate volumes and prices: 12.8 MBbl/d at $75 in the fourth quarter of 2018, 16.5 MBbl/d at $70 in 2019, and 1.2 MBbl/d at $65 in 2020, as outlined along with our natural gas derivative contracts in the following table:

	Q4 2018	FY 2019	FY 2020
Sold Oil Calls (ICE Brent):			
Hedged volume (MBbls)	124	—	—
Weighted-average price ($/Bbl)	$ 80.00	$ —	$ —
Purchased Oil Put Options (ICE Brent):			
Hedged volume (MBbls)	—	3,385	455
Weighted-average price ($/Bbl)	$ —	$ 65.00	$ 65.00
Fixed Price Oil Swaps (ICE Brent):			
Hedged volume (MBbls)	1,058	2,640	—
Weighted-average price ($/Bbl)	$ 74.82	$ 75.40	$ —
Oil basis differential positions:			
ICE Brent-NYMEX WTI basis swaps			
Hedged volume (MBbls)	92	182.5	—
Weighted-average price ($/Bbl)	$ 1.29	$ 1.29	$ —
Fixed Price Gas Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	1,380,000	4,560,000	—
Weighted-average price ($/MMBtu)	$ 2.65	$ 2.65	$ —

We earn a premium on our sold oil calls at the time of sale. We make net settlement payments for prices above the indicated weighted-average price per barrel of Brent. If the calls expire unexercised, we make no payments.

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. The purchased put options contain deferred premiums of approximately $20 million and are reflected in the mark-to-market valuation of the derivatives on the balance sheet at September 30, 2018. The premiums will be payable in conjunction with the monthly settlements of these contracts and thus have been deferred until payments begin in 2019.

For fixed-price Brent swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent.

For oil basis swaps, we make settlement payments if the difference between Brent and WTI is greater than the indicated weighted-average price per barrel of our contracts and receive settlement payments if the difference between Brent and WTI is below the indicated weighted-average price per barrel.

For fixed-price natural gas swaps, we are the buyer so we make settlement payments for prices below the weighted-average price per MMBtu and receive settlement payments for prices above the weighted-average price per MMBtu.

Our commodity derivatives are measured at fair value using industry-standard models with various inputs including forward prices, and all are classified as Level 2 in the required fair value hierarchy for the periods presented. The following tables present the fair values (gross and net) of our outstanding derivatives as of September 30, 2018 and December 31, 2017:

	Berry Corp. (Successor)			
	September 30, 2018			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
	(in thousands)			
Liabilities				
Commodity Contracts	Current liabilities	$ (26,409)	$ —	$ (26,409)
Commodity Contracts	Non-current liabilities	(4,664)	—	(4,664)
Total derivatives		$ (31,073)	$ —	$ (31,073)

	Berry Corp. (Successor)			
	December 31, 2017			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
	(in thousands)			
Liabilities				
Commodity Contracts	Current liabilities	$ (49,949)	$ —	$ (49,949)
Commodity Contracts	Non-current liabilities	(25,332)	—	(25,332)
Total derivatives		$ (75,281)	$ —	$ (75,281)

In May 2018, we elected to terminate outstanding commodity derivative contracts for all WTI oil swaps and certain WTI/Brent basis swaps for July 2018 through December 2019 and all WTI oil sold call options for July 2018 through June 2020. Termination costs totaled approximately $127 million and were calculated in accordance with a bilateral agreement on the cost of elective termination included in these derivative contracts; the present value of the contracts using the forward price curve as of the date termination was elected. No penalties were charged as a result of the elective termination. Concurrently, Berry Corp. entered into commodity derivative contracts consisting of Brent oil swaps for July 2018 through March 2019 and Brent oil purchased put options for January 2019 through March 2020. These Brent oil swaps hedge 1.8 MMBbls in 2018 and 0.9 MMBbls in 2019 at a weighted-average price of $75.66. These Brent oil purchased put options provide a weighted-average price floor of $65.00 for 2.8 MMBbls in 2019 and 0.5 MMBbls in 2020. We effected these transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with market pricing at the time.

Note 5 - Lawsuits, Claims, Commitments and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

On May 11, 2016 our predecessor company filed the Chapter 11 Proceeding. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. On January 27, 2017, the Bankruptcy Court approved and confirmed the Plan. On February 28, 2017, the Effective Date occurred and the Plan became effective and was implemented. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at September 30, 2018 and December 31, 2017. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services. At September 30, 2018, purchase obligations of approximately $10 million included a commitment to invest at least $9 million to construct a new access road in connection with our Piceance assets or provide access to an existing road or to pay 50% of the difference between $12 million and the actual amount spent on such access road construction prior to the end of 2019. If we do not obtain extensions for the road obligation, provide access to an existing road or construct a new access road, we may trigger the payment obligation which, if we were unable to negotiate resolution, would reduce our capital available for investment. Also, as of September 30, 2018, we had entered into agreements to purchase natural gas for our operations in 2018 for approximately $4 million.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of September 30, 2018, we are not aware of material indemnity claims pending or threatened against us.

We have entered into operating lease agreements mainly for office space. Lease payments are generally expensed as part of general and administrative expenses. At September 30, 2018, future net minimum lease payments for non-cancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes and insurance and maintenance expense) totaled:

	Amount (in thousands)
2018	$ 362
2019	1,290
2020	316
2021	321
2022	326
Thereafter	229
Total minimum lease payments	$ 2,844

Note 6 - Equity

Initial Public Offering of Common Stock

In July, we completed our IPO and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY. The Company received approximately $111 million of net proceeds for the 8,695,653 shares of common stock issued for our benefit in the IPO, net of the shares sold for the benefit of the Company's stockholders. The shares sold to the public at $14.00 per share. The Company received the net proceeds from the IPO after deducting underwriting discounts and offering expenses payable by us, and the proceeds from the sale of the shares for the benefit of our stockholders. See "Use of IPO proceeds" below for additional information.

In connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock was automatically converted into 1.05 shares of our common stock or 39.6 million shares in aggregate and the right to receive a cash payment of $1.75 ("Series A Preferred Stock Conversion"). The cash payment was reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. The additional 1.9 million common shares received by the preferred stockholders in the conversion were assigned a value of $14.00 per share in the IPO. This approximate $27 million value and the $60 million conversion cash payment reduced the income available to common stockholders by approximately $87 million for the three months ended September 30, 2018.

Shares Issued and Outstanding

As of September 30, 2018, there were 81,364,933 shares of common stock issued and outstanding including 210,400 common shares outstanding as a result of awards that have vested as of September 30, 2018 under the Company's Omnibus Incentive Plan. An additional 1,396,000 unvested restricted stock units and performance restricted stock units were outstanding under the Company's Omnibus Incentive Plan as of September 30, 2018. A further 7,080,000 common shares have been reserved for issuance to the general unsecured creditor group pending resolution of disputed claims.

In March 2018, the board of directors approved a cumulative paid-in-kind dividend on the Series A Preferred Stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 per share and approximately 1,825,000 shares in total. Also in March 2018, the board approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018. In May 2018, the board of directors approved a $0.15 per share, or approximately $5.6 million cash dividend, on the Series A Preferred Stock for the quarter ended June 30, 2018. The payment was to stockholders of record as of June 7, 2018. As described above, in July 2018, all shares of our Series A

Preferred Stock, approximately 37.7 million in total, were converted to approximately 39.6 million common shares and, as a result, there were no shares of our Series A Preferred Stock outstanding following the IPO.

On August 21, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock on a pro-rata basis from the date of our IPO through September 30, 2018, which resulted in a payment of $0.09 per share in October 2018. On November 7, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the fourth quarter.

Treasury Stock Purchase

In 2018, we entered into several settlement agreements with general unsecured creditors from our bankruptcy process. As a result, we paid approximately $20 million to purchase their claims to our common stock that we have reflected as treasury stock. The Plan required that we reserve 7,080,000 shares of our common stock to settle claims of unsecured creditors (the "Unsecured Claims"). We do not yet know the final amount of shares we will issue under these provisions. When all Unsecured Claims are settled, we will be able to assign a share count to the treasury stock. See Note 2 under *"Plan of Reorganization"* and Note 11 for further discussion of the common shares set aside to settle claims.

Stock-Based Compensation

In July 2018, we became a public company and our stock began trading on the NASDAQ Global Select Market. As a result, the fair value of our common stock underlying our stock-based compensation awards granted will no longer be based on complex models using inputs and assumptions, but will be based on the price of our stock at the date of grant.

On June 27, 2018, our board of directors adopted the Berry Petroleum Corporation 2017 Omnibus Incentive Plan, as amended and restated (our "Restated Incentive Plan"). This plan constitutes an amendment and restatement of the plan (the "Prior Plan") as in effect immediately prior to the adoption of the Restated Incentive Plan. The Prior Plan constituted an amendment and restatement of the plan originally adopted as of June 15, 2017 (the "2017 Plan"). The Restated Incentive Plan provides for the grant, from time to time, at the discretion of the board of directors or a committee thereof, of stock options, stock appreciation rights ("SARs"), restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards and substitute awards. The maximum number of shares of common stock that may be issued pursuant to an award under the Restated Incentive Plan is 10,000,000 inclusive of the number of shares of common stock previously issued pursuant to awards granted under the Prior Plan or the 2017 Plan. The maximum number of shares remaining that may be issued is approximately 8.4 million as of September 30, 2018.

Included in lease operating expenses and general and administrative expenses is stock-based compensation expense of $0.1 million and $1.1 million, respectively, for the three months ended September 30, 2018, and $0.1 million and $3.4 million, respectively, for the nine months ended September 30, 2018. For the three and nine months ended September 30, 2017, including the successor and predecessor periods, stock compensation expense included in lease operating expenses and general and administrative expenses was none and $0.9 million, respectively. For the nine months ended September 30, 2018, stock-based compensation had an income tax benefit of approximately $0.6 million.

The table below summarizes the activity relating to restricted stock units ("RSUs") issued under the 2017 Plan during the nine months ended September 30, 2018. The RSUs vest ratably over three years. Unrecognized compensation cost associated with the RSUs at September 30, 2018 is approximately $6.2 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares		Weighted-average Grant Date Fair Value
	(shares in thousands)		
December 31, 2017	683	$	10.12
Granted	217	$	11.81
Vested	(210)	$	10.12
Forfeited	(32)	$	10.35
September 30, 2018	658	$	10.67

The table below summarizes the activity relating to the performance-based restricted stock units ("PRSUs") issued under the 2017 Plan during the nine months ended September 30, 2018. The PRSUs vest if the Company's stock price reaches certain levels over defined periods of time. Unrecognized compensation cost associated with the PRSUs at September 30, 2018 is approximately $3.4 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares		Weighted-average Grant Date Fair Value
	(shares in thousands)		
December 31, 2017	622	$	7.09
Granted	132	$	7.65
Vested	—	$	—
Forfeited	(16)	$	7.25
September 30, 2018	738	$	7.19

In October 2018, approximately 454,000 PRSUs under the Restated Incentive Plan vested.

Use of IPO Proceeds

Of the approximately $111 million of net proceeds received by us in the IPO, we used approximately $105 million to repay borrowings under our RBL Facility. This included the $60 million we borrowed on the RBL Facility to make the payment due to the holders of our Series A Preferred Stock in connection with the conversion of preferred stock to common stock. We used the remainder for general corporate purposes.

In connection with the IPO, on July 17, 2018, the Company entered into stock purchase agreements with certain funds affiliated with Oaktree Capital Management and Benefit Street Partners, pursuant to which we purchased an aggregate of 410,229 and 1,391,967 shares of our common stock, respectively, or 1,802,196 in total. We simultaneously received $24 million for selling 1,802,196 shares and paid $24 million to purchase 1,802,196 shares under the stock purchase agreements. We purchased the shares immediately following the closing of the IPO and retired and returned them to the status of authorized but unissued shares.

The selling shareholders also directly sold an additional 2,545,630 shares at a price of $14.00 per share for which we did not receive any proceeds.

Note 7 - Income Taxes

Prior to the Effective Date, Berry LLC was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, Berry LLC was not a taxable entity, it did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of Berry LLC. Upon emergence from bankruptcy, Berry Corp. acquired the assets of Berry LLC in a taxable asset acquisition as part of the restructuring. Consequently, we are now taxed as a corporation and have no net operating loss carryforwards for the periods prior to February 28, 2017.

On December 22, 2017, the U.S. Tax Cuts and Jobs Act (the “Act”) made significant changes to the Internal Revenue Code of 1986, including lowering the maximum federal corporate rate from 35% to 21% and imposing limitations on the use of net operating losses arising in taxable years ending after December 31, 2017. This was the key contributor to the decrease in our effective rate from 40% in the 2017 Successor periods to 17% in each of the three and nine months ended September 30, 2018. We anticipate earnings for fiscal year 2018, in part due to the termination and resetting of our hedge positions in May 2018. These earnings consequently allow for the release of our valuation allowance, described below, resulting in an effective tax rate less than the maximum federal and applicable state tax rate for the nine months ended September 30, 2018. There were no current income taxes during the nine months ended September 30, 2018.

Our accounting for the U.S. Tax Reform Act is incomplete. As noted at year-end, however, we were able to reasonably estimate certain effects and, therefore, recorded provisional adjustments to income tax expense for the revaluation of deferred tax assets and liabilities from 35% to 21% associated with the reduction in the U.S. corporate income tax rate, and for a valuation allowance on certain deferred tax assets impacted by the Act. We have not revised any of the 2017 provisional estimates. Any subsequent adjustments to these amounts will be recorded to income tax expense in the fourth quarter of 2018 after analysis of the filed 2017 income tax return is complete.

Note 8 - Supplemental Disclosures to the Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Cash Flows

Other current assets reported on the condensed consolidated balance sheets included the following:

	Berry Corp. (Successor)	
	September 30, 2018	December 31, 2017
	(in thousands)	
Prepaid expenses	$ 4,945	$ 6,901
Oil inventories, materials and supplies	7,060	5,938
Other	1,228	1,227
Total	$ 13,233	$ 14,066

The major classes of inventory were not material and therefore not stated separately. Other non-current assets at September 30, 2018 and December 31, 2017, included approximately $17 million and $20 million of deferred financing costs, net of amortization, respectively.

BERRY PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Accounts payable and accrued expenses on the condensed consolidated balance sheets included the following:

	Berry Corp. (Successor)	
	September 30, 2018	December 31, 2017
	(in thousands)	
Accounts payable-trade	$ 10,483	$ 15,469
Accrued expenses	54,969	34,359
Royalties payable	26,004	25,793
Greenhouse gas liability	4,364	10,446
Taxes other than income tax liability	11,021	8,437
Accrued interest	3,529	—
Dividends payable	7,431	—
Other	—	3,373
Total	$ 117,801	$ 97,877

Other non-current liabilities at September 30, 2018 included approximately $12 million of greenhouse gas liability.

Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below:

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)		
Supplemental Disclosures of Significant Non-Cash Investing Activities:			
(Decrease) increase in accrued liabilities related to purchases of property and equipment	$ 8,832	$ 1,008	$ 2,249
Supplemental Disclosures of Cash Payments/(Receipts):			
Interest	$ 19,199	$ 9,987	$ 8,057
Income taxes	$ —	$ 1,994	$ —
Reorganization items, net	$ 1,007	$ (375)	$ 11,838

The following table provides a reconciliation of Cash, Cash Equivalents and Restricted Cash as reported in the Consolidated Statements of Cash Flows to the line items within the Consolidated Balance Sheets:

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine months ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)		
Beginning of Period			
Cash and cash equivalents	$ 33,905	$ 32,049	$ 30,483
Restricted cash	34,833	52,860	197,793
Restricted cash in other noncurrent assets	—	125	128
Cash, cash equivalents and restricted cash	$ 68,738	$ 85,034	$ 228,404
Ending of Period			
Cash and cash equivalents	$ 23,856	$ 2,927	$ 32,049
Restricted cash	57	35,000	52,860
Restricted cash in other noncurrent assets	—	—	125
Cash, cash equivalents and restricted cash	$ 23,913	$ 37,927	$ 85,034

Restricted cash is associated with cash reserved to settle claims with general unsecured creditors resulting from implementation of the Plan. Cash and cash equivalents consists primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value.

Note 9 - Certain Relationships and Related Party Transactions

In connection with our emergence from bankruptcy, we entered into agreements with certain of our affiliates and with parties who received shares of our common stock and Series A Preferred Stock in exchange for their claims. See Note 6 - Equity for further details.

Transition Services and Separation Agreement (“TSSA”)

On the Effective Date, Berry LLC entered into the TSSA with Linn Energy and certain of its subsidiaries to facilitate the separation of Berry LLC’s operations from Linn Energy’s operations. Under the TSSA, Berry LLC reimbursed Linn Energy for third-party out-of-pocket costs and expenses actually incurred by Linn Energy in connection with providing certain transition services. Additionally, Berry LLC paid to Linn Energy a management fee equal to $6 million per month, prorated for partial months, during the period from the Effective Date through the last day of the second full calendar month after the Effective Date (the “Transition Period”) and $2.7 million per month, prorated for partial months, from the first day following the Transition Period through the last day of the second full calendar month thereafter (the “Accounting Period”). During the Accounting Period, the scope of the transition services was reduced to specified accounting and administrative services. The Transition Period under the TSSA ended April 30, 2017, and the Accounting Period ended June 30, 2017. For the seven months ended September 30, 2017, we incurred management fee expenses of approximately $17 million under the TSSA. Since the agreement commenced on the Effective Date, no expenses were incurred for the period ended February 28, 2017.

Note 10 - Acquisitions and Divestitures

Chevron North Midway-Sunset Acquisition

In April 2018, we acquired two leases from a third party on an aggregate of 214 acres and a lease option on 490 acres (the "Chevron North Midway-Sunset Acquisition") of land owned by Chevron U.S.A. in the north Midway-Sunset field immediately adjacent to assets we currently operate. We assumed a drilling commitment of approximately $34.5 million to drill 115 wells on or before April 1, 2020. We have not drilled any of these wells as of September 30, 2018. We extended the commitment to April 1, 2022. We would assume an additional 40 well drilling commitment if we exercise our option on the 490 acres. We paid no other consideration for the acquisition. Our drilling commitment will be tolled for a month for each consecutive 30-day period for which the posted price of WTI is less than $45 per barrel. This transaction is consistent with our business strategy to investigate areas beyond our known productive areas.

Disposition of East Texas Properties

On October 17, 2018, we signed an agreement to sell our non-core oil and gas properties and related assets located in the East Texas Basin for approximately $7 million. Production comprised approximately 0.7 MBoe per day of natural gas in the third quarter of 2018. We anticipate closing this sale in the fourth quarter of 2018.

Note 11 - Earnings Per Share

The Predecessor was organized as a limited liability company and, as such, did not issue any stock. Accordingly, we have not presented earnings per share calculations for the predecessor company periods.

We calculate basic earnings (loss) per share by dividing net income (loss) available to common stockholders by the weighted-average number of common shares outstanding during each period. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, such as those shares contemplated by the Plan, are considered common shares outstanding and are included in the computation of net income (loss) per share. Accordingly, the 40 million shares of common stock contemplated by the Plan, without regard to actual issuance dates, were included in the computation of net income (loss) per share for the three and nine months ended September 30, 2018, and the three and seven months ended September 30, 2017. The Plan required that we reserve 7,080,000 shares of our common stock to settle claims of unsecured creditors. The final amount of shares we will issue under these provisions cannot be known until all claims are settled, adjustments have been made based on the stock to be received by Unsecured Claims including those of holders of Unsecured Notes. However, while we do not yet know the final amount of shares that we will issue to third parties, we entered into agreements in 2018 that have materially reduced that number. The 40 million shares above will be reduced to the extent we issue fewer than 7,080,000 shares.

The Series A Preferred Stock was not a participating security, therefore, we calculated diluted EPS using the “if-converted" method under which the preferred dividends are added back to the numerator and the convertible preferred stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock or RSUs were included in the diluted EPS calculation for the three and nine months ended September 30, 2018, nor the three months ended September 30, 2017 as their effect was anti-dilutive under the “if-converted” method. No PRSU's were included in the EPS calculations for any of the periods presented due to their contingent nature.

In July 2018, all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO of our common stock (see Note 6). The conversion was characterized as an induced conversion that required a deduction in our EPS calculation, from net income, of approximately $87 million in determining income available to common stockholders. This deduction represents the excess of fair value of the total consideration given to preferred stockholders in the transaction over the fair value of the common stock issuable under the original conversion terms. Included in the $87 million is a $60 million cash payment and approximately $27 million of value from the 1.9 million additional common shares received by preferred stockholders as a result of the automatic conversion that occurred in conjunction with our IPO.

BERRY PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

	Berry Corp. (Successor)				Berry LLC (Predecessor)
	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands except per share amounts)				
Basic EPS calculation					
Net income (loss)	$ 36,985	$ (9,684)	$ 15,334	13,812	n/a
less: Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(97,942)	(12,681)	n/a
Net income (loss) available to common stockholders	$ (49,657)	$ (15,169)	$ (82,608)	$ 1,131	n/a
Weighted-average shares of common stock outstanding	68,131	32,920	44,820	32,920	n/a
Shares of common stock distributable to holders of Unsecured Claims	7,080	7,080	7,080	7,080	n/a
Weighted-average common shares outstanding-basic	75,211	40,000	51,900	40,000	n/a
Basic Earnings (loss) per share [(2)]	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a
Diluted EPS calculation					
Net income (loss)	$ 36,985	$ (9,684)	$ 15,334	$ 13,812	n/a
less: Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(97,942)	(12,681)	n/a
Net income (loss) available to common stockholders	$ (49,657)	$ (15,169)	$ (82,608)	$ 1,131	n/a
Weighted-average shares of common stock outstanding	68,131	32,920	44,820	32,920	n/a
Shares of common stock distributable to holders of Unsecured Claims	7,080	7,080	7,080	7,080	n/a
Weighted-average common shares outstanding-basic	75,211	40,000	51,900	40,000	n/a
Dilutive effect of potentially dilutive securities [(1)]	—	—	—	602	n/a
Weighted-average common shares outstanding-diluted	75,211	40,000	51,900	40,602	n/a
Diluted Earnings (loss) per share [(2)]	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a

____

(1) No potentially dilutive securities were included in computing earnings (loss) per share for the three and nine months ended September 30, 2018 and for the three months ended September 30, 2017 because the effect of inclusion would have been anti-dilutive.
(2) Per share amounts are stated net of tax.

ANNEX A

Report as of December 31, 2017

of DeGolyer and MacNaughton

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

January 31, 2018

Berry Petroleum Company, LLC
5201 Truxton Avenue, Suite 100
Bakersfield, CA 93309

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2017, of certain properties in which Berry Petroleum Company, LLC (Berry) has represented that it owns an interest. This evaluation was completed on January 31, 2018. Berry has represented that these properties account for 100 percent of Berry's net proved reserves as of December 31, 2017. The properties are located in California, Colorado, Texas, and Utah. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Berry.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2017. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Berry after deducting all interests owned by others.

Estimates of oil, condensate, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Berry personnel, from Berry files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Berry with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

METHODOLOGY AND PROCEDURES

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Berry, and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP). Structure maps were utilized to delineate each reservoir, and isopach maps were utilized to estimate the reservoir volume. Electric logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the fluid and rock properties, and the production histories. An analysis of the reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves. Most of the properties in California evaluated herein are produced using thermal recovery methods involving either cyclic steam injection or continuous steamflood operation. Therefore, steam-oil ratios and steam volumes were analyzed and projected and were used in the estimation of reserves when applicable.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production based on existing economic conditions.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Gas reserves estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel use and shrinkage resulting from field separation and processing. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit and at the pressure base of the state in which the reserves are located. Gas reserves included herein are expressed in thousands of cubic feet (Mcf). Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements. Oil, condensate, and NGL reserves included in this report are expressed in barrels (bbl) representing 42 United States gallons per barrel. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

DEFINITION OF RESERVES

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

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

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

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

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

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

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

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

Developed oil and gas reserves—Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The development status shown herein represents the status applicable on December 31, 2017. In the preparation of this study, data available from wells drilled on the evaluated properties through December 31, 2017, were used in estimating gross ultimate recovery. When applicable, gross production estimated through December 31, 2017, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves. In some fields this required that the production rates be estimated for up to 6 months, since production data from certain properties were available only through June 2017.

PRIMARY ECONOMIC ASSUMPTIONS

Values of proved reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs, from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth of future net revenue is calculated by discounting the future net revenue at the arbitrary rate of 10 percent per year compounded annually over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The assumptions used for estimating future prices and expenses are as follows:

Oil, Condensate, and NGL Prices

Oil, condensate, and NGL price differentials for each property were provided by Berry. The prices were calculated using these differentials to a posted Europe Brent oil price of $54.42 per barrel and were held constant for the lives of the properties. The Brent oil price of $54.42 per barrel is the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate and $28.25 per barrel of NGL.

Gas Prices

Gas price differentials for each property were provided by Berry. The prices were calculated using these differentials to a Henry Hub price of $2.98 per million British thermal units (MMBtu) and were held constant for the lives of the properties. The Henry Hub gas price of $2.98 per MMBtu is the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to December 31, 2017. British thermal unit factors were provided by Berry and used to convert prices from dollars per MMBtu to dollars per thousand cubic feet ($/Mcf). The volume-weighted average price over the lives of the properties was $2.935 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for the state in which the property is located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Berry that were based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Berry and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2017 values, provided by Berry, and were not adjusted for inflation. Abandonment costs, net of salvage where applicable, were provided by Berry for all properties and include all reclamation and restoration costs associated with abandonment. The abandonment costs were provided by Berry in aggregate at the district level except for wells drilled in 2017 and for proposed undeveloped wells, where they are shown with the individual property.

The estimates of Berry's net proved reserves attributable to the reviewed properties were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2017			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved				
Developed Producing	62,615	1,263	99,997	80,544
Developed Non-Producing	5,875	8	387	5,947
Total Proved Developed	**68,490**	**1,271**	**100,384**	**86,491**
Undeveloped	32,106	0	136,720	54,893
Total Proved	**100,596**	**1,271**	**237,104**	**141,384**

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue and costs attributable to the production and sale of Berry's net proved reserves, as of December 31, 2017, of the properties reviewed under the aforementioned assumptions concerning future prices and costs are summarized in thousands of dollars (M$) as follows:

	Proved Developed Producing (M$)	Proved Developed Non-Producing (M$)	Total Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Future Gross Revenue	3,268,939	292,456	3,561,395	2,019,053	5,580,448
Production Taxes	66,914	3,316	70,230	13,186	83,416
Ad Valorem Taxes	85,610	9,520	95,130	62,336	157,466
Operating Expenses	1,692,989	96,657	1,789,646	696,019	2,484,665
Capital Costs	49,872	9,971	59,843	487,888	547,731
Abandonment Costs	92,700	286	92,986	37,596	130,582
Future Net Revenue	1,280,854	173,706	1,454,560	722,028	2,176,588
Present Worth at 10 Percent	762,313	89,447	851,760	262,399	1,114,159

Note: Future income tax expenses have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2017, estimated reserves.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, Extractive Industries—Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the Financial Accounting Standards Board and Rules 4—10(a) (1)—(32) of Regulation S—X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S—K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Berry. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Berry. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]

CERTIFICATE OF QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Berry dated January 31, 2018, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 33 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves

Gregory K. Graves, P.E.

[SEAL] Senior Vice President

DeGolyer and MacNaughton

ADDENDUM

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244
June 28, 2018

Berry Petroleum Company, LLC
5201 Truxton Avenue, Suite 100
Bakersfield, CA 93309

Ladies and Gentlemen:

Pursuant to your request, we have prepared this letter to serve as an addendum, as of December 31, 2017, to our report of third party dated January 31, 2018, containing our opinion of the proved reserves and revenue, as of December 31, 2017, of Berry Petroleum Company, LLC (the ROTP) to present additional information as an extension of the ROTP. This letter was completed on June 28, 2018. The purpose of this letter is to prepare a Price Sensitivity Case on the properties evaluated in the ROTP. This letter is subject to the terms, definitions, assumptions, explanations, conclusions, and conditions described in the ROTP. However, the future price forecast for this Price Sensitivity Case does not meet the guidelines established by the United States Securities and Exchange Commission (SEC); therefore, the reserves and revenue presented herein should not be used to meet the requirements of the SEC.

Oil, condensate, natural gas liquids (NGL), and gas prices in the Price Sensitivity Case differ from the fixed prices in the ROTP. The price forecast for this sensitivity was provided by Berry and has been represented by Berry as reflective of the futures market price of Brent Oil on May 31, 2018, and the futures market price of Henry Hub Gas on May 31, 2018.

The price differentials used herein for each product differ from those used in the ROTP. The price differentials used for this sensitivity were provided by Berry and were represented by Berry as reflective of the price differentials calculated for the properties evaluated in the ROTP during the month of May 2018.

For this letter, the as-of date of this Price Sensitivity Case, December 31, 2017, is the same as that used for the ROTP, and the prices in the following table were applied to the production forecast estimates previously prepared for the properties evaluated in the ROTP. However, the production forecast estimates in this letter were allowed to run until a new economic limit, based on the respective Price Sensitivity Case, was reached. As such, the projections of estimated proved production and revenue present alternative outcomes to the projections of estimated proved production and revenue presented in the ROTP. Except as noted above concerning the price differentials, all other economic components of the evaluation for the Price Sensitivity Case are the same as contained in the ROTP. Even though this Price Sensitivity Case was completed on June 28, 2018, no additional data beyond that used for the ROTP were incorporated herein. A detailed explanation of these economic assumptions is contained under the Primary Economic Assumptions heading of the ROTP.

DeGolyer and MacNaughton

The Price Sensitivity Case oil, condensate, NGL, and gas prices used in this letter are as follows, expressed in dollars per barrel ($/bbl) and dollars per million British thermal units ($/MMBtu):

Year	Oil, Condensate, and NGL Price ($/bbl)	Gas Price ($/MMBtu)
2018	74.59	2.94
2019	72.98	2.75
2020	69.15	2.68
2021 and thereafter	66.49	2.66

The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.943 per thousand cubic feet of gas.

The estimates of Berry's net proved reserves attributable to the properties evaluated under the Price Sensitivity Case described herein are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Price Sensitivity Case Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2017			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved				
Developed Producing	64,277	1,117	66,937	76,551
Developed Non-Producing	6,013	8	392	6,086
Total Proved Developed	**70,290**	**1,125**	**67,329**	**82,637**
Undeveloped	32,102	0	0	32,102
Total Proved	**102,392**	**1,125**	**67,329**	**114,739**

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue and costs attributable to the production and sale of Berry's net proved reserves, as of December 31, 2017, of the properties reviewed under the Price Sensitivity Case described herein are summarized in thousands of dollars (M$) as follows:

	Proved Developed Producing (M$)	Proved Developed Non-Producing (M$)	Total Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Future Gross Revenue	4,028,481	379,021	4,407,502	2,059,708	6,467,210
Production Taxes	65,737	3,514	69,251	11,621	80,872
Ad Valorem Taxes	106,156	12,337	118,493	64,163	182,656
Operating Expenses	1,666,065	98,698	1,764,763	525,438	2,290,201
Capital Costs	49,872	9,971	59,843	347,654	407,497
Abandonment Costs	92,700	286	92,986	34,936	127,922
Future Net Revenue	2,047,951	254,215	2,302,166	1,075,896	3,378,062
Present Worth at 10 Percent	1,205,255	135,557	1,340,812	520,804	1,861,616

Note: Future income tax expenses have not been taken into account in the preparation of these estimates.

DeGolyer and MacNaughton

Apart from the main body of the ROTP, this letter may be subject to misunderstanding or misinterpretation. The ROTP should be relied upon solely as the source of authoritative final results.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]

ANNEX B

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this prospectus, which are commonly used in the oil and natural gas industry:

"*API*" gravity means the relative density, expressed in degrees, of petroleum liquids based on a specific gravity scale developed by the American Petroleum Institute.

"*basin*" means a large area with a relatively thick accumulation of sedimentary rocks.

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

"*Bcf*" means one billion cubic feet, which is a unit of measurement of volume for natural gas.

"*Boe*" means barrel of oil equivalent, determined using the ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas.

"*Boe/d*" means Boe per day.

"*Brent*" means the reference price paid in U.S. dollars for a barrel of light sweet crude oil produced from the Brent field in the UK sector of the North Sea.

"*Btu*" means one British thermal unit—a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"*Completion*" means the installation of permanent equipment for the production of oil or natural gas.

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

"*Development drilling*" or "*Development well*" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"*Diatomite*" means a sedimentary rock composed primarily of siliceous, diatom shells.

"*Differential*" means 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.

"*Downspacing*" means additional wells drilled between known producing wells to better develop the reservoir.

"*Enhanced oil recovery*" or "*EOR*" means a technique for increasing the amount of oil that can be extracted from a field.

"*Estimated ultimate recovery*" or "*EUR*" means the sum of reserves remaining as of a given date and cumulative production as of that date. As used in this prospectus, EUR includes only proved reserves attributable to each location in our reserve report as of December 31, 2017 and is based on our reserve estimates. EUR is shown on a combined basis for oil and natural gas.

"*Exploration activities*" means the initial phase of oil and natural gas operations that includes the generation of a prospect or play and the drilling of an exploration well.

“*Field*” means 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.

“*Formation*” means a layer of rock which has distinct characteristics that differ from those of nearby rock.

“*Fracturing*” means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks by connecting pores together.

“*Gas*” or “*Natural gas*” means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

“*Gross Acres*” or “*Gross Wells*” means the total acres or wells, as the case may be, in which we have a working interest.

“*Held by production*” means acreage covered by a mineral lease that perpetuates a company’s right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.

“*Henry Hub*” is a distribution hub on the natural gas pipeline system in Erath, Louisiana.

“*Hydraulic fracturing*” means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability.

“*Horizontal drilling*” means a wellbore that is drilled laterally.

“*ICE*” means Intercontinental Exchange.

“*Infill drilling*” means drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.

“*Injection Well*” means a well in which water, gas or steam is injected, the primary objective typically being to maintain reservoir pressure and/or improve hydrocarbon recovery.

“*IOR*” means improved oil recovery.

“*Leases*” means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

“*MBbl*” means one thousand barrels of oil, condensate or NGLs.

“*MBbl/d*” means MBbl per day.

“*MBoe*” means one thousand barrels of oil equivalent.

“*MBoe/d*” means MBoe per day.

“*Mcf*” means one thousand cubic feet, which is a unit of measurement of volume for natural gas.

“*MMBbl*” means one million barrels of oil, condensate or NGLs.

“*MMBoe*” means one million barrels of oil equivalent.

"*MMBtu*" means one million Btus.

"*MMcf*" means one million cubic feet, which is a unit of measurement of volume for natural gas.

"*MMcf/d*" means MMcf per day.

"*MW*" means megawatt.

"*Net Acres*" or "*Net Wells*" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"*Net revenue interest*" means all of the working interests, less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"*NGL*" means natural gas liquids, which are the hydrocarbon liquids contained within natural gas.

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

"*Operator*" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"*PDNP*" is an abbreviation for proved developed non-producing.

"*PDP*" is an abbreviation for proved developed producing.

"*Permeability*" means the ability, or measurement of a rock's ability, to transmit fluids.

"*Play*" means a regionally distributed oil and natural gas accumulation. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations.

"*Porosity*" means the total pore volume per unit volume of rock.

"*PPA*" is an abbreviation for power purchase agreement.

"*Production costs*" means costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).

"*Productive well*" means a well that is producing oil, natural gas or NGLs or that is capable of production.

"*Proppant*" means sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.

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

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

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

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

"*Proved undeveloped drilling location*" means a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*" means proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"*PV-10*" is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC—prescribed pricing assumptions for the period. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the company on a comparative basis to other companies and from period to period.

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

"*Reasonable certainty*" means a high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

"*Recompletion*" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

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

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

"*Royalty*" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"*Royalty interest*" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"*SEC Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules based on the unweighted arithmetic average of oil and natural gas prices as of the first day of each of the 12 months ended on the given date.

"*Seismic Data*" means data produced by an exploration method of sending energy waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

"*Spacing*" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Steamflood*" means cyclic or continuous steam injection.

"*Standardized measure*" means discounted future net cash flows estimated by applying year-end prices to the estimated future production of proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Strip Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules with the exception of pricing that is based on average annual forward-month ICE (Brent) oil and NYMEX Henry Hub natural gas contract pricing in effect on a given date to reflect the market expectations as of that date.

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

"*Unit*" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Unproved reserves*" means reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

"*Wellbore*" means the hole drilled by the bit that is equipped for natural resource production on a completed well. Also called well or borehole.

"*Working interest*" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"*Workover*" means maintenance on a producing well to restore or increase production.

"*WTI*" means West Texas Intermediate.

61,420,234 Shares

Berry Petroleum Corporation

Common Stock