Berry Petroleum Company, LLC
Form 10-K
March 28, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
.. TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to _______________
Commission file number: 1-9735
BERRY PETROLEUM COMPANY, LLC
(Successor in interest to Berry Petroleum Company)
(Exact name of registrant as specified in its charter)

Delaware	77-0079387
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

600 Travis, Suite 5100
Houston, Texas 77002
(Address of principal executive offices, including zip code)
Registrant’s telephone number, including area code:
(281) 840-4000
Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES o NO ý
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ý NO o
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES o NO ý
Pursuant to the terms of its senior note indentures, the registrant is a voluntary filer of reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934, and has filed all such reports as required by its senior note indentures during the preceding 12 months.
The registrant meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K as it is an indirect wholly owned subsidiary of Linn Energy, LLC, which is a reporting company under the Securities Exchange Act of 1934 and which has filed with the SEC all materials required to be filed pursuant to Section 13, 14 or 15(d) thereof, and the registrant is therefore filing this Form 10-K with a reduced disclosure format.
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ý NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer o Accelerated filer o Non-accelerated filer ý Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO ý
On December 16, 2013, the registrant was acquired (see Note 1 of Notes to Financial Statements), as a result of which 100% of its membership interest is currently held by a single member and the registrant deregistered its equity under the Securities Exchange Act of 1934.
Documents Incorporated by Reference:
None

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Glossary of Terms

As commonly used in the oil and natural gas industry and as used in this Annual Report on Form 10-K, the following terms have the following meanings:

Basin. A large area with a relatively thick accumulation of sedimentary rocks.

Bbl. One stock tank barrel or 42 United States gallons liquid volume.

Bbls/d. Bbls per day.

Bcf. One billion cubic feet.

BOE. 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. BOE per day.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 degrees to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive.

Diatomite. A sedimentary rock composed primarily of siliceous, diatom shells.

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

Enhanced oil recovery. A technique for increasing the amount of oil that can be extracted from a field.

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

Formation. A stratum of rock that is recognizable from adjacent strata consisting primarily of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

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

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

MBbls/d. MBbls per day.

MBOE. One thousand barrels of oil equivalent.

MBOE/d. MBOE per day.

Mcf. One thousand cubic feet.

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

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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MMcf/d. MMcf per day.
Mwh. One thousands kilowatts of electricity used continuously for one hour.
Mwh/d. Mwh per day.
Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.
NGL. Natural gas liquids, which are the hydrocarbon liquids contained within natural gas.
Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.
Proved developed reserves. Reserves that can be expected to be recovered 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 through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Proved reserves. Reserves that 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. 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. 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. 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 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.
Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.
Reservoir. A porous and permeable underground formation containing a natural accumulation of economically productive natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reserves.
Royalty interest. An interest that entitles the owner of such interest to a share of the mineral production from a property or to a share of the proceeds there from. It does not contain the rights and obligations of operating the property and normally does not bear any of the costs of exploration, development and operation of the property.
Spacing. The number of wells which conservation laws allow to be drilled on a given area of land.
Standardized measure of discounted future net cash flows. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.

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Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, natural gas and NGL regardless of whether such acreage contains proved reserves.
Unproved reserves. 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.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover. Maintenance on a producing well to restore or increase production.

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Part I

Item 1. Business

This Annual Report on Form 10-K contains forward-looking statements based on expectations, estimates and assumptions as of the date of this filing. These statements by their nature are subject to a number of risks and uncertainties. Actual results may differ materially from those discussed in the forward-looking statements. For more information, see "Cautionary Statement Regarding Forward-Looking Statements" included at the end of this Item 1. "Business" and see also Item 1A. "Risk Factors."

References

The reference to a "Note" herein refers to the accompanying Notes to Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Overview

Berry Petroleum Company, LLC ("Berry" or the "Company") was formed as a Delaware limited liability company on December 16, 2013, and is an indirect wholly owned subsidiary of Linn Energy, LLC ("LINN Energy") engaged in the production and development of oil and natural gas. The Company's predecessor, Berry Petroleum Company, was publicly traded from 1987 until December 2013. On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between LINN Energy, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and LINN Energy, under which LinnCo contributed Berry to LINN Energy in exchange for LINN Energy units (see Note 2). Linn Acquisition Company, LLC, a direct subsidiary of LINN Energy, is currently the Company's sole member.

The Company's properties are located in the United States ("U.S."), in California (San Joaquin Valley and Los Angeles basins), Kansas and the Oklahoma Panhandle (Hugoton Basin), Utah (Uinta Basin), Colorado (Piceance Basin) and east Texas. In August and November of 2014, the Company divested all of its properties located in the Permian Basin.

Proved reserves at December 31, 2015, were approximately 175 MMBOE, of which approximately 53% were oil, 37% were natural gas and 10% were natural gas liquids ("NGL"). All proved reserves were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $995 million. At December 31, 2015, the Company operated 5,910 or approximately 96% of its 6,125 gross productive wells and had an average proved reserve-life index of approximately 10 years, based on the December 31, 2015, reserve report and year-end 2015 production.

Strategy

The Company's business strategy is to add value by efficiently increasing production, reserves and cash flow. The Company's strategy is based on the following:

- pursuing the development of projects that the Company believes will generate attractive rates of return;
- maintaining a balanced portfolio of long-lived oil and natural gas properties that provide stable cash flows;
- maximizing production from the Company's base assets; and
- maintaining a strong financial position by investing capital in a disciplined manner.

Business Strengths

The Company believes that the following strengths allow it to successfully execute its business strategy:

Low-Risk Multi-Year Drilling Inventory in Established Oil and Natural Gas Plays

The Company has a significant number of drilling locations in established oil and natural gas plays that possess low geologic risk, leading to relatively predictable drilling results. The Company's complementary mix of primary development locations as well as heavy oil thermal projects provide the financial flexibility to respond to commodity price and localized operating environments.

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Balanced High-Quality Asset Portfolio
Since 2002, the Company has grown its asset base and diversified its portfolio primarily through acquisitions in the Uinta Basin and Hugoton Basin. The Company’s portfolio provides the flexibility to allocate capital among a diverse set of assets.
Long-Lived Proved Reserves with Stable Production Characteristics
The Company’s properties generally have long reserve lives and reasonably stable and predictable well production characteristics. The Company’s ratio of proved reserves to production was approximately 12 years as of December 31, 2015.
Operational Control and Financial Flexibility
The Company exercises operating control over approximately 96% of its assets. The Company generally prefers to retain operating control over its properties, allowing it to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production and allocation of the Company’s capital costs. In addition, the timing of most of the Company’s capital expenditures is discretionary, which allows LINN Energy a significant degree of flexibility to adjust the size of the Company’s capital program. Since December 2013, the Company has financed its drilling and development program primarily through internally generated net cash provided by operating activities and funding from LINN Energy.
Experienced Management and Operational Teams
The Company’s core team of technical staff and operating managers has broad industry experience, including experience in heavy oil thermal recovery operations and unconventional reservoir development and completion. The Company continues to utilize technologies and steam practices that it believes will allow the Company to improve the ultimate recovery of oil from its properties in California.
Recent Developments
See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for details about the Company’s going concern uncertainty.
Financing Activities
During the year ended December 31, 2015, the Company repurchased at a discount, on the open market and through a privately negotiated transaction, approximately $65 million of its outstanding senior notes.
In October 2015, the Company entered into an amendment to its Second Amended and Restated Credit Agreement (“Credit Facility”). The spring 2015 semi-annual borrowing base redetermination of the Company’s Credit Facility was completed in May 2015, and as a result of lower commodity prices, the borrowing base under the Credit Facility decreased from $1.4 billion to $1.2 billion, including $250 million posted as restricted cash (discussed below). The fall 2015 semi-annual redetermination was completed in October 2015 and the borrowing base under the Credit Facility decreased from $1.2 billion to $900 million, including the $250 million of restricted cash. In connection with the reduction in Berry’s borrowing base in October 2015, Berry repaid $300 million of borrowings outstanding under the Credit Facility. Continued low commodity prices, reductions in the Company’s capital budget and the resulting reserve write-downs are expected to adversely impact future redeterminations.
In connection with the reduction in Berry’s borrowing base in May 2015, LINN Energy contributed $250 million to Berry to post as restricted cash with Berry’s lenders. As directed by LINN Energy, the $250 million was deposited on Berry’s behalf in a security account with the administrative agent subject to a security control agreement. Berry’s ability to withdraw funds from this account is subject to a concurrent reduction of the borrowing base under the Credit Facility or lender’s consent in connection with a redetermination of such borrowing base. The $250 million may be used to satisfy obligations under the Credit Facility or, subject to restrictions in the indentures governing Berry’s senior notes, may be returned to LINN Energy in the future.
See Note 3 for additional details about the Company’s debt.

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Commodity Derivatives
During the year ended December 31, 2015, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for May 2015 through December 2016 to hedge exposure to differentials in certain producing areas and oil swaps for April 2015 through December 2015. In addition, the Company entered into natural gas basis swaps for May 2015 through December 2016 to hedge exposure to the differential in California, where it consumes natural gas in its heavy oil development operations.

Properties
The Company currently has five operating areas in the U.S.: California, Hugoton Basin, Uinta Basin, Piceance Basin and East Texas.

California
The Company's California operating area consists of properties located in the Midway-Sunset, McKittrick, Poso Creek and South Belridge fields in the San Joaquin Valley Basin as well as the Placerita Field in the Los Angeles Basin. The properties in this operating area produce using thermal enhanced oil recovery methods at depths ranging from 800 feet to 2,000 feet. California proved reserves represented approximately 50% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This operating area produced 25.8 MBOE/d or 53% of the Company's 2015 average daily production.

Hugoton Basin
The Company's Hugoton Basin properties are located in southwest Kansas and the Oklahoma Panhandle and primarily produce from the Council Grove and Chase formations at depths ranging from 2,200 feet to 3,100 feet. Hugoton Basin proved reserves represented approximately 38% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This operating area produced 9.9 MBOE/d or 21% of the Company's 2015 average daily production.

Uinta Basin
The Company's Uinta Basin properties target the Green River and Wasatch formations that produce both oil and natural gas at depths ranging from 5,000 feet to 7,500 feet. To more efficiently transport its natural gas in the Uinta Basin to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 750 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. The Company also owns the Brundage Canyon natural gas processing plant with capacity of approximately 30 MMcf/d. Uinta Basin proved reserves represented approximately 7% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This operating area produced 8.0 MBOE/d or 17% of the Company's 2015 average daily production.

Piceance Basin
The Company's Piceance Basin properties target the Williams Fork section of the Mesaverde formation and produce at depths ranging from 7,500 feet to 9,500 feet. Piceance Basin proved reserves represented approximately 3% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This operating area produced 3.1 MBOE/d or 6% of the Company's 2015 average daily production.

East Texas
The Company's East Texas properties primarily produce natural gas from the Cotton Valley and Travis Peak formations at depths ranging from 7,000 feet to 11,500 feet. Proved reserves for these mature, low-decline producing properties represented approximately 2% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This operating area produced 1.6 MBOE/d or 3% of the Company's 2015 average daily production.

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Drilling and Acreage

The following table sets forth the wells drilled during the periods indicated:

	Year Ended December 31,		
	2015	2014	2013
Gross wells:			
Productive	196	411	340
Dry	—	—	—
	196	411	340
Net development wells:			
Productive	163	407	311
Dry	—	—	—
	163	407	311
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
	—	—	—

As of December 31, 2015, the Company had 2 gross (1 net) wells in progress (no wells were temporarily suspended). This information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and the quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of oil, natural gas or NGL, regardless of whether they generate a reasonable rate of return.

Productive Wells

The following table sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2015. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	3,261	2,900	2,649	2,054	5,910	4,954
Nonoperated	17	4	198	31	215	35
	3,278	2,904	2,847	2,085	6,125	4,989

Developed and Undeveloped Acreage

The following table sets forth information relating to leasehold acreage as of December 31, 2015:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	583	529	142	91	725	620

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Future Acreage Expirations

If production is not established or the Company takes no other action to extend the terms of the related leases, undeveloped acreage will expire over the next three years as follows:

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	13	7	6	3	3	3

The Company's investment in developed and undeveloped acreage comprises numerous leases. The terms and conditions under which the Company maintains exploration or production rights to the acreage are property-specific, contractually defined and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration. In some instances, the Company may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, the Company has generally been successful in obtaining extensions. The Company utilizes various methods to manage the expiration of leases, including drilling the acreage prior to lease expiration or extending lease terms. The Company currently has no plans to develop or extend the lease terms on any of the acreage related to leases that are due to expire in 2016.

Reserve Data

Proved Reserves

The following table sets forth estimated proved oil, natural gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2015, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:		
Oil (MMBbls)	94	
NGL (MMBbls)	17	
Natural gas (Bcf)	388	
Total (MMBOE)	175	
Estimated proved undeveloped reserves:		
Oil (MMBbls)	—	
NGL (MMBbls)	—	
Natural gas (Bcf)	—	
Total (MMBOE)	—	
Estimated total proved reserves:		
Oil (MMBbls)	94	
NGL (MMBbls)	17	
Natural gas (Bcf)	388	
Total (MMBOE)	175	
Proved developed reserves as a percentage of total proved reserves	100	%
Standardized measure of discounted future net cash flows (in millions) [1]	$995	

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Representative NYMEX prices: (2)	
Oil (Bbl)	$50.16
Natural gas (MMBtu)	$2.59

(1) This measure is not intended to represent the market value of estimated reserves.

(2) In accordance with Securities and Exchange Commission ("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.

During the year ended December 31, 2015, the Company's proved undeveloped reserves ("PUDs") decreased to zero from 68 MMBOE at December 31, 2014. The decrease was due to 64 MMBOE of negative revisions (36 MMBOE due to lower commodity prices, 15 MMBOE due to uncertainty regarding the Company's future commitment to capital, 11 MMBOE due to the SEC five-year development limitation on PUDs and 2 MMBOE due to asset performance) and 4 MMBOE of PUDs developed during 2015. During the year ended December 31, 2015, the Company incurred approximately $68 million in capital expenditures to convert the 4 MMBOE of reserves that were classified as PUDs at December 31, 2014, to proved developed reserves.

As a result of the uncertainty regarding the Company's future commitment to capital, the Company reclassified all of its PUDs to unproved as of December 31, 2015. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details regarding the Company's going concern uncertainty.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGL that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, natural gas and NGL that are ultimately recovered. Future prices received for production may vary, perhaps significantly, from the prices assumed for the purposes of estimating the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows should not be construed as the market value of the reserves at the dates shown. The 10% discount factor required to be used under the provisions of applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry. The standardized measure of discounted future net cash flows is materially affected by assumptions regarding the timing of future production, which may prove to be inaccurate.

The reserve estimates reported herein were prepared by independent engineers, DeGolyer and MacNaughton. 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 the Company. When preparing the reserve estimates, the independent engineering firm did not independently verify the accuracy and completeness of the information and data furnished by the Company 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 questions relating thereto. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years. 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.

The Company's internal control over the preparation of reserve estimates is a process designed to provide reasonable assurance regarding the reliability of the Company's reserve estimates in accordance with SEC regulations. The preparation of reserve estimates was overseen by LINN Energy's Corporate Reserves Manager, who has Master of Petroleum Engineering and Master of Business Administration degrees and more than 30 years of oil and natural gas industry experience. The reserve estimates were reviewed and approved by LINN Energy's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see “Supplemental Oil and Natural Gas Data (Unaudited)” in Item 8. “Financial Statements and Supplementary Data.” The Company has not filed reserve estimates with any federal authority or agency, with the exception of the SEC.

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Operational Overview

General

The Company generally seeks to be the operator of its properties so that it can develop drilling programs and optimization projects that not only replace production, but add value through reserve and production growth and future operational synergies. Many of the Company's wells are completed in multiple producing zones with commingled production and long economic lives.

Marketing

The Company's oil production is primarily sold under market-sensitive contracts that are typically priced at a differential to the New York Mercantile Exchange ("NYMEX") price or at purchaser posted prices for the producing area, and as of December 31, 2015, approximately 85% of its oil production was sold under short-term contracts. Oil in Utah is difficult to transport and has historically been confined primarily to the Salt Lake City market, which is largely dependent on the supply and demand of oil in the area, but is also sold to marketers who move the oil via rail to markets outside of Salt Lake City.

The Company's 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 due to the natural gas quality and the proximity to major consuming markets. The Company's natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. Under percentage-of-proceeds contracts, the Company receives a percentage of the resale price received by the purchaser for sales of residual natural gas and NGL recovered after transportation and processing of natural gas. These purchasers sell the residual natural gas and NGL based primarily on spot market prices. Under percentage-of-index contracts, the Company receives a price for natural gas based on indexes published for the producing area. Although exact percentages vary daily, as of December 31, 2015, approximately 90% of the Company's natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. In certain circumstances, the Company has entered into natural gas processing contracts whereby the residual natural gas is sold under short-term contracts but the related NGL are sold under long-term contracts. In all such cases, the residual natural gas and NGL are sold at market-sensitive index prices.

The Company's natural gas is transported through its own and third-party gathering systems and pipelines. The Company incurs processing, gathering and transportation expenses to move its 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. In certain instances, the Company enters into firm transportation contracts on interstate and intrastate pipelines to assure the delivery of its natural gas to market. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. The Company is negatively impacted by the minimum monthly charge for the Rockies Express, Wyoming Interstate Company and Ruby pipelines. The Company somewhat mitigates this impact through various marketing arrangements. In addition, in California, the Company has firm transportation contracts to assure its ability to purchase a portion of its consumed natural gas outside of the California markets.

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The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2015:

Pipeline	From	To	Quantity	Term	Demand Charge per MMBtu		Remaining Contractual Obligations
			(Avg. MMBtu/d)				(in thousands)
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 1/2018	$1.13	(1)	$21,558
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	6/2009 to 11/2019	1.09	(1)	15,427
Questar Pipeline	Chipeta Plant, UT	Various UT locations	6,200	2/2013 to 2/2021	0.17		1,559
Ruby Pipeline	Opal, WY	Malin, OR	37,857	8/2011 to 7/2021	0.95		73,292
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	37,857	8/2011 to 7/2021	0.31		23,662
Questar Pipeline	Chipeta Plant, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.26		3,209
Questar Pipeline	Brundage Canyon, UT	Chipeta Plant, UT	15,640	9/2013 to 8/2023	0.17		8,274
Total							$146,981

(1) Based on weighted average cost.

Steaming Operations

The Company’s 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. The Company utilizes cyclic steam and/or steam flood recovery methods on these assets.

The Company’s use of these oil recovery methods exposes it to certain annual greenhouse gas emissions obligations in California. The state provides for a certain number of free allowances to offset a portion of the projected emissions. The remainder of the allowances must be purchased at any of the California carbon allowance auctions held in February, May, August and November of each year or in over-the-counter transactions. The Company believes it has met its obligations for the year ended December 31, 2015.

Cogeneration Steam Supply

The Company believes one of the primary methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on its properties. These cogeneration facilities include a 38 megawatt (“MW”) facility and an 18 MW facility located in the Midway-Sunset Field and a 42 MW facility 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.

Conventional Steam Generation

The Company also owns 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 the Company’s targeted production and the price of natural gas compared to the realized price of oil sold. Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location and, to some extent, the aggregated cost of steam generation. The Company’s 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 the Company purchases to generate steam and electricity is primarily based on California price indexes. The Company pays distribution/transportation charges for the delivery of natural gas to its various locations where it uses the natural gas

for steam generation purposes. In some cases, this transportation cost is embedded in the price of the natural gas the Company purchases.
Electricity
Generation
The total average electrical generation capacity of the Company's three cogeneration facilities, which are centrally located on certain of its oil producing properties, was approximately 90 MW for the year ended December 31, 2015. The steam generated by each facility is capable of being delivered to numerous wells that require steam for the enhanced oil recovery

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Item 1. Business - Continued

process. The sole purpose of the cogeneration facilities is to reduce the steam costs in the Company's heavy oil operations and secure operating control of the respective 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 the Company's cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of the Company's power contracts. The Company views any profit or loss from the generation of electricity as a decrease or increase, respectively, to its total cost of producing heavy oil in California.

Sales Contracts

The Company sells electricity produced by its cogeneration facilities under long-term contracts approved by the California Public Utilities Commission ("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: The Company's Public Utilities Regulatory Policy Act of 1978, as amended ("PURPA") purchaser power agreement ("PPA") with PG&E became effective on October 1, 2012, for a term of seven years. Because the rated capacity of the Company's Cogen 18 facility is less than 20 MW, it continues to be eligible for PPAs pursuant to the PURPA.
- Cogen 42 facility: Pursuant to a competitive solicitation, the Company's request for offers ("RFO") PPA with Edison became effective on July 1, 2014, for a term of seven years.
- Cogen 38 facility: The Company's legacy PPA expired in March 2012, at which time a transition PPA with PG&E became effective. The Company participated in a competitive solicitation, which resulted in the execution of a RFO PPA with Edison that became effective on July 1, 2015, for a term of seven years.

Under the PURPA PPA for the Company's Cogen 18 facility, the Company is paid the CPUC-determined short run avoidance cost energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPAs for the Company's Cogen 42 and Cogen 38 facilities, the Company is paid a negotiated energy and capacity price stipulated in the contract.

See Item 1A. "Risk Factors" – "We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and cash flows."

The following table sets forth information regarding the Company's cogeneration facilities and contracts for the year ended December 31, 2015:

Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day in 2015
Cogen 18	PURPA	PG&E	Sept. 2019	9	6	6,500
Cogen 42	RFO	Edison	June 2021	36	4	13,900
Cogen 38	RFO	Edison	June 2022	35	—	16,400

Principal Customers

For the year ended December 31, 2015, sales of oil, natural gas and NGL to Tesoro Corporation, Phillips 66 and Exxon Mobil Corporation accounted for approximately 24%, 23% and 20%, respectively, of the Company's sales. If the Company were to lose any one of its major oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of its oil and natural gas in that particular purchaser's service area. If the Company were to lose a purchaser, it believes it could identify a substitute purchaser. However, if one or more of these large purchasers ceased purchasing oil and natural gas altogether, it could have a detrimental effect on the oil and natural gas market in general and on the prices and volumes of oil, natural gas and NGL that the Company is able to sell.

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Item 1. Business - Continued

Competition
The oil and natural gas industry is highly competitive. The Company encounters strong competition from other independent operators and master limited partnerships in acquiring properties, contracting for drilling and other related services, and securing trained personnel. The Company is also 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. The Company is unable to predict when, or if, such shortages may occur or how they would affect its drilling program.

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. The Company may be liable for environmental damages caused by previous owners of property it purchases and leases. As a result, the Company may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate funds available for acquisitions or development, or result in the loss of properties. In addition, the Company participates in wells on a nonoperated basis and therefore may be limited in its ability to control the risks associated with the operation of such wells.

In accordance with customary industry practices, the Company maintains insurance against some, but not all, potential losses. The Company cannot provide assurance that any insurance it obtains will be adequate to cover any losses or liabilities. The Company has elected to self-insure for certain items for which it has 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 the Company’s financial position, results of operations and cash flows. For more information about potential risks that could affect the Company, see Item 1A. “Risk Factors.”

Title to Properties
Prior to the commencement of drilling operations, the Company conducts a title examination and performs curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, the Company is typically responsible for curing any title defects at its expense prior to commencing drilling operations. As a result, the Company has obtained title opinions on a significant portion of its properties and believes that it has satisfactory title to its producing properties in accordance with standards generally accepted in the industry.

Seasonal Nature of Business
Seasonal weather conditions and lease stipulations can limit the drilling and producing activities and other operations in regions of the U.S. in which the Company operates. These seasonal conditions can pose challenges for meeting the well drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, Company 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 in the fall. The demand for natural gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies sometimes lessen this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations.

Environmental Matters and Regulation
The Company’s 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. The Company’s 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:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;

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- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands located within wilderness, wetlands, areas inhabited by endangered species and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from operations; and
- require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

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 affects profitability. 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 the Company and its operations include, among others, the following U.S. federal laws and regulations:

- Clean Air Act ("CAA"), and its amendments, which governs air emissions;
- Clean Water Act, which governs discharges to and excavations within the waters of the U.S.;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as "Superfund");
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- National Environmental Policy Act, which governs oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which 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 natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic 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 the Company's wells and to limit the number of wells or locations it 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.

The Company believes that it substantially complies with all current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its business, financial condition, results of operations or cash flows. Future regulatory issues that could impact the Company include new rules or legislation relating to the items discussed below.

Climate Change

In December 2009, the Environmental Protection Agency ("EPA") determined that emissions of carbon dioxide, methane and other "greenhouse gases" ("GHG") 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 has begun 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. In addition, in September 2015, the EPA published a proposed rule that would update and expand the New Source Performance Standards by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the U.S., including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. In addition, in 2015, the U.S. participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement will be open for signing on April 22, 2016, and will require 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. Legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the U.S. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. See “California GHG Regulations” below for additional details on current GHG regulations in the state of California.

California GHG Regulations

In October 2006, California adopted the Global Warming Solutions Act of 2006 (“Assembly Bill 32”), which established a statewide “cap and trade” program with an enforceable compliance obligation beginning with 2013 GHG emissions. The program is designed to reduce the state’s GHG emissions to 1990 levels by 2020. Assembly Bill 32 sets maximum limits or caps on total emissions of GHGs from industrial sectors of which the Company is a part, as its California operations emit GHGs. The cap will decline annually through 2020. The Company is required to remit compliance instruments for each metric ton of GHG that it emits, 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 Assembly Bill 32, the Company will be granted a certain number of California carbon allowances (“CCA”) and the Company will need to purchase CCAs and/or offset credits to cover the remaining amount of its emissions. Compliance with Assembly Bill 32 could significantly increase the Company’s capital, compliance and operating costs and could also reduce demand for the oil and natural gas the Company produces. The Company’s cost of acquiring compliance instruments in 2015 was approximately $2.00 per barrel of its California production. In the future, 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 the Company’s ability to limit its GHG emissions and implement cost-containment measures. The cap and trade program is currently scheduled to be in effect through 2020, although it may be continued thereafter.

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, on May 9, 2014, the EPA announced an advance notice of proposed rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and natural gas exploration or production. Further, in March 2015, the Department of the Interior’s Bureau of Land Management (“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. In September 2015, a federal district judge in Wyoming, in litigation pursued by several states, industry associations and an Indian tribe, granted a preliminary injunction against BLM’s enforcement of the new rule; the litigation remains pending. In addition, 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 Safe Drinking Water Act, the Toxic Substances Control Act and/or other regulatory mechanisms. President Obama created the Interagency Working

Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources. 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. For example, both Texas and Louisiana 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,

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some of which have resulted in tighter regulation (including, most recently, new regulations in California requiring a permit to conduct well stimulation), bans, and/or recognition of local government authority to implement such restrictions. In many instances, litigation has ensued, some of which remains pending. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for the Company to perform fracturing to stimulate production from tight formations. 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 the Company's revenues, results of operations and net cash provided by operating activities.

The Company uses a significant amount of water in its hydraulic fracturing operations. The Company's inability to locate sufficient amounts of water, or dispose of or recycle water used in its drilling and production operations, could adversely impact its operations. Moreover, new environmental initiatives and regulations could include restrictions on the Company's 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.

Finally, in some instances, the operation of underground injection wells has been alleged to cause earthquakes. Such issues have sometimes led to orders prohibiting continued injection in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Future orders or regulations addressing concerns about seismic activity from well injection could affect the Company, either directly or indirectly, depending on the wells affected.

Endangered Species Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. Some of the Company's operations may be located in areas that are designated as habitats for endangered or threatened species. The Company believes that it is currently in substantial compliance with the ESA. However, the designation of previously unprotected species as being endangered or threatened could cause the Company to incur additional costs or become subject to operating restrictions in areas where the species are known to exist.

Air Emissions

On August 15, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. These standards require operators to capture the gas from natural gas well completions and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and existing wells that are refractured. Further, the finalized regulations also establish specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. The EPA amended these rules in December 2014 to specify requirements for different flowback stages and to expand the rules to cover more storage vessels, among other changes. These rules may require changes to the Company's operations, including the installation of new equipment to control emissions.

The Company's costs for environmental compliance may increase in the future based on new environmental regulations. For example, in September 2015, the EPA published proposed rules that would "aggregate" certain oil and gas production facilities for purposes of determining the applicability of certain CAA regulatory requirements. In January 2016, the BLM proposed rules to require additional efforts by producers to reduce venting, flaring and leaking of natural gas produced on federal and Native American lands.

Natural Gas Sales and Transportation

Section 1(b) of the Natural Gas Act ("NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC") as a natural gas company under the NGA. The Company believes that the natural gas pipelines in its 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 the Company’s natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts,

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or Congress. In the event the Company's gathering facilities are reclassified to FERC-regulated transmission services, it may be required to charge lower rates and its 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 the Company 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 owned by the Company. 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 utilities have been relieved of their PURPA obligation to enter into new contracts with cogeneration QFs larger than 20 MW. While the California utilities are still required to enter into new contracts with smaller facilities, such as the Company's Cogen 18 facility, there is no assurance that the Company will be able to secure new contracts upon the expiration of the existing contracts for its larger facilities. Even if new contracts are available for the Company's larger facilities, there is no assurance that the prices and terms of such contracts will not adversely affect the Company's 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 the Company, are under the regulatory purview of the CPUC. While the Company is 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 the Company, as is other regulatory oversight provided by the CPUC to the electricity market in California.

Operations on Indian Lands

A portion of the Company's leases and drill-to-earn arrangements in the Uinta Basin operating area and some of the Company's future leases in this and other operating areas may be subject to laws promulgated by any 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 the Company's operations, cause delays in obtaining necessary approvals or permits, or result in losses or cancellations of its oil and natural gas leases, which in turn may materially and adversely affect the Company's 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 the Company's pipelines. These determinations may affect the costs the Company incurs in complying with applicable safety regulations.

Future Impacts and Current Expenditures

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2015, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of its facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2016 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Employees

As of December 31, 2015, the Company had no employees. All former employees of the Company that were retained after the LINN Energy transaction became employees of Linn Operating, Inc. ("LOI"), a subsidiary of LINN Energy, and along with other LOI personnel, provide services and support to the Company in accordance with an agency agreement and power of attorney between the Company and LOI.

Principal Executive Offices

The Company is a Delaware limited liability company with headquarters in Houston, Texas. The principal executive offices are located at 600 Travis, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

Available Information

The Company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to these reports are available free of charge through LINN Energy's website, www.linnenergy.com, as soon as reasonably practicable after they are electronically filed with, or furnished to the SEC. Information on LINN Energy's website should not be considered a part of, or incorporated by reference into, this Annual Report on Form 10-K.

The SEC maintains an internet website that contains these reports at www.sec.gov. Any materials that the Company files with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond the Company's control. These statements may include discussions about the Company's and/or LINN Energy's:

- business strategy;
- financial strategy;
- ability to obtain additional funding from LINN Energy;
- effects of legal proceedings;
- drilling locations;
- oil, natural gas and NGL reserves;
- realized oil, natural gas and NGL prices;
- production volumes;
- capital expenditures;
- economic and competitive advantages;
- credit and capital market conditions;
- regulatory changes;
- lease operating expenses, general and administrative expenses and development costs;

• future operating results;

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- plans, objectives, expectations and intentions; and
- integration of the assets and operations acquired in the exchanges of properties and commencement of activities in LINN Energy's strategic alliances with GSO Capital Partners LP and Quantum Energy Partners, which may take longer than anticipated, may be more costly than anticipated as a result of unexpected factors or events and may have an unanticipated adverse effect on the Company's business.

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. "Business;" Item 1A. "Risk Factors;" Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on Company expectations, which reflect estimates and assumptions made by Company management. These estimates and assumptions reflect management's best judgment based on currently known market conditions and other factors. Although the Company believes such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond its control. In addition, management's assumptions may prove to be inaccurate. The Company cautions that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and it cannot assure any reader that such statements will be realized or the events will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements due to factors set forth in Item 1A. "Risk Factors" and elsewhere in this Annual Report on Form 10-K. The forward-looking statements speak only as of the date made and, other than as required by law, the Company undertakes no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity are described below. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

If we are unable to repay or refinance our existing and future debt as it becomes due, whether at maturity or as a result of acceleration, we may be unable to continue as a going concern.

We have significant indebtedness under our November 2020 Senior Notes and September 2022 Senior Notes (collectively, "Notes") and our Credit Facility. As of February 29, 2016, we had an aggregate amount of approximately $1.7 billion outstanding under our Notes and our Credit Facility (with additional borrowing capacity of less than $1 million). As a result of our indebtedness, we use a significant portion of our cash flow to pay interest and principal (when due) on our Notes and Credit Facility, which reduces the cash available to finance our operations and other business activities and limits our flexibility in planning for or reacting to changes in our business and the industry in which we operate.

Based on our current estimates and expectations for commodity prices in 2016, we do not expect to remain in compliance with all of the restrictive covenants contained in our Credit Facility throughout 2016 unless those requirements are waived or amended. Additionally, the borrowing base under our Credit Facility is subject to redetermination in April 2016. Because the Credit Facility is effectively fully drawn, any reduction in the borrowing base would require us to make mandatory prepayments to the extent existing indebtedness exceeds the new borrowing base. We also have substantial interest payments due during the next twelve months on our Notes and our Credit Facility. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in our Credit Facility or the indentures governing our Notes, an Event of Default (as defined in the applicable agreements) could result, which would permit acceleration of the indebtedness under certain circumstances and could result in an Event of Default and acceleration of our other debt and permit our secured lenders to foreclose on any of our assets securing such debt. Any accelerated debt would become immediately due and payable.

While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient. The uncertainty associated with our ability to meet our obligations as they become due raises substantial doubt about our ability to continue as a going concern. The report of the Company's independent registered public accounting firm that accompanies its audited financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern.

LINN Energy may not continue to provide funding to us for capital expenditures or other cash shortfalls.

Historically, LINN Energy has contributed capital to us to fund capital expenditures and other cash shortfalls but LINN Energy is not obligated to continue to provide funding to us, nor is LINN Energy a guarantor of any of our indebtedness. LINN Energy's credit facility contains certain restrictions on LINN Energy's ability to contribute capital or loan funds to us. In addition, LINN Energy is currently in default under its credit facility and is not able to make additional borrowings to provide funding to us. Absent funding from LINN Energy, we may not have sufficient cash available to finance our operations and other business activities.

We are currently in default under the Credit Facility and the indenture governing the 6.375% senior notes due September 2022.

Under the Credit Facility, we are required to deliver audited financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements includes such going concern explanation, we are currently in default under the Credit Facility.

If we are unable to obtain a waiver or other suitable relief from the lenders under the Credit Facility prior to the expiration of the 30 day grace period, an Event of Default will result and the lenders holding a majority of the commitments under the Credit Facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. If we are unable to obtain a waiver from or otherwise reach an agreement with the lenders under the Credit Facility and the indebtedness under the Credit Facility is accelerated, then an Event of Default under the Notes would occur, which would, to the extent the applicable trustee or holders so elect, result in the acceleration of the Notes.

Additionally, the indenture governing our 6.375% senior notes due September 2022 (the "Berry 2022 Senior Notes Indenture") required us to make an interest payment on March 15, 2016. We elected to exercise our right to the grace period and, as a result, we are currently in default under the Berry 2022 Senior Notes Indenture. If we fail to make the interest payment within the 30 day grace period and are otherwise unable to obtain a waiver or other suitable relief from the holders under the Berry 2022 Senior Notes Indenture prior to the expiration of the 30 day grace period, an Event of Default (as defined in the Berry 2022 Senior Notes Indenture) will result and the trustee or noteholders holding at least 25% in the aggregate principal amount of the series of our September 2022 Senior Notes could accelerate such notes, causing our September 2022 Senior Notes to be immediately due and payable.

An Event of Default under the Berry 2022 Senior Notes Indenture triggers a cross-default under the Credit Facility and, as discussed above, if the lenders so elect would result in acceleration under the Credit Facility. An acceleration under the Berry 2022 Senior Notes Indenture or the Credit Facility would result in cross-default under other Berry senior notes and, if the trustee or noteholders so elect, acceleration thereunder.

If lenders and noteholders accelerate our outstanding indebtedness, it will become immediately due and payable and we will not have sufficient liquidity to repay those amounts. We are currently in discussions with various stakeholders and are pursuing or considering a number of actions, but there can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed to meet certain obligations, and we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

LINN Energy is currently in default under the LINN Energy credit facility, the LINN Second Lien Indenture and the LINN Energy Senior Notes Indenture, which default triggers a default under the Credit Facility and may result in acceleration thereunder. Acceleration under the Credit Facility will trigger a default under the Berry Senior Notes Indenture and may result in acceleration thereunder.

Under the LINN Energy credit facility, LINN Energy is required to deliver audited consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by LINN Energy's auditors with respect to LINN Energy's consolidated financial statements includes such going concern explanation, LINN Energy is

currently in default under the LINN Energy credit facility. A default under the LINN Energy credit facility triggers a default under the Credit Facility.

If LINN Energy is unable to obtain a waiver or other suitable relief from the lenders under the LINN Energy credit facility prior to the expiration of the 30 day grace period, an Event of Default will result and the lenders holding a majority of the commitments under the LINN Energy credit facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. An Event of Default under the LINN Energy credit facility will also result in an Event of Default under the Credit Facility, which in the absence of a waiver or other suitable relief and upon the election of the agent or lenders holding a majority of commitments under the Credit Facility would result in the acceleration of indebtedness under the Credit Facility. Such Event of Default would trigger an Event of Default under the indentures governing the Notes (the "Berry Senior Notes Indentures"). If such Event of Default continues beyond any applicable cure periods, such Event of Default could result in an acceleration of the Notes.

Additionally, the indenture governing LINN Energy's second lien notes (the "LINN Energy Second Lien Indenture") required LINN Energy to deliver mortgages by February 18, 2016, subject to a 45 day grace period. LINN Energy elected to exercise its right to the grace period and, as a result, LINN Energy is currently in default under the LINN Energy Second Lien Indenture. If LINN Energy does not deliver the mortgages within the 45 day grace period or is otherwise unable to obtain a waiver or other suitable relief from the holders under the LINN Energy Second Lien Indenture prior to the expiration of the 45 day grace period, an Event of Default will result under the LINN Energy Second Lien Indenture.

Finally, the indentures (the "LINN Energy Senior Notes Indentures") governing LINN Energy's 6.50% Senior Notes due 2021 and LINN Energy's 7.75% Senior Notes due 2021 required LINN Energy to make interest payments on March 15, 2016. LINN Energy elected to exercise its right to the grace period and, as a result, LINN Energy is currently in default under the LINN Energy Senior Notes Indentures. A default under the LINN Energy Senior Notes Indenture triggered a default under the LINN Energy credit facility and the Credit Facility. If LINN Energy fails to make the interest payments within the 30 day grace period and is otherwise unable to obtain a waiver or other suitable relief from the holders under the LINN Energy Senior Notes Indentures prior to the expiration of the 30 day grace period, an Event of Default (as defined in the applicable indenture) will result under the LINN Energy Senior Notes Indentures.

An Event of Default under each of the LINN Energy Second Lien Indenture and the LINN Energy Senior Notes Indentures triggers a cross-default under the Credit Facility and, as discussed above, if the applicable lenders so elect would result in acceleration under the Credit Facility. An acceleration under the Credit Facility would result in cross-default under Berry Senior Notes Indentures and, if the applicable trustee or noteholders so elect, acceleration thereunder.

If lenders, and subsequently noteholders, accelerate our outstanding indebtedness, it will become immediately due and payable and we will not have sufficient liquidity to repay those amounts. We are currently considering a number of actions, but there can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed to meet certain obligations, and we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

We may seek the protection of the United States Bankruptcy Court ("Bankruptcy Court") which may harm our business.

LINN Energy has engaged financial and legal advisors to assist it in, among other things, analyzing various strategic alternatives to address its and our liquidity and capital structure, including strategic and refinancing alternatives through a private restructuring. However, a filing under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11") may be unavoidable. Seeking Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. As long as a Chapter 11 proceeding continues, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. Bankruptcy Court protection also might make it more difficult to retain management and other key personnel necessary to the success and growth of our business. Also during the Chapter 11 proceedings, our ability to enter into new commodity derivatives covering additional estimated future production would be dependent upon either entering into unsecured hedges or obtaining Bankruptcy Court approval to enter into secured hedges. Furthermore, counterparties under our existing hedge transactions may elect to terminate those transactions in connection with a bankruptcy filing without our consent.

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Any reduction of the borrowing base under our Credit Facility will require us to repay that portion of indebtedness that exceeds the new borrowing base under our Credit Facility earlier than anticipated, which will adversely impact our liquidity.

As of February 29, 2016, total borrowings (including outstanding letters of credit) under our Credit Facility were approximately $899 million with less than $1 million available. Our Credit Facility is subject to scheduled redeterminations of its borrowing base, semi-annually in April and October, based primarily on reserve reports using lender commodity price expectations at such time. Additionally, the lenders under our Credit Facility have the ability to request an interim redetermination of the borrowing base once between scheduled redeterminations. Continued low commodity prices, reductions in our capital budget and the resulting reserve write-downs are expected to adversely impact future redeterminations.

Because our Credit Facility is effectively fully drawn, any reduction in the Credit Facility’s borrowing base will require us to make mandatory prepayments under the Credit Facility to the extent existing indebtedness under the Credit Facility exceeds the new borrowing bases. Although LINN Energy is not required to, it may choose to contribute or otherwise provide cash to us or post restricted cash on our behalf, which would reduce its liquidity position. We may have insufficient cash on hand to be able to make mandatory prepayments under the Credit Facility. Any failure to repay indebtedness in excess of our borrowing base in accordance with the terms of the Credit Facility would constitute an Event of Default under the Credit Facility. Such Event of Default would permit our lenders to accelerate the debt, which, if actually accelerated, would become immediately due and payable and could result in a cross-default and cross-acceleration under our other outstanding indebtedness, and could permit our secured lenders to foreclose on any of our assets securing such indebtedness.

Our ability to comply with financial covenants and ratios in our Credit Facility is affected by events beyond our control, including, among other things, continued low commodity prices. Absent a waiver or amendment, failure to meet these covenants and ratios could result in a default and potentially an acceleration of our existing indebtedness.

The Credit Facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Based on current estimates and expectations for commodity prices in 2016, we do not expect to remain in compliance with all of the financial covenants and ratios throughout 2016 unless those requirements are waived or amended. Our inability to comply with the required financial ratios will, if not amended or waived, result in a default under the Credit Facility.

In addition, the Credit Facility requires delivery of audited financial statements without a going concern or like qualification or explanation to the lenders no later than 90 days after the end of our fiscal year. Due to delivery of the audit report with such going concern explanation, we are in default under the Credit Facility. While the audit opinion is as of December 31, 2015, the default under the Credit Facility does not occur until we have failed to deliver an audit opinion without a going concern or like qualification on explanation, which is the filing date.

A default under the Credit Facility, if not cured or waived, could result in an Event of Default which permits the acceleration of all indebtedness outstanding thereunder. The accelerated debt would become immediately due and payable, which would in turn trigger cross-acceleration under our other debt. In addition, if an Event of Default under the Credit Facility occurs, the lenders could foreclose on the collateral and compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on our Notes. If the amounts outstanding under the Credit Facility, our Notes or any of our other indebtedness were to be accelerated, our assets may not be sufficient to repay in full the money owed to the lenders or to our other debt holders and we may be unable to borrow sufficient funds to refinance our debt. Even if new financing were then available, any such financing may not be on terms that are acceptable to us and may impose financial restrictions and other covenants on us that may be more restrictive than the Credit Facility or the indentures governing our Notes.

Restrictive covenants in the Credit Facility and in the indentures governing the Notes could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Restrictive covenants in the Credit Facility and in the indentures governing the Notes impose significant operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things:

- make distributions to our owner or make other restricted payments;

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- incur or guarantee additional indebtedness;
- refinance certain indebtedness;
- create or incur liens;
- engage in certain mergers or consolidations or otherwise dispose of all or substantially all of our assets;
- make certain investments or acquisitions;
- make certain sales, dispositions or transfers of assets;
- engage in specified transactions with subsidiaries and affiliates;
- repurchase, redeem or retire our Notes; and
- pursue other corporate activities.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants in the Credit Facility and in the indentures governing the Notes. The restrictions contained in the Credit Facility and those indentures could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise to restrict our activities or business plan; and
- adversely affect our ability to finance our operations, enter into acquisitions or to engage in other business activities that would be in our interest.

We have a significant level of debt, which could have significant consequences for our business and future prospects.
As of February 29, 2016, we had an aggregate amount of approximately $1.7 billion outstanding under our Notes and our Credit Facility (with additional borrowing capacity of less than $1 million). Our debt and the limitations imposed on us by our existing or future debt agreements could have significant consequences for our business and future prospects, including the following:

- we will be required to dedicate a significant portion of our cash flow to payments of interest and principal on our Credit Facility and Notes when due;
- we may be limited in our flexibility to plan for or react to changes in our business and industry in which we operate;
- we may not be able to finance our operations and other business activities; and
- we may have a competitive disadvantage relative to our competitors that have less debt.

Our ability to make payments on and to refinance our indebtedness, including our Credit Facility and Notes, and to fund planned capital expenditures will depend on our ability to generate cash flow in the future. We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil, natural gas and NGL prices, economic and financial conditions in our industry and the global economy, the impact of legislative or regulatory actions on how we conduct our business or competitive initiatives of our competitors, are beyond our control. Consequently, our future cash flow may be insufficient to meet our debt obligations and commitments. Any cash flow insufficiency could negatively impact our business, financial condition and results of operations. To the extent we are unable to make scheduled interest payments or repay our indebtedness as it becomes due or at maturity with cash on hand, we will need to refinance our debt, sell assets or seek additional financing. Additional indebtedness and financing may not be available to us in the future for the refinancing or repayment of existing indebtedness, and we may not be able to complete asset sales in a timely manner sufficient to make such repayments.

Despite our current level of indebtedness, we may still be able to incur more debt. This could further exacerbate the risks associated with our substantial indebtedness.
We may be able to incur additional indebtedness in the future. Although the credit agreement governing our Credit Facility and the indentures that govern our Notes contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and the additional indebtedness incurred in compliance with these restrictions could be substantial. Moreover, these restrictions will not prevent us from incurring obligations that do not constitute indebtedness, as defined in the applicable agreements governing our existing indebtedness.

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If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

Our debt rating has been downgraded and liquidity concerns could result in a further downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, liquidity, asset quality, cost structure, product mix and commodity pricing levels. Further ratings downgrades could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit or other credit support for certain obligations.

Our substantial indebtedness, liquidity concerns and potential restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity concerns and potential restructuring transactions may result in uncertainty about our business and cause, among other things:

- our suppliers, vendors, derivatives counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us; and
- third parties to lose confidence in our ability to produce oil, natural gas and NGL, resulting in a significant decline in our revenues, profitability and cash flow.

These events, among others, may have a material adverse effect on our business and operations.

Commodity prices are volatile, and prolonged depressed prices or a further decline in prices would reduce our revenues, net cash provided by operating activities and profitability and would significantly affect our financial condition and results of operations.

Our revenues, profitability, cash flow and the carrying value of our properties depend on the prices of and demand for oil, natural gas and NGL. Historically, the oil, natural gas and NGL markets have been very volatile and are expected to continue to be volatile in the future, and prolonged depressed prices or a further decline in prices will significantly affect our financial results and impede our growth. Changes in oil, natural gas and NGL prices have a significant impact on the value of our reserves and on our net cash provided by operating activities. In addition, revenues from certain wells may exceed production costs and nevertheless not generate sufficient return on capital. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for them, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil, natural gas and NGL;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain price and production controls;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

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Item 1A. Risk Factors - Continued

During 2015, the prices of oil, natural gas and NGL were extremely volatile and declined significantly. Downward pressure on commodity prices has continued in 2016 and may continue for the foreseeable future. The speed and severity of the decline in oil prices from 2014 to 2016 has materially affected our results of operations. If commodity prices continue at current levels for a prolonged period or further decline, our net cash provided by operating activities will decline and our financial position, the quantities of oil and natural gas reserves that we can economically produce, our cash flow available for capital expenditures, our ability to service our debt obligations, our ability to generate free cash flow after capital expenditures and debt service and our ability to access funds under our Credit Facility may be materially and adversely affected.

The sustained oil, natural gas and NGL price declines have resulted in significant impairments of certain of our properties. Future declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in the period incurred.

We evaluate the impairment of our oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. For the year ended December 31, 2015, we recorded noncash impairment charges (before and after tax) of approximately $854 million. Future declines in oil, natural gas and NGL prices, changes in expected capital development, increases in operating costs or adverse changes in well performance, among other things, may result in us having to make additional material write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in the period incurred.

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 anticipated production volumes remain mostly unhedged. Based on current expectations for continued low future commodity prices, reduced hedging market liquidity and potential reduced counterparty willingness to enter into new hedges with us, 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.

Counterparty failure may adversely affect our derivative positions.

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 net cash provided by operating activities, financial condition and results of operations would be adversely affected.

Derivatives legislation and implementing rules could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), enacted in 2010, expands federal oversight and regulation of the derivatives market and entities, such as us, that participate in that market. Those markets involve derivative transactions, which include certain instruments, such as interest rate swaps, forward contracts, option contracts, financial contracts and other contracts, used in our risk management activities. The Dodd-Frank Act requires that most swaps ultimately will be cleared through a registered clearing facility and that they be traded on a designated exchange or swap execution facility, with certain exceptions for entities that use swaps to hedge or mitigate commercial risk. The Dodd-Frank requirements relating to derivative transactions have not been fully implemented by the SEC and the Commodities Futures Trading Commission. When fully implemented, the law and any new regulations could increase the operational and transactional cost of derivatives contracts and affect the number and/or creditworthiness of available counterparties.

In addition, we may transact with counterparties based in the European Union, Canada or other jurisdictions which, like the U.S., are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and impose operational and transactional costs on our derivatives activities.

Unless we replace our reserves, our future reserves and production will decline, which would adversely affect our net cash provided by operating activities, financial condition and results of operations.

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Producing oil, natural gas and NGL reservoirs are characterized by declining production rates that vary depending on reservoir characteristics and other factors. The overall rate of decline for our production will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future oil, natural gas and NGL reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our net cash provided by operating activities, financial condition and results of operations. In addition, given our significant level of indebtedness, current market conditions and restrictive covenants under our debt agreements, we may be unable to finance such potential acquisitions of reserves on terms that are acceptable to us or at all. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. We also may not be successful in raising funds to acquire additional reserves.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of oil, natural gas and NGL in an exact manner. Reserve engineering requires subjective estimates of underground accumulations of oil, natural gas and NGL and assumptions concerning future oil, natural gas and NGL prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. An independent petroleum engineering firm prepares estimates of our proved reserves. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future oil, natural gas and NGL prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual amounts could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Decreases in commodity prices can result in a reduction of our estimated reserves if development of those reserves would not be economic at those lower prices. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGL we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil, natural gas and NGL reserves. We base the estimated discounted future net cash flows from our proved reserves on an unweighted average of the first-day-of-the month price for each month during the 12-month calendar year and year-end costs. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil, natural gas and NGL;
- the amount and timing of actual production;
- capital and operating expenditures;
- the timing and success of development activities;
- supply of and demand for oil, natural gas and NGL; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor required to be used under the provisions of applicable accounting standards when calculating discounted future net cash flows, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Our development operations require substantial capital expenditures, which will reduce our cash available to service debt. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in

our reserves.
The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development and production of oil, natural gas and NGL reserves. These expenditures will reduce our cash available to service debt. We intend to finance our future capital expenditures primarily with net cash provided by

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operating activities. Our net cash provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil, natural gas and NGL we are able to produce from existing wells;
- the prices at which we are able to sell our oil, natural gas and NGL;
- the level of operating expenses; and
- our ability to acquire, locate and produce new reserves.

If our net cash provided by operating activities or the borrowing base under our Credit Facility decreases, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. In addition, as noted previously, our Credit Facility is effectively fully drawn, precluding our ability to utilize our Credit Facility to fund our operations. Our Credit Facility also restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain financing on terms favorable to us, or at all. If net cash provided by operating activities or cash available under our Credit Facility is not sufficient to meet our capital requirements, the failure to obtain such additional financing could result in a curtailment of our development operations, which in turn could lead to a decline in our reserves.

We may decide not to drill some of the prospects we have identified, and locations that we decide to drill may not yield oil, natural gas and NGL in commercially viable quantities.

Our prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, natural gas and NGL prices, the generation of additional seismic or geological information, the current and future availability of drilling rigs and other factors, we may decide not to drill one or more of these prospects. In addition, the cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, natural gas and NGL to be commercially viable after drilling, operating and other costs. As a result, we may not be able to increase or sustain our reserves or production, which in turn could have an adverse effect on our business, financial condition, results of operations and cash flows.

The SEC’s reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be recorded if they relate to wells scheduled to be drilled within five years. As a result of the uncertainty regarding our future commitment to capital, we reclassified all of our proved undeveloped reserves to unproved as of December 31, 2015. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for details regarding our going concern uncertainty.

Our business depends on gathering and transportation facilities. Any limitation in the availability of those facilities would interfere with our ability to market the oil, natural gas and NGL we produce, and could reduce our cash available to service debt and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

The marketability of our oil, natural gas and NGL production depends in part on the availability, proximity and capacity of gathering systems and pipelines. The amount of oil, natural gas and NGL that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport additional production. As a result, we may not be able to sell the oil, natural gas and NGL production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, would interfere with our ability to market the oil, natural gas and NGL we produce, and could reduce our cash available to service debt and adversely impact expected increases in oil, natural gas and NGL

production from our drilling program.
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.

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We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For the year ended December 31, 2015, sales of oil, natural gas and NGL to Tesoro Corporation, Phillips 66 and Exxon Mobil Corporation accounted for approximately 24%, 23% and 20%, respectively, of the Company’s 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 months after production has been delivered. If the purchasers of our oil and natural gas become insolvent, we may be unable to collect amounts owed to us, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of reserves in these areas. Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Drilling for and producing oil, natural gas and NGL are high risk activities with many uncertainties that could adversely affect our financial position, results of operations and cash flows and, as a result, our ability to service debt.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil, natural gas and NGL can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas and NGL or well fluids.

Any of these events can cause increased costs or restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling program or significant increase in costs could impact our financial position, results of operations and cash flows, and as a result, our ability to service debt.

Because we handle oil, natural gas and NGL and other hydrocarbons, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

The operations of our wells, gathering systems, turbines, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. Certain environmental statutes, including the RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, and these costs may not be recoverable from insurance. For a more detailed discussion of environmental and regulatory matters impacting our business, see Item 1. "Business – Environmental Matters and Regulation."

A shortage or increase in the price of natural gas in California could materially and adversely affect our business.

The development of our heavy oil in California is subject to our ability to generate sufficient quantities of steam at an economic cost. We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production, results of operations and cash flows could be materially and adversely impacted.

We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and cash flows.

We are dependent on three cogeneration facilities that, combined, provided approximately 12% of our steam capacity for the year ended December 31, 2015. These facilities are dependent on viable contracts for the sale of electricity. Market fluctuations in electricity prices and regulatory changes in California could adversely affect the economics of our cogeneration facilities and the corresponding increase in the price of steam could significantly impact our operating costs. If we are unable to enter into new or replacement contracts or were to lose existing contracts, we may be unable to meet our steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment could materially and adversely affect our financial condition, results of operations and cash flows. For a more detailed discussion of our electricity sales contracts, see Item 1. "Business – Electricity."

LINN Energy controls us and its indirect interests as our sole equity holder may conflict with the interests of holders of our senior notes.

We are an indirect wholly owned subsidiary of LINN Energy. The interests of LINN Energy may not in all cases be aligned with the interests of the holders of our debt. We are managed by officers and employees of LINN Energy, who will make determinations with respect to our business, our capital expenditures and our cash management. Other than with respect to the agreements governing our indebtedness, there are no contractual restrictions on our ability to make distributions to LINN Energy. Our management could determine to increase our distributions to LINN Energy to support its cash needs, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, if we encounter financial difficulties or become unable to pay our debts as they mature, LINN Energy does not have any liability for any obligations under our senior notes. LINN Energy may also have an interest in pursuing acquisitions, divestitures, financings or other transactions, even though such transactions might involve risks to our business or the holders of our debt. Furthermore, LINN Energy may own businesses that directly or indirectly compete with us. LINN Energy also may pursue acquisition opportunities that may be complementary to LINN Energy's business, and as a result, those acquisition opportunities may not be available to us.

If LINN Energy fails to provide the personnel necessary to conduct our operations, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We do not have any employees. All of our former employees that were retained after the LINN Energy transaction became employees of Linn Operating, Inc. ("LOI"), a subsidiary of LINN Energy, and along with other LOI personnel, provide services and support to us in accordance with an agency agreement and power of attorney between the Company and LOI. We depend on the services of these individuals. If their services are unavailable to us for any reason, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have resulted in delays and increased the costs to plan, design, drill, install, operate and abandon oil and

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natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil, natural gas and NGL we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties. Additionally, the regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our financial condition and results of operations, as well as our ability to service debt. For a description of the laws and regulations that affect us, see Item 1. “Business – Environmental Matters and Regulation.”

Legislation and regulation of hydraulic fracturing could adversely affect our business.

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. For a description of the laws and regulations that affect us, including our hydraulic fracturing operations, see Item 1. “Business – Environmental Matters and Regulation.” If adopted, certain bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. 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 business, financial position, results of operations and net cash provided by operating activities.

We use a significant amount of 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.

Finally, in some instances, the operation of underground injection wells has been alleged to cause earthquakes. Such issues have sometimes led to orders prohibiting continued injection in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Future orders or regulations addressing concerns about seismic activity from well injection could affect us, either directly or indirectly, depending on the wells affected.

Legislation and regulation of greenhouse gases could adversely affect our business.

In December 2009, the Environmental Protection Agency (“EPA“) determined that emissions of carbon dioxide, methane and other “greenhouse gases” (“GHG”) 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 has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act (“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. In addition, in September 2015, the EPA published a proposed rule that would update and expand the New Source Performance Standards by setting additional emissions limits for volatile organic compounds and regulating methane emissions from new and modified sources in the oil and gas industry. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the U.S., including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. In addition, in 2015, the U.S. participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement will be open for signing on April 22, 2016, and will require countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG

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emission reduction goals, every five years beginning in 2020. Legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the U.S. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. For a description of the California “cap and trade” program, see Item 1. “Business – Environmental Matters and Regulation.” 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 business, financial position, results of operations and net cash provided by operating activities.

Recent regulatory changes in California have and may continue to adversely affect our production and operating costs related to our Diatomite assets.

Recent regulatory changes in California have impacted production from our Diatomite assets. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from the California Division of Oil, Gas and Geothermal Resources (“DOGGR”). Berry received a new full-field development approval in late July 2011 from DOGGR, which contained stringent operating requirements. Revisions to the July 2011 project approval letter were received in February 2012. Implementation of these new operating requirements negatively impacted the pace of drilling and steam injection and increased Berry’s operating costs for its Diatomite assets. The requirements continued to affect Berry’s operations through 2015, and we may not be successful in streamlining the review process with DOGGR or in taking additional steps to more efficiently manage our operations to avoid additional delays. In addition, DOGGR may impose additional operational restrictions or requirements. For example, currently DOGGR is developing new regulations for shallow, thermal Diatomite. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets, which could adversely affect our business, financial position, results of operations and net cash provided by operating activities.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

Information concerning proved reserves, production, wells, acreage and related matters are contained in Item 1. “Business.”

The Company’s obligations under its Credit Facility are secured by mortgages on a substantial majority of its oil and natural gas properties. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 3 for additional details about the Credit Facility.

Offices

The Company’s principal corporate office is located at 600 Travis, Suite 5100, Houston, Texas 77002. The Company maintains additional offices in California, Colorado, Texas and Utah.

Item 3. Legal Proceedings

The Company is involved in various lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

Item 4. Mine Safety Disclosure

Not applicable

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Part II

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

As a result of the LINN Energy transaction, Berry is an indirect wholly owned subsidiary of LINN Energy. Berry’s sole member is Linn Acquisition Company, LLC, a direct subsidiary of LINN Energy, and Berry’s equity is not publicly traded.

Dividends

The Company’s predecessor paid a regular dividend of $0.32 per share for the period ended December 16, 2013. The Company has not declared cash dividends since the LINN Energy transaction and due to its debt financing arrangements, its ability to declare and pay dividends is subject to restrictions should it seek to do so in the future. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 3.

Sales of Unregistered Securities

In conjunction with the LINN Energy transaction, the Company converted from a Delaware corporation into a Delaware limited liability company. The conversion of the Company’s common stock into membership interests was not registered and will not be registered under the Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder (“Securities Act”), or any state securities laws, in reliance on Section 4(a)(2) of the Securities Act as these transactions were by an issuer not involving a public offering.

Issuer Purchases of Equity Securities

None

Item 6. Selected Financial Data

Item 6 has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

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

The following discussion and analysis should be read in conjunction with the financial statements and related notes, which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data." The following discussion contains forward-looking statements based on expectations, estimates and assumptions. Actual results may differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, credit and capital market conditions, regulatory changes and other uncertainties, as well as those factors set forth in "Cautionary Statement Regarding Forward-Looking Statements" in Item 1. "Business" and in Item 1A. "Risk Factors."

The reference to a "Note" herein refers to the accompanying Notes to Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Executive Overview

Berry Petroleum Company, LLC ("Berry" or the "Company") was formed as a Delaware limited liability company on December 16, 2013, and is an indirect wholly owned subsidiary of Linn Energy, LLC ("LINN Energy") engaged in the production and development of oil and natural gas. The Company's predecessor, Berry Petroleum Company, was publicly traded from 1987 until December 2013. On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between LINN Energy, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and LINN Energy, under which LinnCo contributed Berry to LINN Energy in exchange for LINN Energy units (see "LINN Energy Transaction" below). Linn Acquisition Company, LLC, a direct subsidiary of LINN Energy, is currently the Company's sole member.

The Company currently has five operating areas in the United States ("U.S."): California, Hugoton Basin, Uinta Basin, Piceance Basin and East Texas. In August and November of 2014, the Company divested all of its properties located in the Permian Basin. For a discussion of the Company's five operating areas, see Item 1. "Business."

Results for the year ended December 31, 2015, included the following:

- oil, natural gas and NGL sales of approximately $575 million compared to $1.3 billion for 2014;
- average daily production of approximately 48.4 MBOE/d compared to 51.7 MBOE/d for 2014;
- net loss of approximately $1.0 billion compared to net income of $23 million for 2014;
- net cash provided by operating activities of approximately $123 million compared to $583 million for 2014;
- capital expenditures, excluding acquisitions, of approximately $152 million compared to $574 million for 2014; and
- 196 wells drilled (all successful) compared to 411 wells drilled (all successful) for 2014.

Going Concern Uncertainty

The Company's liquidity outlook has changed since the third quarter of 2015 due to continued low commodity prices. In addition, the Company's Credit Facility is subject to scheduled redeterminations of its borrowing base, semi-annually in April and October, based primarily on reserve reports using lender commodity price expectations at such time. Continued low commodity prices, reductions in the Company's capital budget and the resulting reserve write-downs are expected to adversely impact the upcoming April redetermination and will likely have a significant negative impact on the Company's liquidity.

As a result of these and other factors, the following issues have adversely impacted the Company's ability to continue as a going concern:

- the Company's ability to comply with financial covenants and ratios in its Credit Facility and indentures has been affected by continued low commodity prices. Absent a waiver or amendment, failure to meet these covenants and ratios would result in a default and, to the extent the applicable lenders so elect, an acceleration of the Company's existing indebtedness, causing such debt of approximately $873 million to be immediately due and payable. Based on the Company's current estimates and expectations for commodity prices in 2016, the Company does not expect to remain in compliance with all of the restrictive covenants contained in its Credit Facility throughout 2016 unless

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those requirements are waived or amended. The Company does not currently have adequate liquidity to repay all of its outstanding debt in full if such debt were accelerated;

- because the Credit Facility is effectively fully drawn, any reduction of the borrowing base under the Company's Credit Facility would require mandatory prepayments to the extent existing indebtedness exceeds the new borrowing base. The Company may not have sufficient cash on hand to be able to make any such mandatory prepayments; and
- the Company's ability to make interest payments as they become due and repay indebtedness upon maturities (whether under existing terms or as a result of acceleration) is impacted by the Company's liquidity. As of February 29, 2016, there was less than $1 million of available borrowing capacity under the Credit Facility.

The Company's management is in the process of evaluating strategic alternatives to help provide the Company with financial stability, but no assurance can be given as to the outcome or timing of this process.

The report of the Company's independent registered public accounting firm that accompanies its audited financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

The Company's Credit Facility contains the requirement to deliver audited financial statements without a going concern or like qualification or exception. Consequently, as of the filing date, March 28, 2016, the Company is in default under the Credit Facility. If the Company is unable to obtain a waiver or other suitable relief from the lenders under the Credit Facility prior to the expiration of the 30 day grace period, an Event of Default (as defined in the applicable agreements) will result and the lenders holding a majority of the commitments under the Credit Facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. If the Company is unable to obtain a waiver from or otherwise reach an agreement with the lenders under the Credit Facility and the indebtedness under the Credit Facility is accelerated, then an Event of Default under the Company's senior notes would occur, which, if it continues beyond any applicable cure periods, would, to the extent the applicable lenders so elect, result in the acceleration of those obligations.

Furthermore, the Company has decided to defer making an interest payment totaling approximately $18 million due March 15, 2016, on the Company's senior notes due September 2022, which resulted in the Company being in default under these senior notes. The indenture governing the notes permits the Company a 30 day grace period to make the interest payments. If the Company fails to make the interest payments within the grace period, or is otherwise unable to obtain a waiver or suitable relief from the holders of these senior notes, an Event of Default will result and if the trustee or noteholders holding at least 25% in the aggregate outstanding principal amount of the notes so elect would accelerate the notes causing them to be immediately due and payable.

An Event of Default under any of the indentures governing the senior notes triggers a cross-default under the Credit Facility and, as discussed above, if the applicable lenders so elect would result in acceleration under the Credit Facility. In addition, as discussed above, an acceleration of the obligations under the Credit Facility, if the applicable lenders so elect, would result in cross-acceleration under the senior notes.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If the Company is unable to reach an agreement with its creditors prior to any of the above described accelerations, the Company could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

The Company is currently in discussions with various stakeholders and is pursuing or considering a number of actions including: (i) obtaining additional sources of capital from asset sales, private issuances of equity or equity-linked securities, debt for equity swaps, or any combination thereof; (ii) pursuing in- and out-of-court restructuring transactions; (iii) obtaining waivers or amendments from its lenders; and (iv) continuing to minimize its capital expenditures, reduce costs and maximize cash flows from operations. There can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed.

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LINN Energy Transaction

On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between LINN Energy, LinnCo, an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and LINN Energy, under which LinnCo contributed Berry to LINN Energy in exchange for LINN Energy units. Under the merger agreement, as amended, Berry’s shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units, after which Berry became an indirect wholly owned subsidiary of LINN Energy. The transaction was valued at approximately $4.6 billion, including the assumption of approximately $2.3 billion of Berry’s debt and net of cash acquired of approximately $451 million.

Predecessor and Successor Reporting

As a result of the impact of pushdown accounting on the acquisition date (see Note 1), the Company’s financial statements and certain note presentations are separated into two distinct periods, the period before the consummation of the LINN Energy transaction (labeled predecessor) and the period after that date (labeled successor), to indicate the application of a different basis of accounting between the periods presented. Despite this separate GAAP presentation, the successor had no independent oil and natural gas operations prior to the acquisition, and, accordingly, there were no operational activities that changed as a result of the acquisition of the predecessor. Consequently, given the continuity of operations, when assessing variance analysis of the historical results of operations and financial performance, the reader may wish to combine predecessor and successor results for the year ended December 31, 2013.

Financing Activities

During the year ended December 31, 2015, the Company repurchased at a discount, on the open market and through a privately negotiated transaction, approximately $65 million of its outstanding senior notes.

In October 2015, the Company entered into an amendment to its Second Amended and Restated Credit Agreement (“Credit Facility”). The spring 2015 semi-annual borrowing base redetermination of the Company’s Credit Facility was completed in May 2015, and as a result of lower commodity prices, the borrowing base under the Credit Facility decreased from $1.4 billion to $1.2 billion, including $250 million posted as restricted cash (discussed below). The fall 2015 semi-annual redetermination was completed in October 2015 and the borrowing base under the Credit Facility decreased from $1.2 billion to $900 million, including the $250 million of restricted cash. In connection with the reduction in Berry’s borrowing base in October 2015, Berry repaid $300 million of borrowings outstanding under the Credit Facility. Continued low commodity prices, reductions in the Company’s capital budget and the resulting reserve write-downs are expected to adversely impact future redeterminations.

In connection with the reduction in Berry’s borrowing base in May 2015, LINN Energy contributed $250 million to Berry to post as restricted cash with Berry’s lenders. As directed by LINN Energy, the $250 million was deposited on Berry’s behalf in a security account with the administrative agent subject to a security control agreement. Berry’s ability to withdraw funds from this account is subject to a concurrent reduction of the borrowing base under the Credit Facility or lender’s consent in connection with a redetermination of such borrowing base. The $250 million may be used to satisfy obligations under the Credit Facility or, subject to restrictions in the indentures governing Berry’s senior notes, may be returned to LINN Energy in the future.

See Note 3 for additional details about the Company’s debt.

Commodity Derivatives

During the year ended December 31, 2015, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for May 2015 through December 2016 to hedge exposure to differentials in certain producing areas and oil swaps for April 2015 through December 2015. In addition, the Company entered into natural gas basis swaps for May 2015 through December 2016 to hedge exposure to the differential in California, where it consumes natural gas in its heavy oil development operations.

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

Results of Operations
The following table presents the Company's results of operations for each of the successor and predecessor periods presented:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Revenues and other:				
Oil sales	$463,369	$1,146,047	$45,655	$1,006,539
Natural gas sales	90,150	125,539	3,416	67,877
NGL sales	21,512	26,816	1,253	28,829
Total oil, natural gas and NGL sales	575,031	1,298,402	50,324	1,103,245
Electricity sales	24,544	40,022	1,444	33,992
Gains (losses) on oil and natural gas derivatives	29,175	78,784	(5,049)	(34,711)
Marketing and other revenues	12,904	14,081	399	8,776
	641,654	1,431,289	47,118	1,111,302
Expenses:				
Lease operating expenses	245,155	364,540	15,410	295,811
Electricity generation expenses	18,057	28,171	1,257	22,485
Transportation expenses	52,160	41,842	2,576	46,774
Marketing expenses	3,809	8,084	376	7,593
General and administrative expenses	85,993	102,787	20,298	122,991
Exploration costs	—	—	—	24,048
Depreciation, depletion and amortization	251,371	302,353	10,845	279,757
Impairment of long-lived assets	853,810	253,362	—	—
Taxes, other than income taxes	70,593	97,708	2,130	57,063
(Gains) losses on sale of assets and other, net	(1,919)	120,786	10,208	(23)
	1,579,029	1,319,633	63,100	856,499
Other income and (expenses)	(77,870)	(88,991)	(3,991)	(96,076)
Income (loss) before income taxes	(1,015,245)	22,665	(19,973)	158,727
Income tax expense (benefit)	(68)	69	—	65,280
Net income (loss)	$(1,015,177)	$22,596	$(19,973)	$93,447

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

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

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Average daily production:				
Oil (MBbls/d)	30.0	36.7	33.1	30.6
Natural gas (MMcf/d)	92.7	79.3	55.1	51.2
NGL (MBbls/d)	2.9	1.8	2.3	2.2
Total (MBOE/d)	48.4	51.7	44.5	41.3
Total production:				
Oil (MBbls)	10,963	13,394	496	10,712
Natural gas (MMcf)	33,852	28,938	826	17,931
NGL (MBbls)	1,061	671	34	760
Total (MBOE)	17,666	18,888	667	14,460
Weighted average prices: (1)				
Oil (Bbl)	$42.27	$85.56	$92.05	$93.96
Natural gas (Mcf)	$2.66	$4.34	$4.14	$3.79
NGL (Bbl)	$20.27	$39.96	$36.85	$37.95
Average NYMEX prices:				
Oil (Bbl)	$48.80	$93.00	$98.88	$98.01
Natural gas (MMBtu)	$2.66	$4.41	$4.38	$3.70
Costs per BOE of production:				
Lease operating expenses	$13.88	$19.30	$23.10	$20.46
Transportation expenses	$2.95	$2.22	$3.86	$3.23
General and administrative expenses	$4.87	$5.44	$30.43	$8.51
Depreciation, depletion and amortization	$14.23	$16.01	$16.26	$19.35
Taxes, other than income taxes	$4.00	$5.17	$3.19	$3.95

(1) Does not include the effect of gains (losses) on derivatives.

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

The following table sets forth information regarding production volumes for fields with greater than 15% of the Company's total proved reserves for each of the periods indicated:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Total production:				
Hugoton Basin Field:				
Oil (MBbls)	—	—	*	*
Natural gas (MMcf)	16,831	7,314	*	*
NGL (MBbls)	814	223	*	*
Total (MBOE)	3,619	1,442	*	*
SJV Diatomite Field:				
Oil (MBbls)	2,939	3,260	103	1,798
Natural gas (MMcf)	—	—	—	—
NGL (MBbls)	—	—	—	—
Total (MBOE)	2,939	3,260	103	1,798
SJV South Midway Field:				
Oil (MBbls)	2,598	*	99	2,431
Natural gas (MMcf)	—	*	—	—
NGL (MBbls)	—	*	—	—
Total (MBOE)	2,598	*	99	2,431
Uinta Field:				
Oil (MBbls)	*	*	76	1,587
Natural gas (MMcf)	*	*	362	6,243
NGL (MBbls)	*	*	8	181
Total (MBOE)	*	*	144	2,810
Midland Basin Field:				
Oil (MBbls)	*	*	75	1,847
Natural gas (MMcf)	*	*	129	2,983
NGL (MBbls)	*	*	24	529
Total (MBOE)	*	*	120	2,874

*Represented less than 15% of the Company's total proved reserves for the year or period indicated.

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales decreased by approximately $723 million or 56% to approximately $575 million for the year ended December 31, 2015, from approximately $1.3 billion for the year ended December 31, 2014, due to lower oil, natural gas and NGL prices and lower production volumes. Lower oil, natural gas and NGL prices resulted in a decrease in revenues of approximately $474 million, $57 million and $21 million, respectively.

Average daily production volumes decreased to approximately 48 MBOE/d for the year ended December 31, 2015, from approximately 52 MBOE/d for the year ended December 31, 2014. Lower oil production volumes resulted in a decrease in revenues of approximately $208 million. Higher natural gas and NGL production volumes resulted in an increase in revenues of approximately $21 million and $16 million, respectively.

Oil, natural gas and NGL sales increased by approximately $145 million or 13% to approximately $1.3 billion for the year ended December 31, 2014, from approximately $50 million and $1.1 billion for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, due to higher production volumes and

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higher natural gas and NGL prices partially offset by lower oil prices. Higher natural gas and NGL prices resulted in an increase in revenues of approximately $16 million and $1 million, respectively, in 2014. Lower oil prices resulted in a decrease in revenues of approximately $111 million in 2014.

Average daily production volumes increased to approximately 52 MBOE/d for the year ended December 31, 2014, from approximately 44 MBOE/d and 41 MBOE/d for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively. Higher oil and natural gas production volumes resulted in an increase in revenues of approximately $205 million and $39 million, respectively, in 2014. Lower NGL production volumes resulted in a decrease in revenues of approximately $5 million in 2014.

The following table sets forth average daily production by operating area:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Average daily production (MBOE/d):				
California	25.8	26.0	23.0	20.8
Hugoton Basin	9.9	4.0	—	—
Uinta Basin	8.0	10.9	9.6	8.0
Piceance Basin	3.1	1.9	2.1	2.3
East Texas	1.6	1.7	1.8	2.0
Permian Basin	—	7.2	8.0	8.2
	48.4	51.7	44.5	41.3

The decrease in average daily production volumes in California in 2015 primarily reflects recent operational challenges in the Company's Diatomite development program, offset by the impact of the properties received in the exchange with Exxon Mobil Corporation ("ExxonMobil") on November 21, 2014. The Company is pursuing various remedies to address Diatomite wells performance and has temporarily curtailed capital spending in this program.

Average daily production volumes in the Hugoton Basin operating area reflect the impact of the properties received in the exchange with Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc. ("Exxon XTO") on August 15, 2014. The decrease in average daily production volumes in the Uinta Basin and East Texas operating areas in 2015 primarily reflects the effects of production declines due to reduced development capital spending. The increase in average daily production volumes in the Piceance Basin operating area in 2015 primarily reflects development capital spending. The decrease in average daily production volumes in the Permian Basin operating area in 2015 and 2014 reflects the properties relinquished in the two exchanges with ExxonMobil and Exxon XTO and the properties sold to Fleur de Lis Energy, LLC ("Permian Basin Assets Sale") on November 14, 2014. The Company had no Permian Basin properties remaining as of December 31, 2014.

The increase in average daily production volumes in California and the Uinta Basin operating area in 2014 primarily reflects development capital spending. The increase in average daily production volumes in California in 2014 also reflects the impact of the properties received in the exchange with ExxonMobil on November 21, 2014. The decrease in average daily production volumes in the Piceance Basin and East Texas operating areas in 2014 primarily reflects the effects of production declines due to reduced development capital spending.

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Electricity Sales
The following table sets forth selected electricity data:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Electricity sales (in thousands)	$24,544	$40,022	$1,444	$33,992
Electricity generation expenses (in thousands)	$18,057	$28,171	$1,257	$22,485
Electric power produced (Mwh/d)	2,012	2,071	2,217	1,950
Electric power sold (Mwh/d)	1,782	1,882	1,999	1,797
Average sales price per Mwh	$37.74	$59.80	$48.15	$53.78
Fuel gas cost per MMBtu (including transportation)	$2.62	$4.52	$4.58	$3.72
Estimated natural gas volumes consumed to produce electricity (MMBtu/d) (1)	13,767	14,948	16,142	14,536

(1) Estimate is based on the historical allocation of fuel costs to electricity.

Electricity sales represent sales to utilities and decreased by approximately $15 million or 39% to approximately $25 million for the year ended December 31, 2015, from approximately $40 million for the year ended December 31, 2014, primarily due to decreases in the average sales price of electricity and electric power sold during the period.

Electricity sales increased by approximately $5 million or 13% to approximately $40 million for the year ended December 31, 2014, from approximately $1 million and $34 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, primarily due to an increase in the average sales price of electricity and electric power sold year over year.

Gains (Losses) on Oil and Natural Gas Derivatives

Gains on oil and natural gas derivatives were approximately $29 million and $79 million for the years ended December 31, 2015, and December 31, 2014, respectively, representing a decrease of approximately $50 million. Gains on oil and natural gas derivatives decreased primarily due to changes in fair value of the derivative contracts. The results for 2014 also include cash settlements of approximately $12 million related to canceled derivatives contracts.

Gains on oil and natural gas derivatives were approximately $5 million and $35 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, and were primarily due to changes in fair value of the derivative contracts.

The fair value on unsettled derivatives contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" and Note 7 and Note 8 for additional details about the Company's commodity derivatives. For information about the Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" under "Liquidity and Capital Resources" below.

Marketing and Other Revenues

Marketing revenues primarily represent third-party activities associated with the Company's long-term firm transportation contracts. The Company's current production is insufficient to fully utilize this capacity. To optimize its remaining capacity, the Company utilizes asset management agreements and various other marketing arrangements.

Sales of third-party natural

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gas are recorded as marketing revenues. Marketing and other revenues decreased by approximately $1 million or 8% to approximately $13 million for the year ended December 31, 2015, from approximately $14 million for the year ended December 31, 2014. The decrease was primarily due to lower marketing revenues principally due to a decrease in natural gas prices partially offset by higher helium sales revenue in the Hugoton Basin.

Marketing and other revenues increased by approximately $5 million or 53% to $14 million for the year ended December 31, 2014, from approximately $399,000 and $9 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, primarily due to an increase in natural gas prices during the first quarter of 2014.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased by approximately $120 million or 33% to approximately $245 million for the year ended December 31, 2015, from approximately $365 million for the year ended December 31, 2014. The decrease was primarily due to a decrease in steam costs caused by lower prices for natural gas used in steam generation, cost savings initiatives and lower costs as a result of the properties sold and exchanged during the third and fourth quarters of 2014. Lease operating expenses per BOE also decreased to $13.88 per BOE for the year ended December 31, 2015, from $19.30 per BOE for the year ended December 31, 2014.

Lease operating expenses increased by approximately $54 million or 17% to approximately $365 million for the year ended December 31, 2014, from approximately $15 million and $296 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively. Lease operating expenses increased primarily due to an increase in steam costs caused by a higher price and volume of natural gas used in steam generation. Lease operating expenses per BOE decreased to $19.30 per BOE for the year ended December 31, 2014, from $23.10 per BOE and $20.46 per BOE for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, primarily due to higher production volumes.

The following table sets forth steam information:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Average net volume of steam injected (Bbls/d)	279,182	251,726	229,909	201,617
Fuel gas cost per MMBtu (including transportation)	$2.62	$4.52	$4.58	$3.72
Estimated natural gas volumes consumed to produce steam (MMBtu/d)	98,979	90,320	82,275	69,792

Electricity Generation Expenses

Electricity generation expenses decreased by approximately $10 million or 36% to approximately $18 million for the year ended December 31, 2015, from approximately $28 million for the year ended December 31, 2014, primarily due to a decrease in fuel gas cost partially offset by an increase in fuel gas volumes purchased.

Electricity generation expenses increased by approximately $5 million or 19% to approximately $28 million for the year ended December 31, 2014, from approximately $1 million and $22 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, primarily due to increases in fuel gas cost and fuel gas volumes purchased.

Transportation Expenses

Transportation expenses increased by approximately $10 million or 25% to approximately $52 million for the year ended December 31, 2015, from approximately $42 million for the year ended December 31, 2014, primarily due to costs associated with Hugoton Basin properties acquired in the exchange with Exxon XTO on August 15, 2014. Transportation expenses decreased by approximately $8 million or 15% to approximately $42 million for the year ended December 31, 2014, from approximately $3 million and $47 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, primarily due to favorable marketing contract adjustments partially offset by higher expenses due to increased production volumes in the Uinta Basin.

Marketing Expenses

Marketing expenses primarily represent third-party activities associated with the Company’s long-term firm transportation contracts. The Company’s current production is insufficient to fully utilize its capacity. To optimize its remaining capacity, the Company utilizes asset management agreements and various other marketing arrangements. Purchases of third-party natural gas are recorded as marketing expenses. Marketing expenses decreased by approximately $4 million or 53% to approximately $4 million for the year ended December 31, 2015, from approximately $8 million for the year ended December 31, 2014, primarily due to a decrease in natural gas prices. Marketing expenses remained consistent at approximately $8 million for the year ended December 31, 2014, compared to approximately $376,000 and $8 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations. General and administrative expenses decreased by approximately $17 million or 16% to approximately $86 million for the year ended December 31, 2015, from approximately $103 million for the year ended December 31, 2014. The decrease was primarily due to lower costs allocated to the Company by Linn Operating, Inc. (“LOI”), a subsidiary of LINN Energy, as well as lower transition expenses and professional services expenses. General and administrative expenses per BOE also decreased to $4.87 per BOE for the year ended December 31, 2015, from $5.44 per BOE for the year ended December 31, 2014.

General and administrative expenses decreased by approximately $40 million or 28% to approximately $103 million for the year ended December 31, 2014, from approximately $20 million and $123 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively. The decrease was primarily due to lower share-based compensation allocated to the Company by LOI.

Exploration Costs

The Company recorded no exploration costs for the years ended December 31, 2015, and December 31, 2014, and for the period from December 17, 2013 through December 31, 2013. For the period from January 1, 2013 through December 16, 2013, the Company recorded exploration costs of approximately $24 million primarily related to the expiration of certain undeveloped leases in the Permian Basin.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization decreased by approximately $51 million or 17% to approximately $251 million for the year ended December 31, 2015, from approximately $302 million for the year ended December 31, 2014. The decrease was primarily due to lower rates as a result of the impairments recorded in the prior year and the first and third quarters of 2015 as well as lower total production volumes. Depreciation, depletion and amortization per BOE also decreased to $14.23 per BOE for the year ended December 31, 2015, from $16.01 per BOE for the year ended December 31, 2014. As a result of the uncertainty regarding the Company’s future commitment to capital, the Company reclassified all of its proved undeveloped reserves to unproved as of December 31, 2015, which may impact depletion in the future.

Depreciation, depletion and amortization increased by approximately $11 million or 4% to approximately $302 million for the year ended December 31, 2014, from approximately $11 million and $280 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per BOE decreased to $16.01 per BOE for the year ended December 31, 2014, from $16.26 per BOE and $19.35 per BOE for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively, primarily due to a lower oil and natural gas properties basis as a result of the adjustment made to record the properties at fair value on December 16, 2013, the acquisition date.

Impairment of Long-Lived Assets

The Company recorded the following noncash impairment charges (before and after tax) associated with proved oil and natural gas properties:

	Year Ended December 31,	
	2015	2014
	(in thousands)	
California operating area	$537,511	$22
Uinta Basin operating area	111,339	253,340
East Texas operating area	78,437	—
Piceance Basin operating area	55,344	—
	$782,631	$253,362

In addition, for the year ended December 31, 2015, the Company recorded noncash impairment charges (before and after tax) of approximately $71 million associated with unproved oil and natural gas properties in California.

The impairment charges in 2015 were due to a decline in commodity prices, changes in expected capital development and a decline in the Company’s estimates of proved reserves. The impairment charges in 2014 were due to a steep decline in commodity prices during the fourth quarter of 2014. The Company recorded no impairment charges for the periods from December 17, 2013 through December 31, 2013, or January 1, 2013 through December 16, 2013.

Subsequent to December 31, 2015, the prices of oil, natural gas and NGL have continued to be volatile. In the future, if forward price curves continue to decline, the Company may have additional impairments which could have a material impact on its results of operations.

Taxes, Other Than Income Taxes

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Severance taxes	$8,248	$25,113	$1,248	$17,514
Ad valorem taxes	44,980	54,819	882	23,995
California carbon allowances	17,363	17,751	—	15,554
Other	2	25	—	—
	$70,593	$97,708	$2,130	$57,063

Taxes, other than income taxes decreased by approximately $27 million or 28% for the year ended December 31, 2015, compared to the year ended December 31, 2014. Severance taxes, which are a function of revenues generated from production, decreased primarily due to lower oil, natural gas and NGL prices and lower production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, decreased primarily due to a lower estimated valuation on certain of the Company’s properties. California carbon allowances remained virtually unchanged.

Taxes, other than income taxes increased by approximately $39 million or 65% for the year ended December 31, 2014, compared to the year ended December 31, 2013. Severance taxes increased primarily due to higher production volumes and higher natural gas and NGL prices partially offset by lower oil prices. Ad valorem taxes increased primarily due to an

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adjustment to the taxable property basis in California in connection with the LINN Energy transaction. California carbon allowances increased primarily due to an increase in estimated emissions for which credits are needed.

(Gains) Losses on Sale of Assets and Other, Net

During the year ended December 31, 2014, the Company recorded the following net losses on the divestiture and exchanges of properties:

- Net loss of approximately $50 million, including costs to sell of approximately $2 million, on the Permian Basin Assets Sale;
- Net loss of approximately $30 million on the noncash exchange of a portion of its Permian Basin properties to ExxonMobil for properties in California's South Belridge Field; and
- Net loss of approximately $34 million on the noncash exchange of a portion of its Permian Basin properties to Exxon XTO for properties in the Hugoton Basin.

See Note 2 for additional details of the divestiture and exchanges of properties.

Other Income and (Expenses)

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Interest expense, net of amounts capitalized	$(85,818)	$(87,948)	$(3,963)	$(96,127)
Gain on extinguishment of debt	11,209	—	—	—
Other, net	(3,261)	(1,043)	(28)	51
	$(77,870)	$(88,991)	$(3,991)	$(96,076)

Other income and (expenses) decreased by approximately $11 million for the year ended December 31, 2015, compared to the year ended December 31, 2014. Interest expense decreased primarily due to lower outstanding debt during the period, partially offset by lower premium amortization related to the repayment of the June 2014 senior notes in May 2014 and a decrease in capitalized interest. In addition, for the year ended December 31, 2015, the Company recorded a gain on extinguishment of debt of approximately $11 million as a result of the repurchases of a portion its senior notes.

Other income and (expenses) decreased by approximately $11 million for the year ended December 31, 2014, compared to the year ended December 31, 2013. Interest expense decreased primarily due to the amortization of premiums related to the Company's debt being recorded at fair value on December 16, 2013, the acquisition date, partially offset by higher outstanding debt during the period.

See "Debt" under "Liquidity and Capital Resources" below for additional details.

Income Tax Expense (Benefit)

Effective December 16, 2013, the date of the LINN Energy transaction, the Company became 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 Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company. Prior to the LINN Energy transaction, the Company was a Subchapter C-corporation subject to federal and state income taxes (see Note 4). The Company recognized an income tax benefit of approximately $68,000 for the year ended December 31, 2015, compared to income tax expense of approximately $69,000 and $65 million for the year ended December 31, 2014, and for the period from January 1, 2013 through December 16, 2013, respectively. The income tax benefit in 2015 was primarily due to a decrease in state income tax expense resulting from changes in the Company's operations compared to 2014. The decrease in income tax expense in 2014 was primarily due to the Company's conversion from a Subchapter C-corporation to a limited liability company in connection with the LINN Energy transaction. The Company's effective tax rate was zero for the years ended December 31, 2015, and December 31, 2014, and for the period from December 17, 2013 through December 31, 2013, as the Company is a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of Texas. The Company's effective tax rate for the period from January 1, 2013 through December 16, 2013 was 41%. The Company recorded no income tax expense (benefit) for the period from December 17, 2013 through December 31, 2013.

Net Income (Loss)

Net income decreased by approximately $1.0 billion to a net loss of approximately $1.0 billion for the year ended December 31, 2015, from net income of approximately $23 million for the year ended December 31, 2014. The decrease was primarily due to lower production revenues and higher impairment charges, partially offset by lower other expenses.

Net income decreased by approximately $50 million or 69% to net income of approximately $23 million for the year ended December 31, 2014, from a net loss of approximately $20 million and net income of approximately $93 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively. The decrease was primarily due to higher impairment charges and other expenses, including interest, partially offset by higher production revenues and higher gains on oil and natural gas derivatives.

Liquidity and Capital Resources

The Company's liquidity outlook has changed since the third quarter of 2015 due to continued low commodity prices. The significant risks and uncertainties described under "Executive Overview" raise substantial doubt about the Company's ability to continue as a going concern. The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern.

The Company's Credit Facility contains the requirement to deliver audited financial statements without a going concern or like qualification or exception. Consequently, as of the filing date, March 28, 2016, the Company is in default under the Credit Facility. If the Company is unable to obtain a waiver or other suitable relief from the lenders under the Credit Facility prior to the expiration of the 30 day grace period, an Event of Default will result and the lenders holding a majority of the commitments under the Credit Facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. If the Company is unable to obtain a waiver from or otherwise reach an agreement with the lenders under the Credit Facility and the indebtedness under the Credit Facility is accelerated, then an Event of Default under the Company's senior notes would occur, which, if it continues beyond any applicable cure periods, would, to the extent the applicable lenders so elect, result in the acceleration of those obligations.

Furthermore, the Company has decided to defer making an interest payment totaling approximately $18 million due March 15, 2016, on the Company's senior notes due September 2022, which resulted in the Company being in default under these senior notes. The indenture governing the notes permits the Company a 30 day grace period to make the interest payments. If the Company fails to make the interest payments within the grace period, or is otherwise unable to obtain a waiver or suitable relief from the holders of these senior notes, an Event of Default will result and if the trustee or noteholders holding at least 25% in the aggregate outstanding principal amount of the notes so elect would accelerate the notes causing them to be immediately due and payable.

An Event of Default under any of the indentures governing the senior notes triggers a cross-default under the Credit Facility and, as discussed above, if the applicable lenders so elect would result in acceleration under the Credit Facility. In addition, as discussed above, an acceleration of the obligations under the Credit Facility, if the applicable lenders so elect, would result in cross-acceleration under the senior notes.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If the Company is unable to reach an agreement with its creditors prior to any of the above described accelerations, the Company could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

The Company is currently in discussions with various stakeholders and is pursuing or considering a number of actions including: (i) obtaining additional sources of capital from asset sales, private issuances of equity or equity-linked securities, debt for equity swaps, or any combination thereof; (ii) pursuing in- and out-of-court restructuring transactions; (iii) obtaining waivers or amendments from its lenders; and (iv) continuing to minimize its capital expenditures, reduce costs and maximize cash flows from operations. There can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed.

The Company has utilized funds from debt offerings, borrowings under its Credit Facility, net cash provided by operating activities and funding from LINN Energy for capital resources and liquidity. Historically, the primary use of capital has been for the development of oil and natural gas properties. For the year ended December 31, 2015, the Company's total capital expenditures were approximately $152 million. LINN Energy continually evaluates the capital needs of the Company along with those of its other operating areas. LINN Energy establishes a capital plan each calendar year for all of its operations based on development opportunities and the expected cash flow from operations for that year. The capital plan may be revised during the year as a result of drilling outcomes or significant changes in cash flows. To the extent net cash provided by operating activities is higher or lower than currently anticipated, LINN Energy may adjust the Company's capital plan accordingly or adjust borrowings under the Company's Credit Facility, as needed. However, at January 31, 2016, the Company had less than $1 million of available borrowing capacity under its Credit Facility.

LINN Energy's credit facility contains certain restrictions on its ability to contribute capital or loan funds to Berry. Based on current estimates, including the low commodity price environment, the Company expects to generate a cash shortfall in 2016. Historically, LINN Energy has contributed capital to Berry to fund capital expenditures and other cash shortfalls but LINN Energy is not obligated to continue to provide funding to Berry, nor is LINN Energy a guarantor of any of Berry's indebtedness.

In October 2015, the Company entered into an amendment to its Credit Facility. See Note 3 for additional details.

The spring 2015 semi-annual borrowing base redetermination of the Company's Credit Facility was completed in May 2015, and as a result of lower commodity prices, the borrowing base under the Credit Facility decreased from $1.4 billion to $1.2 billion. The fall 2015 semi-annual redetermination was completed in October 2015 and the borrowing base under the Credit Facility decreased from $1.2 billion to $900 million. In connection with the reduction in Berry's borrowing base in October 2015, Berry repaid $300 million of borrowings outstanding under the Credit Facility using the cash received from the settlement of its advance and capital contributions made by LINN Energy. Continued low commodity prices, reductions in the Company's capital budget and the resulting reserve write-downs are expected to adversely impact future redeterminations.

In connection with the reduction in Berry's borrowing base in May 2015, LINN Energy contributed $250 million to Berry to post as restricted cash with Berry's lenders. As directed by LINN Energy, the $250 million was deposited on Berry's behalf in a security account with the administrative agent subject to a security control agreement. Berry's ability to withdraw funds from this account is subject to a concurrent reduction of the borrowing base under the Credit Facility or lender's consent in connection with a redetermination of such borrowing base. The $250 million may be used to satisfy obligations under the Credit Facility or, subject to restrictions in the indentures governing Berry's senior notes, may be returned to LINN Energy in the future.

LINN Energy continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company's future success in growing reserves and production volumes will be highly dependent on the capital resources available and its success in adding reserves from its drilling program. The Company's Credit Facility and indentures governing its senior notes impose certain restrictions on the Company's ability to obtain additional debt financing. The Company does not intend to obtain additional borrowing capacity under its Credit Facility or access the capital markets separately from LINN Energy. The Company intends to finance its operations, including its future capital expenditures, with net cash provided by operating activities and funding from LINN Energy, to the extent LINN Energy elects to provide such funding. See Item 1A. "Risk Factors," for additional information about liquidity risks, the risk that the Company may be unable to repay or refinance its existing and future debt as it becomes due, and other risks that could affect the Company.

Any cash generated by the Company is currently being used by the Company to fund its activities. To the extent that the Company generates cash in excess of its needs and determines to distribute such amounts to LINN Energy, the indentures governing the Company's senior notes limit the amount it may distribute to LINN Energy to the amount available under a "restricted payments basket," and the Company may not distribute any such amounts unless it is permitted by the indentures to incur additional debt pursuant to the consolidated coverage ratio test set forth in the Company’s indentures. The Company’s restricted payments basket was approximately $529 million at December 31, 2015, and may be increased in accordance with the terms of the Company’s indentures by, among other things, 50% of the Company’s future net income, reductions in its indebtedness and restricted investments, and future capital contributions.

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Statements of Cash Flows
The following is a comparative cash flow summary:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Net cash:				
Provided by operating activities	$122,518	$583,480	$56,678	$442,968
Provided by (used in) investing activities	101,368	(516,222)	(17,478)	(586,982)
Provided by (used in) financing activities	(224,449)	(116,713)	(439,272)	599,687
Net increase (decrease) in cash and cash equivalents	$(563)	$(49,455)	$(400,072)	$455,673

Operating Activities
Cash provided by operating activities for the year ended December 31, 2015, was approximately $123 million, compared to approximately $583 million for the year ended December 31, 2014. The decrease was primarily due to lower production related revenues principally due to lower commodity prices partially offset by higher cash settlements on derivatives.
Cash provided by operating activities for the year ended December 31, 2014, was approximately $583 million, compared to approximately $57 million and $443 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively. The increase was primarily due to higher production related revenues principally due to increased oil and natural gas production volumes and higher natural gas and NGL prices, as well as higher cash settlements on derivatives, partially offset by higher expenses.
Investing Activities
The following provides a comparative summary of cash flow from investing activities:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Cash flow from investing activities:				
Capital expenditures	$(50,374)	$(523,889)	$(17,478)	$(598,512)
Settlement of advance to affiliate	129,217	—	—	—
Proceeds from sale of properties and equipment and other	22,525	7,667	—	11,530
	$101,368	$(516,222)	$(17,478)	$(586,982)

The primary use of cash in investing activities is for the development of the Company's oil and natural gas properties. Capital expenditures decreased in 2015 and 2014 primarily due to lower spending on development activities. For the years ended December 31, 2015, and December 31, 2014, LINN Energy spent approximately $165 million and $58 million, respectively, of capital expenditures in respect of Berry's operations (see Note 1 and Note 12). In addition, on September 30, 2015, LINN Energy repaid in full its remaining advance of approximately $129 million to Berry.
Financing Activities
Cash used in financing activities of approximately $224 million for the year ended December 31, 2015, was primarily related to the repayment of a portion of the borrowings outstanding under the Company's Credit Facility, cash distributions to LINN Energy and repurchases of a portion of its senior notes, partially offset by capital contributions made by LINN Energy. In addition, in May 2015, LINN Energy made a capital contribution of $250 million to Berry

which was deposited on Berry’s behalf and posted as restricted cash with Berry’s lenders in connection with the reduction in its borrowing base (see Note 3).

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Cash used in financing activities of approximately $117 million for the year ended December 31, 2014, was primarily related to cash distributions made to LINN Energy during the year.

Cash used in financing activities for the period from December 17, 2013 through December 31, 2013, includes a distribution of $435 million to LINN Energy following the closing of the LINN Energy transaction. Cash provided by financing activities for the period from January 1, 2013 through December 16, 2013, included net borrowings of approximately $610 million under the Company's Credit Facility.

Debt

During the year ended December 31, 2015, the Company repurchased at a discount, on the open market and through a privately negotiated transaction, approximately $65 million of its outstanding senior notes including approximately $39 million of its 6.75% senior notes due November 2020 and approximately $26 million of its 6.375% senior notes due September 2022.

On May 30, 2014, in accordance with the provisions of the indenture related to its June 2014 Senior Notes, the Company paid in full the remaining outstanding principal amount of approximately $205 million using a cash capital contribution from LINN Energy (see Note 12).

In February 2014, in accordance with the indentures related to the senior notes, the Company repurchased through cash tender offers $321,000, $30,000 and $837,000 of its June 2014 Senior Notes, November 2020 Senior Notes and September 2022 Senior Notes, respectively.

The Company's Credit Facility had a borrowing base of $900 million, subject to lender commitments, as of January 31, 2016. At January 31, 2016, lender commitments under the facility were also $900 million but there was less than $1 million of available borrowing capacity, including outstanding letters of credit. For additional information related to the Company's outstanding debt, see Note 3.

Financial Covenants

The Credit Facility, as amended in October 2015, contains requirements and financial covenants, among others, to maintain: 1) a ratio of Adjusted EBITDAX to Interest Expense (as each term is defined in the Credit Facility) ("Interest Coverage Ratio") for the preceding four quarters of greater than 2.5 to 1.0 through September 30, 2015, 2.0 to 1.0 currently, 2.25 to 1.0 from March 31, 2017 through June 30, 2017, and returning to 2.5 to 1.0 thereafter, and 2) a ratio of Current Assets to Current Liabilities (as each term is defined in the Credit Facility) ("Current Ratio") as of the last day of any fiscal quarter of greater than 1.0 to 1.0. The Interest Coverage Ratio is intended as a measure of the Company's ability to make interest payments on its outstanding indebtedness and the Current Ratio is intended as a measure of the Company's solvency. The Company is required to demonstrate compliance with each of these ratios on a quarterly basis. The following represents the calculations of the Interest Coverage Ratio and the Current Ratio as presented to the lenders under the Credit Facility:

	At or for the Quarter Ended				Twelve Months Ended
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015	December 31, 2015
Interest Coverage Ratio	1.7	2.6	2.2	1.6	2.0
Current Ratio [1]	0.6	0.5	2.0	0.4	0.4
Current Ratio (consolidated) [1]	3.2	2.9	2.6	1.7	1.7

(1) The Credit Facility allows Berry to demonstrate its compliance with the Current Ratio financial covenant on a consolidated basis with LINN Energy for up to three quarters of each calendar year.

The Company has included disclosure of the Interest Coverage Ratio for the twelve months ended December 31, 2015, and the Current Ratio as of December 31, 2015, to demonstrate its compliance for the quarter ended December 31, 2015, as well as the Interest Coverage Ratio for each of the preceding four quarters on an individual basis (rather than on a last twelve months basis) and the Current Ratio as of the end of each of the preceding four quarters to provide investors with trend information about the Company's ongoing compliance with these financial covenants. If the Company fails to demonstrate

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

compliance with either or both of the Interest Coverage Ratio or the Current Ratio as of the end of the quarter and such failure continues beyond applicable cure periods, an event of default would occur and the Company would be unable to make additional borrowings and outstanding indebtedness may be accelerated.

See "Going Concern Uncertainty" above under "Executive Overview" for information about the impact to the Company's compliance with its covenants resulting from the auditors' opinion issued in connection with the financial statements that includes a going concern explanation.

Contingencies

See Item 3. "Legal Proceedings" for information regarding legal proceedings that the Company is party to and any contingencies related to these legal proceedings.

Commitments and Contractual Obligations

The following is a summary of the Company's commitments and contractual obligations as of December 31, 2015:

Contractual Obligations	Payments Due Total	2016	2017 – 2018	2019 – 2020	2021 and Beyond
	(in thousands)				
Debt obligations:					
Credit Facility (1)	$873,175	$873,175	$—	$—	$—
Senior notes	833,800	—	—	261,100	572,700
Interest (2)	433,647	81,814	163,628	115,186	73,019
Operating lease obligations:					
Office, property and equipment leases	9,377	3,710	3,513	2,154	—
Other:					
Commodity derivatives	2,241	2,241	—	—	—
Asset retirement obligations	137,563	2,548	5,227	8,713	121,075
Firm natural gas transportation contracts (3)	146,981	33,446	57,389	41,651	14,495
Other	2,442	2,442	—	—	—
	$2,439,226	$999,376	$229,757	$428,804	$781,289

(1) Due to existing and anticipated covenant violations, the Company's Credit Facility was classified as current at December 31, 2015.

(2) Represents interest on the Credit Facility computed at 3.17% through contractual maturity in April 2019. Interest on the November 2020 senior notes and September 2022 senior notes computed at fixed rates of 6.75% and 6.375%, respectively.

(3) The Company enters into certain firm commitments to transport natural gas production to market and to transport natural gas for use in the Company's cogeneration and conventional steam generation facilities. The remaining terms of these contracts range from approximately two to eight years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value. The Company's counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company's oil, natural gas and NGL reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations is based on the financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these financial statements requires management of the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors that are believed to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. Actual results may differ from these estimates and assumptions used in the preparation of the financial statements.

Below are expanded discussions of the Company's more significant accounting policies, estimates and judgments, i.e., those that reflect more significant estimates and assumptions used in the preparation of its financial statements. See Note 1 for details about additional accounting policies and estimates made by Company management.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1.

Oil and Natural Gas Reserves

Proved reserves are based on the quantities of oil, natural gas and NGL that 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. The independent engineering firm, DeGolyer and MacNaughton, prepared a reserve and economic evaluation of all of the Company properties on a well-by-well basis as of December 31, 2015, and the reserve estimates reported herein were prepared by DeGolyer and MacNaughton. The reserve estimates were reviewed and approved by LINN Energy's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer.

Reserves and their relation to estimated future net cash flows impact the Company's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. 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 the Company. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years.

The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. In addition, reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas and NGL eventually recovered. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data" and see also Item 1. "Business."

Oil and Natural Gas Properties

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold 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 currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of approximately $2 million, $6 million, $41,000 and $6 million for the years ended December 31, 2015, and December 31, 2014, and for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. 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 market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are the most sensitive and subject to change. The underlying commodity prices embedded in the Company’s estimated cash flows are the product of a process that begins with New York Mercantile Exchange forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices.

Based on the analysis described above, for the years ended December 31, 2015, and December 31, 2014, the Company recorded noncash impairment charges (before and after tax) of approximately $783 million and $253 million, respectively, associated with proved oil and natural gas properties. 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 are included in “impairment of long-lived assets” on the statements of operations. The Company recorded no impairment charges for proved properties for the periods from December 17, 2013 through December 31, 2013, or January 1, 2013 through December 16, 2013.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past.

Based primarily on a decline in commodity prices and changes in expected capital development, for the year ended December 31, 2015, the Company recorded noncash impairment charges (before and after tax) of approximately $71 million associated with unproved oil and natural gas properties. 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 the statement of operations. The Company recorded no impairment charges for unproved properties for the year ended December 31, 2014, or for the periods from December 17, 2013 through December 31, 2013, or January 1, 2013 through December 16, 2013.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The Company recorded no exploration costs during the years ended December 31, 2015, and December 31, 2014, or for the period from December 17, 2013 through December 31, 2013. The Company recorded noncash leasehold impairment expenses related to unproved properties of approximately $16 million for the period from January 1, 2013 through December 16, 2013, which is included in “exploration costs” on the statement of operations.

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Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

Revenue Recognition
Sales of oil, natural gas and NGL are recognized when the product has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. In addition, the Company engages in the purchase, gathering and transportation of third-party natural gas and subsequently markets such natural gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing revenues and marketing expenses.
Derivative Instruments
Historically, the Company has hedged a portion of its forecasted production to reduce exposure to fluctuations in oil and natural gas prices. The Company also, from time to time, has entered into derivative contracts for a portion of its natural gas consumption. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company’s ability to effectively hedge its NGL production. The Company has also hedged its exposure to natural gas differentials in certain operating areas but does not currently hedge exposure to oil differentials. By removing a portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.
The Company has historically entered into commodity hedging transactions primarily in the form of swap contracts, collars and three-way collars, and may enter into put option contracts in the future. The Company does not enter into derivative contracts for trading purposes.
A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date.
Derivative instruments are recorded at fair value and included on the balance sheets as assets or liabilities. The Company did not designate any of its contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company determines the fair value of its 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. Company management validates 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. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads are applied to the Company’s commodity derivatives. See Note 7 and Note 8 for additional details about the Company’s derivative financial instruments.
Acquisition Accounting
The Company accounts for business combinations under the acquisition method of accounting (see Note 2). Accordingly, the Company recognizes amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Transaction and integration costs associated with business combinations are expensed as incurred. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill while any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain.
The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would

use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves; (ii) future operating and development costs;

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(iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable and possible reserves are reduced by additional risk-weighting factors. In addition, when appropriate, the Company reviews comparable purchases and sales of oil and natural gas properties within the same regions, and uses that data as a proxy for fair market value; i.e., the amount a willing buyer and seller would enter into in exchange for such properties.

While the estimated fair values of the assets acquired and liabilities assumed have no effect on cash flow, they can have an effect on future results of operations. Generally, higher fair values assigned to oil and natural gas properties result in higher future depreciation, depletion and amortization expense, which results in decreased future net income. Also, a higher fair value assigned to oil and natural gas properties, based on higher future estimates of commodity prices, could increase the likelihood of impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. The recording of impairment expense has no effect on cash flow but results in a decrease in net income for the period in which the impairment is recorded.

Electricity Cost Allocation

The Company's investment in its cogeneration facilities has been for the express purpose of lowering steam costs in its heavy oil operations in California and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. The Company allocates steam costs to lease operating expenses based on the conversion efficiency (of fuel to electricity and steam) of the cogeneration facilities plus certain direct costs in producing steam. A portion of the costs of operating the cogeneration facilities is also allocated to depreciation, depletion and amortization.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in commodity prices and interest rates. These risks can affect the Company's business, financial condition, operating results and cash flows. See below for quantitative and qualitative information about these risks. The following should be read in conjunction with the financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The reference to a "Note" herein refers to the accompanying Notes to Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Commodity Price Risk

The Company's most significant market risk relates to prices of oil, natural gas and NGL. The Company expects commodity prices to remain volatile and unpredictable. As commodity prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, future declines in commodity prices may result in noncash write-downs of the Company's carrying amounts of its assets.

Historically, the Company has hedged a portion of its forecasted production to reduce exposure to fluctuations in oil and natural gas prices. The Company also, from time to time, has entered into derivative contracts for a portion of its natural gas consumption. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company's ability to effectively hedge its NGL production. The Company has also hedged its exposure to natural gas differentials in certain operating areas but does not currently hedge exposure to oil differentials. By removing a portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

The Company has historically entered into commodity hedging transactions primarily in the form of swap contracts, collars and three-way collars, and may enter into put option contracts in the future. The Company does not enter into derivative contracts for trading purposes.

The appropriate level of production to be hedged is an ongoing consideration and is based on a variety of factors, including current and future expected commodity market prices, cost and availability of put option contracts, the level of LINN Energy's acquisition activity, the Company's overall risk profile, including leverage and size and scale considerations, and an actively traded market for hedging transactions, including counterparty willingness to enter into derivative contracts with the Company. In addition, when commodity prices are depressed and forward commodity price curves are flat or in backwardation, the Company may determine that the benefit of hedging its anticipated production at these levels is outweighed by its resultant inability to obtain higher revenues for its production if commodity prices recover during the duration of the contracts. As a result, the appropriate percentage of production volumes to be hedged may change over time.

As of December 31, 2015, the Company had 44,652 MMMBtu of natural gas basis swaps for 2016, and no derivative contracts for years subsequent to 2016. See Note 7 for details about the Company's derivative instruments.

Interest Rate Risk

At December 31, 2015, the Company had debt outstanding under its credit facility of approximately $873 million which incurred interest at floating rates (see Note 3). A 1% increase in the London Interbank Offered Rate ("LIBOR") would result in an estimated $9 million increase in annual interest expense.

At December 31, 2014, the Company had debt outstanding under its credit facility of approximately $1.2 billion which incurred interest at floating rates. A 1% increase in the LIBOR would result in an estimated $12 million increase in annual interest expense.

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Item 8. Financial Statements and Supplementary Data

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MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

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

As of December 31, 2015, our management assessed the effectiveness of the Company’s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control – Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2015, based on those criteria.

/s/ Berry Petroleum Company, LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Linn Energy, LLC as indirect parent of Berry Petroleum Company, LLC:

We have audited the accompanying balance sheets of Berry Petroleum Company, LLC (Successor) as of December 31, 2015 and 2014, and the related statements of operations, member's equity, and cash flows for the years ended December 31, 2015 and 2014 and for the period from December 17, 2013 through December 31, 2013 (Successor period). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the Successor financial statements referred to above present fairly, in all material respects, the financial position of Berry Petroleum Company, LLC as of December 31, 2015 and 2014, and the results of its operations and its cash flows for the Successor period, in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, because of continued low commodity prices, the Company has suffered recurring losses from operations and is in violation of a restrictive covenant and expects to be in violation of financial covenants contained in its credit facility that would accelerate the maturity of the outstanding indebtedness making it immediately due and payable. The Company does not have sufficient liquidity to meet the accelerated debt service requirements and has disclosed it deferred making an interest payment due March 15, 2016, on its senior notes due September 2022. These issues raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in note 2 to the financial statements, effective December 16, 2013, LinnCo, LLC acquired all of the outstanding shares of Berry Petroleum Company in a business combination accounted for as a purchase. As a result of the acquisition, the financial information for the periods after the acquisition is presented on a different cost basis than that for the periods before the acquisition and, therefore, is not comparable.

/s/ KPMG LLP

Houston, Texas
March 28, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To Linn Energy, LLC as indirect parent of Berry Petroleum Company, LLC:

In our opinion, the accompanying statements of operations, shareholders' equity and cash flows for the period from January 1, 2013 through December 16, 2013, present fairly, in all material respects, the results of operations and cash flows of Berry Petroleum Company, LLC (Predecessor) for the period from January 1, 2013 through December 16, 2013, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in note 2 to the financial statements, effective December 16, 2013, LinnCo, LLC acquired all of the outstanding shares of Berry Petroleum Company in a business combination accounted for as a purchase.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
March 31, 2014

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BERRY PETROLEUM COMPANY, LLC
BALANCE SHEETS
(in thousands)

	December 31, 2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$1,023	$1,586
Accounts receivable – trade, net	46,053	100,359
Derivative instruments	13,218	43,694
Other current assets	20,897	59,259
Total current assets	81,191	204,898
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	5,011,061	4,872,059
Less accumulated depletion and amortization	(1,596,165)	(525,007)
	3,414,896	4,347,052
Other property and equipment	111,495	115,999
Less accumulated depreciation	(12,522)	(8,452)
	98,973	107,547
Advance to affiliate	—	293,627
Restricted cash	250,359	125
Other noncurrent assets	16,057	14,159
	266,416	307,911
Total noncurrent assets	3,780,285	4,762,510
Total assets	$3,861,476	$4,967,408
LIABILITIES AND MEMBER’S EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$125,748	$242,350
Derivative instruments	2,241	—
Current portion of long-term debt	873,175	—
Other accrued liabilities	16,736	19,087
Total current liabilities	1,017,900	261,437
Noncurrent liabilities:		
Long-term debt, net	845,368	2,086,952
Other noncurrent liabilities	212,049	200,015
Total noncurrent liabilities	1,057,417	2,286,967
Commitments and contingencies (Note 11)		
Member’s equity:		
Additional paid-in capital	2,798,713	2,416,381
Accumulated income (deficit)	(1,012,554)	2,623
	1,786,159	2,419,004
Total liabilities and member’s equity	$3,861,476	$4,967,408

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

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BERRY PETROLEUM COMPANY, LLC
STATEMENTS OF OPERATIONS
(in thousands)

	Successor Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	Predecessor January 1, 2013 through December 16, 2013
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$575,031	$1,298,402	$50,324	$1,103,245
Electricity sales	24,544	40,022	1,444	33,992
Gains (losses) on oil and natural gas derivatives	29,175	78,784	(5,049)	(34,711)
Marketing revenues	5,709	10,889	399	7,827
Other revenues	7,195	3,192	—	949
	641,654	1,431,289	47,118	1,111,302
Expenses:				
Lease operating expenses	245,155	364,540	15,410	295,811
Electricity generation expenses	18,057	28,171	1,257	22,485
Transportation expenses	52,160	41,842	2,576	46,774
Marketing expenses	3,809	8,084	376	7,593
General and administrative expenses	85,993	102,787	20,298	122,991
Exploration costs	—	—	—	24,048
Depreciation, depletion and amortization	251,371	302,353	10,845	279,757
Impairment of long-lived assets	853,810	253,362	—	—
Taxes, other than income taxes	70,593	97,708	2,130	57,063
(Gains) losses on sale of assets and other, net	(1,919)	120,786	10,208	(23)
	1,579,029	1,319,633	63,100	856,499
Other income and (expenses):				
Interest expense, net of amounts capitalized	(85,818)	(87,948)	(3,963)	(96,127)
Gain on extinguishment of debt	11,209	—	—	—
Other, net	(3,261)	(1,043)	(28)	51
	(77,870)	(88,991)	(3,991)	(96,076)
Income (loss) before income taxes	(1,015,245)	22,665	(19,973)	158,727
Income tax expense (benefit)	(68)	69	—	65,280
Net income (loss)	$(1,015,177)	$22,596	$(19,973)	$93,447

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

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BERRY PETROLEUM COMPANY, LLC
STATEMENT OF SHAREHOLDERS' EQUITY (PREDECESSOR)
(in thousands)

	Class A	Class B	Additional Paid-In Capital	Accumulated Income	Total Shareholders' Equity
December 31, 2012	$524	$18	$364,710	$649,539	$1,014,791
Stock options and restricted stock issued	3	—	727	—	730
Stock-based compensation expense	—	—	12,576	—	12,576
Income tax effect of stock option exercises	—	—	2,345	—	2,345
Dividends ($0.32 per share)	—	—	—	(17,612)	(17,612)
Net income	—	—	—	93,447	93,447
December 16, 2013 [1]	$527	$18	$380,358	$725,374	$1,106,277

STATEMENTS OF MEMBER'S EQUITY (SUCCESSOR)
(in thousands)

	Additional Paid-In Capital	Accumulated Income (Deficit)	Total Member's Equity
December 17, 2013 [1]	$2,781,888	$—	$2,781,888
Distribution to affiliate	(435,000)	—	(435,000)
Transfer of derivative liability from affiliate	(31,428)	—	(31,428)
Net loss	—	(19,973)	(19,973)
December 31, 2013	2,315,460	(19,973)	2,295,487
Capital contribution from affiliate	220,000	—	220,000
Distributions to affiliate	(119,079)	—	(119,079)
Net income	—	22,596	22,596
December 31, 2014	2,416,381	2,623	2,419,004
Capital contributions from affiliate	471,278	—	471,278
Distributions to affiliate	(88,946)	—	(88,946)
Net loss	—	(1,015,177)	(1,015,177)
December 31, 2015	$2,798,713	$(1,012,554)	$1,786,159

(1) The differences in equity balances at December 16, 2013, and December 17, 2013, are due to the application of pushdown accounting reflecting the LINN Energy transaction.

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

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BERRY PETROLEUM COMPANY, LLC
STATEMENTS OF CASH FLOWS
(in thousands)

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Cash flow from operating activities:				
Net income (loss)	$(1,015,177)	$22,596	$(19,973)	$93,447
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	251,371	302,353	10,845	279,757
Impairment of long-lived assets	853,810	253,362	—	—
Stock-based compensation expense	—	—	—	12,576
Gain on extinguishment of debt	(11,209)	—	—	—
Amortization and write-off of deferred financing fees	3,750	(4,913)	(615)	6,685
Change in book overdraft	—	—	—	(14,885)
(Gains) losses on sale of assets and other, net	(961)	111,374	—	14,907
Deferred income taxes	(68)	69	—	76,644
Derivatives activities:				
Total (gains) losses	(36,068)	(78,784)	5,049	34,711
Cash settlements	68,770	6,738	—	182
Cash settlements on canceled derivatives	—	12,281	—	—
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable – trade, net	59,941	16,483	71,434	(97,653)
(Increase) decrease in other assets	18,724	(15,949)	10,613	996
Increase (decrease) in accounts payable and accrued expenses	(62,755)	(3,719)	(8,078)	28,187
Increase (decrease) in other liabilities	(7,610)	(38,411)	(12,597)	7,414
Net cash provided by operating activities	122,518	583,480	56,678	442,968
Cash flow from investing activities:				
Property acquisitions	—	—	—	(3,933)
Development of oil and natural gas properties	(32,633)	(512,419)	(17,478)	(588,829)
Purchases of other property and equipment	(17,741)	(11,470)	—	(5,750)
Settlement of advance to affiliate	129,217	—	—	—
Proceeds from sale of properties and equipment and other	22,525	7,667	—	11,530
Net cash provided by (used in) investing activities	101,368	(516,222)	(17,478)	(586,982)
Cash flow from financing activities:				
Proceeds from borrowings	—	—	—	1,225,475
Repayments of debt	(355,418)	(206,124)	—	(615,200)

Dividends paid	—	—	(4,272)	(13,204)
Financing fees and other, net	(1,363)	(11,510)	—	(459)
Proceeds from stock option exercises	—	—	—	730
Capital contributions from affiliate	221,278	220,000	—	—
Distributions to affiliate	(88,946)	(119,079)	(435,000)	—
Excess tax benefit from stock-based compensation	—	—	—	2,345
Net cash provided by (used in) financing activities	(224,449)	(116,713)	(439,272)	599,687
Net increase (decrease) in cash and cash equivalents	(563)	(49,455)	(400,072)	455,673
Cash and cash equivalents:				
Beginning	1,586	51,041	451,113	312
Ending	$1,023	$1,586	$51,041	$455,985

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

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BERRY PETROLEUM COMPANY, LLC
NOTES TO FINANCIAL STATEMENTS

Note 1 – Basis of Presentation and Significant Accounting Policies

Nature of Business

Berry Petroleum Company, LLC (“Berry” or the “Company”) was formed as a Delaware limited liability company on December 16, 2013, and is an indirect wholly owned subsidiary of Linn Energy, LLC (“LINN Energy”) engaged in the production and development of oil and natural gas. The Company’s predecessor, Berry Petroleum Company, was publicly traded from 1987 until December 2013. On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between LINN Energy, LinnCo, LLC (“LinnCo”), an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and LINN Energy, under which LinnCo contributed Berry to LINN Energy in exchange for LINN Energy units (see Note 2). Linn Acquisition Company, LLC, a direct subsidiary of LINN Energy, is currently the Company’s sole member.

The Company’s properties are located in the United States (“U.S.”), in California (San Joaquin Valley and Los Angeles basins), Kansas and the Oklahoma Panhandle (Hugoton Basin), Utah (Uinta Basin), Colorado (Piceance Basin) and east Texas. In August and November of 2014, the Company divested all of its properties located in the Permian Basin.

The operations of the Company are governed by the provisions of a limited liability company agreement executed by its member. Pursuant to applicable provisions of the Delaware Limited Liability Company Act (“Delaware Act”) and the Limited Liability Company Agreement of Berry Petroleum Company, LLC (“LLC Agreement”), the member has no liability for the debts, obligations and liabilities of the Company, except as expressly required in the LLC Agreement or the Delaware Act. The Company will remain in existence unless and until dissolved in accordance with the terms of the LLC Agreement.

Going Concern Uncertainty

The Company’s liquidity outlook has changed since the third quarter of 2015 due to continued low commodity prices. In addition, the Company’s Credit Facility is subject to scheduled redeterminations of its borrowing base, semi-annually in April and October, based primarily on reserve reports using lender commodity price expectations at such time. Continued low commodity prices, reductions in the Company’s capital budget and the resulting reserve write-downs are expected to adversely impact the upcoming April redetermination and will likely have a significant negative impact on the Company’s liquidity.

As a result of these and other factors, the following issues have adversely impacted the Company’s ability to continue as a going concern:

- the Company’s ability to comply with financial covenants and ratios in its Credit Facility and indentures has been affected by continued low commodity prices. Absent a waiver or amendment, failure to meet these covenants and ratios would result in a default and, to the extent the applicable lenders so elect, an acceleration of the Company’s existing indebtedness, causing such debt of approximately $873 million to be immediately due and payable. Based on the Company’s current estimates and expectations for commodity prices in 2016, the Company does not expect to remain in compliance with all of the restrictive covenants contained in its Credit Facility throughout 2016 unless those requirements are waived or amended. The Company does not currently have adequate liquidity to repay all of its outstanding debt in full if such debt were accelerated;
- because the Credit Facility is effectively fully drawn, any reduction of the borrowing base under the Company’s Credit Facility would require mandatory prepayments to the extent existing indebtedness exceeds the new borrowing base. The Company may not have sufficient cash on hand to be able to make any such mandatory prepayments; and
- the Company’s ability to make interest payments as they become due and repay indebtedness upon maturities (whether under existing terms or as a result of acceleration) is impacted by the Company’s liquidity. As of February 29, 2016, there was less than $1 million of available borrowing capacity under the Credit Facility.

The Company’s Credit Facility contains the requirement to deliver audited financial statements without a going concern or like qualification or exception. Consequently, as of the filing date, March 28, 2016, the Company is in default under the Credit Facility. If the Company is unable to obtain a waiver or other suitable relief from the lenders under the Credit Facility prior to the expiration of the 30 day grace period, an Event of Default (as defined in the applicable agreements) will result

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and the lenders holding a majority of the commitments under the Credit Facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. If the Company is unable to obtain a waiver from or otherwise reach an agreement with the lenders under the Credit Facility and the indebtedness under the Credit Facility is accelerated, then an Event of Default under the Company's senior notes would occur, which, if it continues beyond any applicable cure periods, would, to the extent the applicable lenders so elect, result in the acceleration of those obligations.

Furthermore, the Company has decided to defer making an interest payment totaling approximately $18 million due March 15, 2016, on the Company's senior notes due September 2022, which resulted in the Company being in default under these senior notes. The indenture governing the notes permits the Company a 30 day grace period to make the interest payments. If the Company fails to make the interest payments within the grace period, or is otherwise unable to obtain a waiver or suitable relief from the holders of these senior notes, an Event of Default will result and if the trustee or noteholders holding at least 25% in the aggregate outstanding principal amount of the notes so elect would accelerate the notes causing them to be immediately due and payable.

An Event of Default under any of the indentures governing the senior notes triggers a cross-default under the Credit Facility and, as discussed above, if the applicable lenders so elect would result in acceleration under the Credit Facility. In addition, as discussed above, an acceleration of the obligations under the Credit Facility, if the applicable lenders so elect, would result in cross-acceleration under the senior notes.

See Note 3 for additional details about the Company's debt.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness (approximately $1.7 billion as of December 31, 2015), it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If the Company is unable to reach an agreement with its creditors prior to any of the above described accelerations, the Company could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

The significant risks and uncertainties described above raise substantial doubt about the Company's ability to continue as a going concern. The financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

The Company is currently in discussions with various stakeholders and is pursuing or considering a number of actions including: (i) obtaining additional sources of capital from asset sales, private issuances of equity or equity-linked securities, debt for equity swaps, or any combination thereof; (ii) pursuing in- and out-of-court restructuring transactions; (iii) obtaining waivers or amendments from its lenders; and (iv) continuing to minimize its capital expenditures, reduce costs and maximize cash flows from operations. There can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed.

Principles of Reporting

The Company presents its financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"). Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method.

The financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss), shareholders' or member's equity or cash flows.

Predecessor and Successor Reporting

The LINN Energy transaction was accounted for under the acquisition method of accounting. Under the acquisition method of accounting, LinnCo initially, and LINN Energy upon the contribution was treated as the accounting acquirer and the Company was treated as the acquired company for financial reporting purposes. As such, the assets and liabilities of the Company were provisionally recorded at their respective fair values as of the acquisition date.

Fair value adjustments related

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to the transaction have been pushed down to the Company, resulting in assets and liabilities of the Company being recorded at their fair values at December 16, 2013. See Note 2 for additional information regarding the LINN Energy transaction.

The Company's statements of operations subsequent to the transaction include depreciation, depletion and amortization expense on the Company's oil and natural gas properties, and other property and equipment balances resulting from the fair value adjustments made under the new basis of accounting. Certain other items of income and expense were also impacted. Therefore, the Company's financial information prior to the transaction is not comparable to its financial information subsequent to the transaction.

As a result of the impact of pushdown accounting, the financial statements and certain note presentations separate the Company's presentations into two distinct periods, the period before the consummation of the transaction (labeled predecessor) and the period after that date (labeled successor), to indicate the application of a different basis of accounting between the periods presented.

Use of Estimates

The preparation of the accompanying financial statements in conformity with GAAP requires management of the Company to make 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. The estimates that are particularly significant to the financial statements include estimates of the Company's reserves of oil, natural gas and natural gas liquids ("NGL"), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and 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 estimates and assumptions are adjusted when 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 estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Recently Issued Accounting Standards

In November 2015, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") that is intended to simplify the presentation of deferred taxes by requiring that all deferred taxes be presented as noncurrent. This ASU will be applied either prospectively or retrospectively as of the date of adoption and is effective for fiscal years beginning after December 15, 2016, and interim periods within those years (early adoption permitted). The Company does not expect the adoption of this ASU to have a material impact on its financial statements.

In April 2015, the FASB issued an ASU that is intended to simplify the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This ASU will be applied retrospectively as of the date of adoption and is effective for fiscal years beginning after December 15, 2015, and interim periods within those years (early adoption permitted). The Company does not expect the adoption of this ASU to have a material impact on its financial statements.

In August 2014, the FASB issued an ASU that provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. This ASU is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter (early adoption permitted). The Company does not expect the adoption of this ASU to have a material impact on its financial statements or related disclosures.

In May 2014, the FASB issued an ASU that is intended to improve and converge the financial reporting requirements for revenue from contracts with customers. This ASU will be applied either retrospectively or as a cumulative-effect adjustment as of the date of adoption and is effective for fiscal years beginning after December 15, 2017, and interim periods within those years (early adoption permitted for fiscal years beginning after December 15, 2016, including interim periods within that year). The Company is currently evaluating the impact, if any, of the adoption of this ASU on its financial statements and related disclosures.

Cash Equivalents

For purposes of the statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

Accounts Receivable – Trade, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential recovery is remote. The Company had no allowance for doubtful accounts at December 31, 2015, or December 31, 2014.

Inventories

Materials, supplies and commodity inventories are valued at the lower of average cost or market. Inventories also include California carbon allowance instruments.

Oil and Natural Gas Properties

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold 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 currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of approximately $2 million, $6 million, $41,000 and $6 million for the years ended December 31, 2015, and December 31, 2014, and for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. 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 market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices.

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BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Based on the analysis described above, the Company recorded the following noncash impairment charges (before and after tax) associated with proved oil and natural gas properties:

	Year Ended December 31,	
	2015	2014
	(in thousands)	
California operating area	$537,511	$22
Uinta Basin operating area	111,339	253,340
East Texas operating area	78,437	—
Piceance Basin operating area	55,344	—
	$782,631	$253,362

The impairment charges in 2015 were due to a decline in commodity prices, changes in expected capital development and a decline in the Company's estimates of proved reserves. The impairment charges in 2014 were due to a steep decline in commodity prices during the fourth quarter of 2014. The Company recorded no impairment charges for proved properties for the periods from December 17, 2013 through December 31, 2013, or January 1, 2013 through December 16, 2013.

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 are included in "impairment of long-lived assets" on the statements of operations.

Subsequent to December 31, 2015, the prices of oil, natural gas and NGL have continued to be volatile. In the future, if forward price curves continue to decline, the Company may have additional impairments which could have a material impact on its results of operations.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past.

For the year ended December 31, 2015, the Company recorded noncash impairment charges (before and after tax) of approximately $71 million associated with unproved oil and natural gas properties in California. The Company recorded no impairment charges for unproved properties for the year ended December 31, 2014, or for the periods from December 17, 2013 through December 31, 2013, or January 1, 2013 through December 16, 2013.

The impairment charges in 2015 were primarily due to changes in the Company's future planned capital development in certain operating areas as a result of declines in commodity prices. 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 the statement of operations.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The Company recorded no exploration costs during the years ended December 31, 2015, and December 31, 2014, or for the period from December 17, 2013 through December 31, 2013. The Company recorded noncash leasehold impairment

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expenses related to unproved properties of approximately $16 million for the period from January 1, 2013 through December 16, 2013, which is included in “exploration costs” on the statement 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 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.

Income Taxes and Uncertain Tax Positions

The successor Company is 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 Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company.

Prior to the LINN Energy transaction on December 16, 2013, the Company was a Subchapter C-corporation. For predecessor periods prior to December 17, 2013, income taxes were recorded for the income tax effects of transactions reported in the financial statements and consist of income taxes payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes were also recognized for income tax credits that were available to offset future income taxes. Deferred income taxes were measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. The Company routinely assessed the realizability of its deferred income tax assets, and a valuation allowance was recognized if it was determined that deferred income tax assets may not be fully utilized in future periods. The Company considered future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). The predecessor Company was subject to taxation in many jurisdictions, and the calculation of its income tax liabilities involved dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. The Company recognized certain income tax positions that met a more-likely-than not recognition threshold. If the Company ultimately determined that the payment of these liabilities would be unnecessary, the Company reversed the liability and recognized an income tax benefit during the period in which the Company determined the liability no longer applied.

Derivative Instruments

Historically, the Company has hedged a portion of its forecasted production to reduce exposure to fluctuations in oil and natural gas prices. The Company also, from time to time, has entered into derivative contracts for a portion of its natural gas consumption. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company’s ability to effectively hedge its NGL production. The Company has also hedged its exposure to natural gas differentials in certain operating areas but does not currently hedge exposure to oil differentials. By removing a portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

The Company has historically entered into commodity hedging transactions primarily in the form of swap contracts, collars and three-way collars, and may enter into put option contracts in the future. The Company does not enter into derivative contracts for trading purposes.

A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price. A put option requires the

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BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date.
Derivative instruments are recorded at fair value and included on the balance sheets as assets or liabilities. The Company did not designate any of its contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company determines the fair value of its 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. Company management validates 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. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads are applied to the Company's commodity derivatives. See Note 7 and Note 8 for additional details about the Company's derivative financial instruments.
Fair Value of Financial Instruments
The carrying values of the Company's receivables, payables and Credit Facility (as defined in Note 3) are estimated to be substantially the same as their fair values at December 31, 2015, and December 31, 2014. See Note 3 for fair value disclosures related to the Company's other outstanding debt. As noted above, the Company carries its derivative financial instruments at fair value. See Note 8 for details about the fair value of the Company's derivative financial instruments.
Deferred Financing Fees
The Company incurred legal and bank fees related to the issuance of debt. At December 31, 2015, net deferred financing fees of approximately $8 million are included in "other current assets" on the balance sheet. At December 31, 2014, net deferred financing fees of approximately $12 million are included in "other noncurrent assets" on the balance sheet. These debt issuance costs are amortized over the life of the debt agreement. Upon early retirement or amendment to the debt agreement, certain fees are written off to expense. For the years ended December 31, 2015, and December 31, 2014, and for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, amortization expense of approximately $3 million, $3 million, $83,000 and $5 million, respectively, is included in "interest expense, net of amounts capitalized" on the statements of operations. For the years ended December 31, 2015, and December 31, 2014, approximately $3 million and $256,000, respectively, were written off to expense and included in "other, net" on the statements of operations related to amendments of the Credit Facility.
Other Current Assets
The components of other current assets are as follows:

	December 31,	
	2015	2014
	(in thousands)	
Prepaid expenses	$1,903	$1,210
California carbon allowance inventories	7,073	38,409
Oil inventories	3,446	4,034
Materials inventories	—	1,747
Deferred financing fees	8,108	—
Receivables from exchanges of properties and divestitures, and other	367	13,859
Other current assets	$20,897	$59,259

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Other Accrued Liabilities
The components of other accrued liabilities are as follows:

	December 31, 2015	2014
	(in thousands)	
Accrued interest	$14,096	$15,803
Asset retirement obligations	2,548	3,101
Other	92	183
Other accrued liabilities	$16,736	$19,087

Restricted Cash
At December 31, 2015, "restricted cash" on the balance sheet includes $250 million that LINN Energy borrowed under the LINN credit facility and contributed to Berry in May 2015 to post with Berry's lenders in connection with the reduction in its borrowing base. See Note 3 for additional details.
Business and Credit Concentrations
The Company maintains its cash in bank deposit accounts which at times may exceed federally insured amounts. The Company has not experienced any losses in such accounts. The Company believes it is not exposed to any significant credit risk on its cash.
The Company sells 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, the Company believes that the loss of any one of its major purchasers would not have a material adverse effect on its financial condition, results of operations or net cash provided by operating activities.
For the year ended December 31, 2015, the Company's three largest customers represented approximately 24%, 23% and 20% of the Company's oil, natural gas and NGL sales. For the year ended December 31, 2014, the Company's two largest customers represented approximately 49% and 12% of the Company's oil, natural gas and NGL sales. For the period from December 17, 2013 through December 31, 2013, the Company's two largest customers represented approximately 50% and 10% of the Company's oil, natural gas and NGL sales. For the period from January 1, 2013 through December 16, 2013, the Company's two largest customers represented approximately 45% and 10% of the Company's oil, natural gas and NGL sales. For the years ended December 31, 2015, December 31, 2014, and December 31, 2013, 100% of electricity sales were attributable to two customers.
At December 31, 2015, trade accounts receivable from three customers represented approximately 24%, 22% and 11% of the Company's receivables. At December 31, 2014, trade accounts receivable from two customers represented approximately 36% and 10% of the Company's receivables.
Revenue Recognition
Revenues representative of the Company's ownership interest in its properties are presented on a gross basis on the statements of operations. Sales of oil, natural gas and NGL are recognized when the product has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. The electricity and natural gas the Company produces and uses in its operations are not included in revenues. In addition, the Company engages in the purchase, gathering and transportation of third-party natural gas and subsequently markets such natural gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing revenues and marketing expenses.

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Electricity Cost Allocation
The Company owns three cogeneration facilities. Its investment in cogeneration facilities has been for the express purpose of lowering steam costs in its 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. The Company allocates steam costs to lease operating expenses based on the conversion efficiency of the cogeneration facilities plus certain direct costs of producing steam. A portion of the costs of operating the cogeneration facilities is also allocated to depreciation, depletion and amortization.
Supplemental Disclosures to Statements of Cash Flows
Supplemental disclosures to the statements of cash flows are presented below:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Cash payments for interest, net of amounts capitalized	$86,226	$95,915	$—	$87,495
Cash payments for income taxes	$—	$—	$—	$622
Noncash investing activities:				
Accrued capital expenditures	$10,551	$59,884	$77,001	$70,866

For the year ended December 31, 2015, LINN Energy spent approximately $165 million of capital expenditures in respect of Berry's operations. Berry recorded the $165 million to oil and natural gas properties with an offset to the advance due from LINN Energy. On September 30, 2015, LINN Energy repaid in full the remaining advance of approximately $129 million to Berry.
In addition, in May 2015, LINN Energy made a capital contribution of $250 million to Berry which was deposited on Berry's behalf and posted as restricted cash with Berry's lenders in connection with the reduction in its borrowing base (see Note 3).
On November 21, 2014, and August 15, 2014, the Company, along with a subsidiary of its indirect parent LINN Energy, completed noncash exchanges of a portion of its Permian Basin properties to ExxonMobil and Exxon XTO (each as defined in Note 2) in exchange for properties in California's South Belridge Field and the Hugoton Basin, respectively.
Note 2 – Exchanges of Properties, Divestiture and LINN Energy Transaction
Exchanges of Properties – 2014
On November 21, 2014, the Company, along with a subsidiary of its indirect parent LINN Energy, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation ("ExxonMobil") in exchange for properties in California's South Belridge Field. The noncash exchange was accounted for at fair value and the Company recognized a net loss of approximately $30 million.
On August 15, 2014, the Company, along with a subsidiary of LINN Energy, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc. ("Exxon XTO"), in exchange for properties in the Hugoton Basin. The noncash exchange was accounted for at fair value and the Company recognized a net loss of approximately $34 million.

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In connection with the exchanges, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the exchange dates, while transaction and integration costs associated with the exchanges were expensed as incurred. The losses on the exchanges are equal to the difference between the carrying value and the fair value of the assets exchanged less costs to sell, and are included in "(gains) losses on sale of assets and other, net" on the statement of operations. The fair value measurements were based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

Divestiture – 2014

On November 14, 2014, the Company, along with a subsidiary of LINN Energy, completed the sale of certain of its Wolfberry properties in Ector and Midland counties in the Permian Basin to Fleur de Lis Energy, LLC ("Permian Basin Assets Sale"). Cash proceeds from the sale of these properties were approximately $352 million, net of costs to sell of approximately $2 million, and the Company recognized a net loss of approximately $50 million. The loss is included in "(gains) losses on sale of assets and other, net" on the statement of operations.

The net cash proceeds from the Permian Basin Assets Sale were advanced by the Company to a subsidiary of LINN Energy. These proceeds were required to be used by LINN Energy on capital expenditures in respect of Berry's operations, to repay Berry's indebtedness or as otherwise permitted under the terms of Berry's indentures and Credit Facility. During the twelve months ended September 30, 2015, LINN Energy spent approximately $223 million, including approximately $58 million in 2014, of capital expenditures in respect of Berry's operations. On September 30, 2015, LINN Energy repaid in full the remaining advance of approximately $129 million to Berry. In October 2015, Berry used that cash to repay borrowings under its Credit Facility.

LINN Energy Transaction

On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between LINN Energy, LinnCo, an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and LINN Energy, under which LinnCo contributed Berry to LINN Energy in exchange for LINN Energy units. Under the merger agreement, as amended, Berry's shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units, after which Berry became an indirect wholly owned subsidiary of LINN Energy. The transaction was valued at approximately $4.6 billion, including the assumption of approximately $2.3 billion of Berry's debt and net of cash acquired of approximately $451 million.

On the Berry acquisition date, LinnCo contributed Berry to its affiliate, LINN Energy. As a result, the assets, liabilities and results of operations of Berry are not included in LinnCo's financial statements.

The acquisition was accounted for under the acquisition method of accounting. Accordingly, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition date, while transaction and integration costs associated with the acquisition were expensed as incurred. In connection with the LINN Energy transaction, the Company incurred transaction costs of approximately $16 million and $45 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

On December 16, 2013, the Company was formed as a limited liability company and ceased to be subject to federal and state income taxes, with the exception of the state of Texas. The Company's net deferred income tax liabilities were assumed by LinnCo in the merger and were not transferred to LINN Energy in the contribution.

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Note 3 – Debt
The following summarizes the Company's outstanding debt:

	December 31, 2015	December 31, 2014
	(in thousands, except percentages)	
Credit facility [1]	$873,175	$1,173,175
6.75% senior notes due November 2020	261,100	299,970
6.375% senior notes due September 2022	572,700	599,163
Net unamortized premiums	11,568	14,644
Total debt, net	1,718,543	2,086,952
Less current portion [2]	(873,175)	—
Total long-term debt, net	$845,368	$2,086,952

(1) Variable interest rates of 3.17% and 2.67% at December 31, 2015, and December 31, 2014, respectively.
(2) Due to existing and anticipated covenant violations, the Company's credit facility was classified as current at December 31, 2015.

Fair Value
The Company's debt is recorded at the carrying amount in the balance sheets. The carrying amount of the Company's Credit Facility, as defined below, approximates fair value because the interest rate is variable and reflective of market rates. The Company uses a market approach to determine the fair value of its senior notes using estimates based on prices quoted from third-party financial institutions, which is a Level 2 fair value measurement.

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Credit facility	$873,175	$873,175	$1,173,175	$1,173,175
Senior notes, net	845,368	200,249	913,777	699,462
Total debt, net	$1,718,543	$1,073,424	$2,086,952	$1,872,637

Credit Facility
The Company's Second Amended and Restated Credit Agreement ("Credit Facility") had a borrowing base of $900 million, subject to lender commitments, as of December 31, 2015. The maturity date is April 2019. At December 31, 2015, lender commitments under the facility were also $900 million but there was less than $1 million of available borrowing capacity, including outstanding letters of credit.
In October 2015, the Company entered into an amendment to the Credit Facility to provide for, among other things: (i) a springing maturity based on the maturity of any outstanding junior lien debt; (ii) the ability of the Company to incur junior lien debt to refinance its senior notes or as additional indebtedness, but such additional indebtedness issued may not exceed $500 million outstanding at any one time and is subject to a borrowing base reduction; (iii) a decrease in the Company's covenant requiring the maintenance of an EBITDA to Interest Expense ratio of 2.5 to 1.0, such that the permissible ratio is decreased to 2.0 to 1.0 from December 31, 2015 through December 31, 2016, to 2.25 to 1.0 from March 31, 2017 through June 30, 2017 and returning to 2.5 to 1.0 thereafter; (iv) an increase in the mortgage requirement on the total value of the oil and natural gas properties included in the Company's most recent reserve report from 80% to 90%; (v) an increase to the applicable margin charged on borrowings under the Credit Facility by 0.25% and increase the commitment fee under the

Credit Facility to 0.5% per annum; and (vi) permission to prepay or exchange the Company's senior notes with notes issued by LINN Energy.

Redetermination of the borrowing base under the Credit Facility, based primarily on reserve reports using lender commodity price expectations at such time, occurs semi-annually, in April and October. A super-majority of the lenders under the Credit Facility and Berry also have the right to request interim borrowing base redeterminations once between scheduled redeterminations. The spring 2015 semi-annual borrowing base redetermination was completed in May 2015, and as a result of lower commodity prices, the borrowing base under the Credit Facility decreased from $1.4 billion to $1.2 billion. The fall 2015 semi-annual redetermination was completed in October 2015 and the borrowing base under the Credit Facility decreased from $1.2 billion to $900 million. In connection with the reduction in Berry's borrowing base in October 2015, Berry repaid $300 million of borrowings outstanding under the Credit Facility. Continued low commodity prices, reductions in the Company's capital budget and the resulting reserve write-downs are expected to adversely impact future redeterminations.

In connection with the reduction in Berry's borrowing base in May 2015, LINN Energy contributed $250 million to Berry to post as restricted cash with Berry's lenders. As directed by LINN Energy, the $250 million was deposited on Berry's behalf in a security account with the administrative agent subject to a security control agreement. Berry's ability to withdraw funds from this account is subject to a concurrent reduction of the borrowing base under the Credit Facility or lender's consent in connection with a redetermination of such borrowing base. The $250 million may be used to satisfy obligations under the Credit Facility or, subject to restrictions in the indentures governing Berry's senior notes, may be returned to LINN Energy in the future. The amount is included in "restricted cash" on the balance sheet.

The Company's obligations under the Credit Facility, as amended, are secured by mortgages on its oil and natural gas properties and other personal property. The Company is required to maintain mortgages on properties representing at least 90% of the present value of its oil and natural gas proved reserves.

At the Company's election, interest on borrowings under the Credit Facility, as amended, is determined by reference to either the LIBOR plus an applicable margin between 1.75% and 2.75% per annum (depending on the then-current level of borrowings under the Credit Facility) or a Base Rate (as defined in the Credit Facility) plus an applicable margin between 0.75% and 1.75% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the Base Rate and at the end of the applicable interest period for loans bearing interest at the LIBOR. The Company is required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum of 0.5% on the average daily unused amount of the maximum commitment amount of the lenders.

Senior Notes Due November 2020

The Company has approximately $261 million in aggregate principal amount of 6.75% senior notes due November 2020 ("November 2020 Senior Notes"). The November 2020 Senior Notes were recorded at their fair value of $310 million on the acquisition date including a $10 million premium which is being amortized to interest expense over the life of the related notes.

The Company may redeem all or any part of the November 2020 Senior Notes at any time at the redemption prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.375	%
2016	102.250	%
2017	101.125	%
2018 and thereafter	100.000	%

The Company may also redeem the November 2020 Senior Notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium, plus accrued and unpaid interest to the redemption date.

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Senior Notes Due September 2022
The Company has approximately $573 million in aggregate principal amount of 6.375% senior notes due September 2022 (“September 2022 Senior Notes”). The September 2022 Senior Notes were recorded at their fair value of $607 million on the acquisition date including a $7 million premium which is being amortized to interest expense over the life of the related notes.
At any time prior to March 15, 2017, the Company may redeem all or part of the September 2022 Senior Notes at a redemption price equal to 100% of the principal amount of the notes redeemed plus a “make-whole” premium described in the indenture, plus accrued and unpaid interest, if any, to the redemption date.
On and after March 15, 2017, the Company may redeem all or, from time to time, a part of the September 2022 Senior Notes upon not less than 30 nor more than 60 days’ notice, at the following redemption prices (expressed as a percentage of principal amount of notes to be redeemed), plus accrued and unpaid interest, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the 12-month period beginning on March 15 of the years indicated below:

2017	103.188	%
2018	102.125	%
2019	101.063	%
2020 and thereafter	100.000	%

The November 2020 Senior Notes and September 2022 Senior Notes are senior unsecured obligations of the Company, which rank effectively junior in right of payment to all of the Company’s existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with any of the Company’s future senior unsecured debt and rank senior in right of payment to any of the Company’s future subordinated debt.
Redemption and Repurchases of Senior Notes
During the year ended December 31, 2015, the Company repurchased, on the open market and through a privately negotiated transaction, approximately $65 million of its outstanding senior notes including approximately $39 million of its 6.75% senior notes due November 2020 and approximately $26 million of its 6.375% senior notes due September 2022. In connection with the repurchases, the Company paid approximately $55 million in cash and recorded a gain on extinguishment of debt of approximately $11 million for the year ended December 31, 2015.
On May 30, 2014, in accordance with the provisions of the indenture related to its 10.25% senior notes due June 2014 (“June 2014 Senior Notes”), the Company paid in full the remaining outstanding principal amount of approximately $205 million using a cash capital contribution from LINN Energy (see Note 12).
In February 2014, in accordance with the indentures related to the senior notes, the Company repurchased through cash tender offers $321,000, $30,000 and $837,000 of its June 2014 Senior Notes, November 2020 Senior Notes and September 2022 Senior Notes, respectively.
Senior Notes Covenants
The Company’s senior notes contain covenants that, among other things, may limit its ability to: (i) incur or guarantee additional indebtedness; (ii) pay distributions or dividends on its equity or redeem its subordinated debt; (iii) create certain liens; (iv) enter into agreements that restrict distributions or other payments from the Company’s restricted subsidiaries to the Company; (v) sell assets; (vi) engage in transactions with affiliates; and (vii) consolidate, merge or transfer all or substantially all of the Company’s assets. As of December 31, 2015, the Company was in compliance with all financial and other covenants of its senior notes.
In addition, any cash generated by the Company is currently being used by the Company to fund its activities. To the extent that the Company generates cash in excess of its needs and determines to distribute such amounts to LINN Energy, the

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indentures governing the Company's senior notes limit the amount it may distribute to LINN Energy to the amount available under a "restricted payments basket," and the Company may not distribute any such amounts unless it is permitted by the indentures to incur additional debt pursuant to the consolidated coverage ratio test set forth in the Company's indentures. The Company's restricted payments basket may be increased in accordance with the terms of the Company's indentures by, among other things, 50% of the Company's future net income, reductions in its indebtedness and restricted investments, and future capital contributions.

The Company may from time to time seek to repurchase its outstanding debt through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, may be material and will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors.

Covenant Violations

The audit report the Company received with respect to its financial statements contains an explanatory paragraph expressing uncertainty as to the Company's ability to continue as a going concern, the delivery of which constitutes a default under the Credit Facility. The Company also deferred making an interest payment totaling approximately $18 million due March 15, 2016, on the Company's senior notes due September 2022, which resulted in the Company being in default under these senior notes. See "Going Concern Uncertainty" in Note 1 for additional information.

Note 4 – Income Taxes

The Company is 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 Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company, except as set forth in the tables below. Prior to the LINN Energy transaction in December 2013, the Company was a Subchapter C-corporation subject to federal and state income taxes. Amounts recognized for income taxes are reported in "income tax expense (benefit)" on the statements of operations.

Income tax expense (benefit) consisted of the following:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Current taxes:				
Federal	$—	$—	$—	$(225)
State	—	—	—	(11,043)
Deferred taxes:				
Federal	—	—	—	56,620
State	(68)	69	—	19,928
	$(68)	$69	$—	$65,280

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A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
Federal statutory rate	35 %	35 %	35 %	35 %
State, net of federal tax benefit	—	—	—	3
Income excluded from nontaxable entities	(35)	(35)	(35)	—
Net impact to uncertain income tax positions	—	—	—	(2)
Transaction costs	—	—	—	4
Other	—	—	—	1
Effective rate	— %	— %	— %	41 %

The effective tax rate was zero for the years ended December 31, 2015, and December 31, 2014, and for the period from December 17, 2013 through December 31, 2013, as the Company is a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas.

Significant components of the deferred tax assets and liabilities are as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$—	$—
Other	—	—
	—	—
Deferred tax liabilities:		
Property and equipment principally due to differences in depreciation	—	—
Other	1	69
	1	69
Net deferred tax liabilities	$1	$69

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. At December 31, 2015, the Company is in a net deferred tax liability position and has no deferred tax assets.

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Changes in the balance of unrecognized tax benefits, excluding interest and penalties on uncertain tax positions, were as follows:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Unrecognized tax benefits at beginning of period	$—	$—	$—	$22,553
Increases for positions taken in current year	—	—	—	50
Decreases for positions taken in a prior year	—	—	—	(635)
Decreases for settlements with taxing authorities	—	—	—	—
Decreases for lapses in the applicable statute of limitations	—	—	—	(1,862)
Unrecognized tax benefits at end of period	$—	$—	$—	$20,106

In accordance with the applicable accounting standards, the Company recognizes only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. To evaluate its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy of identifying and evaluating uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. It is the Company's policy to recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. The Company had no material uncertain tax positions at December 31, 2015, or December 31, 2014.

On December 16, 2013, the date of the LINN Energy transaction, all unrecognized tax benefits of the predecessor were assumed by LinnCo. The tax years 2013 – 2015 remain open to examination for income tax purposes in the state of Texas.

During the predecessor period from January 1, 2013 through December 16, 2013, the Company decreased the unrecognized tax benefits by approximately $2 million due to the closing of certain federal and state income tax years, which resulted in a reduction of the effective income tax rate. As of December 16, 2013, the Company had a gross liability for uncertain income tax benefits of approximately $20 million.

Note 5 – Member's and Shareholders' Equity

On December 16, 2013, in connection with the LINN Energy transaction, the outstanding Class A Common Stock ("Common Stock") and Class B Stock of the Company were acquired by LinnCo, an affiliate of LINN Energy. On that date, the Company was reorganized as a Delaware limited liability company and its sole member is Linn Acquisition Company, LLC, a direct subsidiary of LINN Energy.

Prior to being acquired by LinnCo, shares of Common Stock and Class B Stock were entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock was entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock was convertible into one share of Common Stock at the option of the holder.

Dividends

The regular annual dividend for 2013 was $0.32 per share and was paid quarterly in March, June, September and December. Dividend payments were limited at such time by covenants in the Credit Facility to the greater of $35 million or 75% of net income for any four quarter period. In addition, the indentures governing the Company's senior notes contain provisions potentially restricting the Company's ability to declare dividends if certain situations arose; provided that, notwithstanding such restrictions, the Company may declare dividends up to $0.36 per share annually (so long as such distributions did not exceed $20 million annually) in the event that the Company was not in default under the indentures and up to $10 million in the event that the Company was in a nonpayment default under the indentures. Since December 16, 2013, the effective date of the LINN Energy transaction, the Company has not declared a dividend and does not currently plan to do so in the future. However, the Company has the ability to make distributions to LINN Energy in accordance with the terms of the indentures governing its senior notes.

Note 6 – Equity Incentive Compensation Plans and Other Benefit Plans

The successor Company does not have any equity incentive plans under which it grants stock awards. Prior to the LINN Energy transaction, the Company granted equity awards to its employees under its own equity incentive plans. The predecessor Company recognized stock-based compensation expense over the requisite service period in an amount equal to the fair value of stock-based awards granted to employees and nonemployee directors. The fair value of stock-based awards was computed at the date of grant and was not remeasured.

In connection with the LINN Energy transaction, effective December 16, 2013, the following occurred with respect to the Company's stock-based incentive awards:

Each Company restricted stock unit ("RSU") that was vested as of the effective time of the acquisition, that was held by a current or former nonemployee director or by an employee of the Company whose employment was terminated in connection with the acquisition as agreed by the parties or that was subject to performance-based vesting criteria was converted as of the effective time of the acquisition into a number of LinnCo common shares equal to the product determined by multiplying the number of shares of the Company's Common Stock subject to the Company RSU immediately prior to the effective time of the acquisition by the exchange ratio (1.68). Each performance-based Company RSU that was outstanding immediately prior to the effective time of the acquisition was deemed to have been earned at the target level as specified in the applicable award agreement.

Each unvested Company RSU (excluding any Company RSU held by a current or former nonemployee director of the Company or by an employee of the Company whose employment was terminated in connection with the acquisition as agreed by the parties and any performance-based Company RSU) was converted into a restricted unit award in respect of the number of LINN Energy units (rounded to the nearest whole unit) equal to the product determined by multiplying the number of shares of the Company Common Stock subject to the Company RSU immediately prior to the effective time of the acquisition by the exchange ratio (1.68) and by the LinnCo/LINN exchange ratio (1.0013), and are subject generally to the same terms and conditions as were applicable to the related Company RSU immediately prior to the effective time of the acquisition. The LinnCo/LINN exchange ratio was the average of the closing prices of one LinnCo common share on the NASDAQ on the last five full trading days prior to the closing date of the acquisition divided by the average of the closing prices of one LINN Energy unit on the NASDAQ on the last five full trading days prior to the closing date of the acquisition.

Each option to purchase shares of the Company Common Stock was converted into an option to purchase, generally on the same terms and conditions as were applicable to such option immediately prior to the effective time of the acquisition, (i) a number of LINN Energy units (rounded down to the nearest whole unit) equal to the product determined by multiplying the number of shares of Company Common Stock subject to such option by the exchange ratio and by the LinnCo/LINN exchange ratio, (ii) at an exercise price per LINN Energy unit (rounded up to the nearest whole cent) equal to the quotient determined by dividing the per share exercise price for the shares of Company Common Stock subject to the option by the product determined by multiplying the exchange ratio and the LinnCo/LINN exchange ratio.

The following disclosures relate to the predecessor periods and the conversion of Company RSUs and options only. All information is based on historical Company stock prices and includes no adjustments for the exchange ratios.

Predecessor Stock Compensation Plans

The Predecessor's 2010 Equity Incentive Plan ("2010 Plan") and 2005 Equity Incentive Plan ("2005 Plan"), collectively, ("Equity Incentive Plans"), approved by the Company's shareholders in May 2010 and May 2005, provided for granting of equity compensation up to an aggregate of 1,000,000 shares and 2,900,000 shares of Common Stock, respectively. The purpose of the Equity Incentive Plans was to encourage ownership in the Company by key personnel whose long-term service was considered essential to the Company's continued progress and, thereby, align participants' and shareholders'

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interests. Stock options, stock appreciation rights ("SAR"), cash awards and stock awards, including restricted shares and stock units, could be granted under the Equity Incentive Plans. The exercise price of an option could not be less than the fair market value of one share of Common Stock on the date of grant. Stock options and RSUs granted under the Equity Incentive Plans historically vested either in increments of 25% on each of the first four anniversary dates of the date of grant or 100% after three years. Stock options and RSUs granted to nonemployee directors historically vested immediately. Options granted under the Equity Incentive Plans had a term of ten years.

The total compensation expense recognized by the predecessor in the statement of operations for grants under the Equity Incentive Plans was approximately $12 million for the period from January 1, 2013 through December 16, 2013.

Stock Options

The following table presents stock option activity under the predecessor's Equity Incentive Plans for the period from January 1, 2013 through December 16, 2013:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands) (1)	Weighted Average Remaining Contractual Term (Years)
Outstanding at December 31, 2012	1,387,592	$33.71	$4,681	
Exercised	(57,350)	$12.74	$2,066	
Outstanding at December 16, 2013	1,330,242	$34.61	$19,243	3.21
Vested and expected to vest at December 16, 2013	1,328,771	$34.60	$19,243	3.21
Exercisable at December 16, 2013	1,224,022	$33.18	$19,229	2.81

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the end of the related period exceeds the exercise price of the option.

The following table presents information about stock options at December 16, 2013:

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Term (Years)	Weighted Average Exercise Price	Number of Options	Weighted Average Remaining Contractual Term (Years)	Weighted Average Exercise Price
$21.58-$21.77	240,000	0.90	$21.60	240,000	0.90	$21.60
$30.65-$32.57	639,000	2.50	$31.70	639,000	2.50	$31.70
$38.00-$53.02	451,242	5.43	$45.66	345,022	4.71	$43.98
	1,330,242	3.21	$34.61	1,224,022	2.81	$33.18

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BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Restricted Stock Units
The following table presents RSU activity under the predecessor's Equity Incentive Plans for the period from January 1, 2013 through December 16, 2013:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Vest Date Fair Value (in thousands)
December 31, 2012	981,877	$26.72	
Granted	286,344	$45.51	
Issued	(853,169)	$23.94	$39,513
Canceled/expired	(22,511)	$44.69	
Outstanding at December 16, 2013	392,541	$46.86	

The grant date fair value of RSUs issued under the 2005 Plan and 2010 Plan was based on the average high and low stock price of a share of Common Stock on the date of grant and the closing price of a share of Common Stock on the date of grant, respectively. The Company used historical data and projections to estimate expected restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation expense.
Performance Share Program
The following table presents performance share award activity under the predecessor's Equity Incentive Plans for the period from January 1, 2013 through December 16, 2013:

	Performance Share Awards	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at December 31, 2012	222,587	$45.79	
Issued	(135,167)	$44.33	$6,308
Canceled/expired	(87,420)	$44.42	
Outstanding at December 16, 2013	—	$—	

The vesting of the performance share awards was contingent upon satisfying certain performance criteria. For the portion of the performance share awards subject to internal performance metrics, the grant date fair value was determined by reference to the closing price of a share of Common Stock on the date of grant. The Company recognized compensation expense when it became probable that these conditions would be achieved. However, any such compensation expense recognized was reversed if vesting did not actually occur.
Director Fees
Under the predecessor, the Company's directors could elect to receive their annual retainer and meeting fees in the form of the Company's Common Stock issued pursuant to the Company's Non-Employee Director Deferred Stock and Compensation Plan ("Deferred Plan"). The Deferred Plan permitted eligible directors, in recognition of their contributions to the Company, to receive compensation for service and to defer recognition of their compensation in whole or in part to a stock unit account or an interest account. When the eligible director ceased to be a director, the distribution from the stock unit account was made in shares of Common Stock while the distribution from the interest account was made in cash. Shares of Common Stock earned and deferred in accordance with the Deferred Plan were 10,758 for the period from January 1, 2013 through December 16, 2013.

Amounts allocated to the stock unit account had the right to receive a “dividend equivalent” equal to the dividends declared and paid by the Company and reinvested in additional stock units and credited to the director’s account using an established market value. Amounts allocated to the interest account were credited with interest at an established interest rate.

Defined Contribution Plan

Prior to the LINN Energy transaction, the Company sponsored a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all employees in providing for retirement or other future financial needs. Employees were eligible to participate in the 401(k) Plan on their date of hire and the Company matched 100% of each employee’s contribution up to 8% of an employee’s eligible compensation. Approximately 93% of the Company’s employees participated in the 401(k) Plan and the Company’s contributions to the 401(k) Plan, net of forfeitures, were approximately $2 million for the period from January 1, 2013 through December 16, 2013.

At December 31, 2015, and December 31, 2014, the Company had no employees. All former employees of the Company that were retained after the LINN Energy transaction became employees of Linn Operating, Inc. (“LOI”), a subsidiary of LINN Energy, and along with other LOI personnel, provide services and support to the Company in accordance with an agency agreement and power of attorney between the Company and LOI.

Note 7 – Derivative Instruments

Historically, the Company has hedged a portion of its forecasted production to reduce exposure to fluctuations in oil and natural gas prices. The Company also, from time to time, has entered into derivative contracts for a portion of its natural gas consumption. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company’s ability to effectively hedge its NGL production. The Company has also hedged its exposure to natural gas differentials in certain operating areas but does not currently hedge exposure to oil differentials.

The Company has historically entered into commodity hedging transactions primarily in the form of swap contracts, collars and three-way collars. Swap contracts are designed to provide a fixed price. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price.

The Company enters into these transactions with respect to a portion of its projected production or consumption to provide an economic hedge of the risk related to the future commodity prices received or paid. The Company does not enter into derivative contracts for trading purposes. The Company did not designate any of its contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 8 for fair value disclosures about oil and natural gas commodity derivatives.

The following table presents derivative positions for the period indicated as of December 31, 2015:

	2016
Natural gas basis differential positions: (1)	
NWPL Rockies basis swaps: (2)	
Hedged volume (MMMBtu)	11,712
Hedged differential ($/MMBtu)	$(0.34)
SoCal basis swaps: (3)	
Hedged volume (MMMBtu)	32,940
Hedged differential ($/MMBtu)	$(0.03)

(1) Settle on the respective pricing index to hedge basis differential to the NYMEX Henry Hub natural gas price.

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BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

(2) For positions which hedge exposure to differentials in producing areas, the Company receives the NYMEX Henry Hub natural gas price plus the respective spread and pays the specified index price. Cash settlements are made on a net basis.

(3) For positions which hedge exposure to differentials in consuming areas, the Company pays the NYMEX Henry Hub natural gas price plus the respective spread and receives the specified index price. Cash settlements are made on a net basis.

During the year ended December 31, 2015, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for May 2015 through December 2016 to hedge exposure to differentials in certain producing areas and oil swaps for April 2015 through December 2015. In addition, the Company entered into natural gas basis swaps for May 2015 through December 2016 to hedge exposure to the differential in California, where it consumes natural gas in its heavy oil development operations.

During the fourth quarter of 2014, the Company canceled all of its ICE Brent – NYMEX WTI basis swaps for 2015 and received cash settlements of approximately $12 million.

The Company did not enter into any commodity derivative contracts during the period from December 17, 2013 through December 31, 2013. During the period from January 1, 2013 through December 16, 2013, the Company entered into commodity derivative contracts consisting of oil three-way collars for 2013 through 2014, oil trade month roll swaps, oil collars and oil swaps for 2014 and oil basis swaps for 2013 through 2015.

Settled derivatives on oil production for the year ended December 31, 2015, included volumes of 3,859 MBbls at an average contract price of $67.66 per Bbl. Settled derivatives on oil production for the year ended December 31, 2014, included volumes of 9,125 MBbls at an average contract price of $92.16 per Bbl. The oil derivatives are settled based on the average closing price of NYMEX WTI crude oil for each day of the delivery month.

Balance Sheet Presentation

The Company’s commodity derivatives are presented on a net basis in “derivative instruments” on the balance sheets. The following table summarizes the fair value of derivatives outstanding on a gross basis:

	December 31,	
	2015	2014
	(in thousands)	
Assets:		
Commodity derivatives	$13,807	$60,843
Liabilities:		
Commodity derivatives	$2,830	$17,149

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company’s counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company’s oil, natural gas and NGL reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $14 million at December 31, 2015. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company’s minimum credit quality standard, or have a guarantee from an affiliate that meets the Company’s minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company’s counterparties on an ongoing basis. In accordance with the Company’s standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

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BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Gains (Losses) on Derivatives
A summary of gains and losses on the derivatives included on the statements of operations is presented below:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Gains (losses) on oil and natural gas derivatives	$29,175	$78,784	$(5,049)	$(34,711)
Lease operating expenses [1]	6,893	—	—	—
Total gains (losses) on oil and natural gas derivatives	$36,068	$78,784	$(5,049)	$(34,711)

(1) Consists of gains and (losses) on derivatives used to hedge exposure to differentials in consuming areas, which were entered into in March 2015.

Note 8 – Fair Value Measurements on a Recurring Basis
The Company accounts for its commodity derivatives at fair value (see Note 7) on a recurring basis. The Company determines the fair value of its 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. Company management validates 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. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads are applied to the Company's commodity derivatives.
Fair Value Hierarchy
In accordance with applicable accounting standards, the Company has categorized its financial instruments, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).
Financial assets and liabilities recorded in the balance sheets are categorized based on the inputs to the valuation techniques as follows:

Level 1	Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access.
Level 2	Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability (commodity derivatives).
Level 3	Financial assets and liabilities for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

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NOTES TO FINANCIAL STATEMENTS - Continued

The following presents the fair value hierarchy for assets and liabilities measured at fair value on a recurring basis:

	December 31, 2015		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$13,807	$(589)	$13,218
Liabilities:			
Commodity derivatives	$2,830	$(589)	$2,241

	December 31, 2014		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$60,843	$(17,149)	$43,694
Liabilities:			
Commodity derivatives	$17,149	$(17,149)	$—

[1] Represents counterparty netting under agreements governing such derivatives.

Note 9 – Other Property and Equipment

Other property and equipment consists of the following:

	December 31,	
	2015	2014
	(in thousands)	
Natural gas plant and pipeline	$96,771	$101,626
Buildings and leasehold improvements	5,884	6,559
Vehicles	4,647	3,759
Drilling and other equipment	113	28
Furniture and office equipment	3,879	3,826
Land	201	201
	111,495	115,999
Less accumulated depreciation	(12,522)	(8,452)
	$98,973	$107,547

Note 10 – Asset Retirement Obligations

The Company has the obligation to plug and abandon oil and natural gas wells and related equipment at the end of production operations. Estimated asset retirement costs are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets when the obligation is incurred. The liabilities are included in “other accrued liabilities” and “other noncurrent liabilities” on the balance sheets. Accretion expense is included in “depreciation, depletion and amortization” on the statements of operations. The fair value of additions to the asset retirement obligations is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon 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. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are the most sensitive and subject to change.

The following table presents a reconciliation of the Company’s asset retirement obligations:

	December 31, 2015	2014
	(in thousands)	
Asset retirement obligations at beginning of year	$121,760	$94,830
Liabilities added from drilling	1,270	5,124
Settlements	(683)	(5,260)
Liabilities added from acquisitions	—	25,223
Liabilities associated with assets divested	—	(5,460)
Current year accretion expense	6,897	5,670
Revision of estimates	8,319	1,633
Asset retirement obligations at end of year	$137,563	$121,760

Note 11 – Commitments and Contingencies

Operating Leases and Other Commitments

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2020. The Company recognized expense under operating leases of approximately $6 million for each of the years ending December 31, 2015, and December 31, 2014, and $302,000 and $5 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

The following table presents the Company’s future minimum payments under noncancelable operating leases and other commitments as of December 31, 2015:

	Total	2016	2017	2018	2019	2020	Thereafter
(in thousands)							
Operating leases (1)	$9,377	$3,710	$2,234	$1,279	$1,175	$979	$—
Firm natural gas transportation contracts (2)	146,981	33,446	33,417	23,972	22,528	19,123	14,495
Other commitments (3)	2,442	2,442	—	—	—	—	—
Total	$158,800	$39,598	$35,651	$25,251	$23,703	$20,102	$14,495

(1) Operating leases relate primarily to obligations associated with the Company’s office facilities, rail cars and vehicles.

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

(3) Other commitments relate primarily to cogeneration facility management services and equipment rental obligations.

East Texas Gathering System

The Company is party to certain long-term natural gas gathering agreements for its East Texas production. The agreements contain embedded leases and the transaction was accounted for as a financing obligation. The asset is being depreciated over the remaining useful life and has a net book value of approximately $5 million at December 31, 2015. There are no minimum payments required under these agreements.

Carry and Earning Agreement

In January 2011, the Company entered into an amendment relating to certain contractual obligations to a third-party co-owner of certain Piceance Basin assets in Colorado. The amendment waives a $200,000 penalty for each well not spud by February 2011 and requires the Company to reassign to such third party, by January 31, 2020, all of the interest acquired by the

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NOTES TO FINANCIAL STATEMENTS - Continued

Company from the third party in each 160-acre tract in which the Company has not drilled and completed a well that is producing or capable of producing from a designated formation, or deeper formation, on January 1, 2020. The amendment also requires the Company to pay the first $9 million of costs incurred in connection with the construction of either an extension of the existing access road or a new access road, including the third party's 50% share. Pursuant to the terms of a further amendment effective September 30, 2015, if by September 30, 2017, the Company does not expend $9 million on the construction of either the extension of the existing access road or a new access road, the Company is obligated to pay the third party 50% of the difference between $12 million and the actual amount expended on road construction as of such date. Under the terms of the 2015 amendment, this deadline is subject to further extension to no later than December 31, 2017. Due to the need to obtain regulatory approvals, among other reasons, the Company has not yet commenced construction of either an extension of the existing access road or a new access road and may be unable to do so by the extended deadline, thus triggering the payment of the obligation to the third party.

Environmental Matters

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in material costs to the Company.

Legal Matters

The Company is involved in various lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

During the years ended December 31, 2015, and December 31, 2014, and the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Note 12 – Related Party Transactions

LINN Energy

On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between LINN Energy, LinnCo, an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and LINN Energy, under which LinnCo contributed Berry to LINN Energy in exchange for LINN Energy units. Under the merger agreement, as amended, Berry's shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units, after which Berry became an indirect wholly owned subsidiary of LINN Energy. Berry's sole member is Linn Acquisition Company, LLC, a direct subsidiary of LINN Energy. See Note 2 for more information.

All former employees of the Company that were retained after the LINN Energy transaction became employees of LOI, a subsidiary of LINN Energy, and along with other LOI personnel, provide services and support to the Company in accordance with an agency agreement and power of attorney between the Company and LOI. For the years ended December 31, 2015, and December 31, 2014, and for the period from December 17, 2013 through December 31, 2013, the Company incurred management fee expenses of approximately $78 million, $86 million and $20 million, respectively, for services provided by LOI. The Company also had affiliated accounts payable due to LINN Energy of approximately $9 million and $13 million at

December 31, 2015, and December 31, 2014, respectively, included in “accounts payable and accrued expenses” on the balance sheets.

During the year ended December 31, 2015, Linn Energy made capital contributions of approximately $471 million to Berry, including $250 million that was deposited on Berry’s behalf and posted as restricted cash with Berry’s lenders in connection with the reduction in its borrowing base in May 2015 (see Note 3). The $250 million may be used to satisfy obligations under the Credit Facility or may be returned to LINN Energy in the future if commodity prices improve. During the second quarter of 2014, LINN Energy made a cash capital contribution of $220 million to the Company which was used to pay in full the remaining outstanding principal amount of its approximate $205 million 10.25% senior notes due June 2014 plus accrued interest.

During the year ended December 31, 2015, the Company made cash distributions of approximately $89 million to LINN Energy. During the year ended December 31, 2014, the Company made cash distributions of approximately $119 million to LINN Energy. In addition, in 2014, the Company advanced approximately $352 million, to a subsidiary of LINN Energy, of net cash proceeds from the Permian Basin Assets Sale. These proceeds were required to be used by LINN Energy on capital expenditures in respect of Berry’s operations, to repay Berry’s indebtedness or as otherwise permitted under the terms of Berry’s indentures and Credit Facility. During the twelve months ended September 30, 2015, LINN Energy spent approximately $223 million, including approximately $58 million in 2014, of capital expenditures in respect of Berry’s operations. On September 30, 2015, LINN Energy repaid in full the remaining advance of approximately $129 million to Berry. In October 2015, Berry used that cash to repay borrowings under its Credit Facility.

On December 19, 2013, the Company made a cash distribution of $435 million to LINN Energy. Also in 2013, in connection with the LINN Energy transaction, LINN Energy transferred a derivative liability of approximately $31 million to the Company.

Other

One of LINN Energy’s directors is the President and Chief Executive Officer of Superior Energy Services, Inc. (“Superior”), which provides oilfield services to the Company. For the years ended December 31, 2015, and December 31, 2014, the Company incurred expenditures of approximately $562,000 and $176,000, respectively, related to services rendered by Superior and its subsidiaries.

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BERRY PETROLEUM COMPANY, LLC
SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the "Financial Statements" and "Notes to Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data."

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:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Property acquisition costs:				
Proved	$—	$478,311	$—	$3,457
Unproved	—	—	—	463
Exploration costs	—	148	—	868
Development costs	130,276	555,629	22,266	577,568
Asset retirement costs	2,151	6,064	—	15,998
Total costs incurred [(1)]	$132,427	$1,040,152	$22,266	$598,354

(1) The total above does not reflect approximately $2 million, $6 million, $41,000 and $6 million of capitalized interest incurred for the years ended December 31, 2015, and December 31, 2014, and for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively.

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:

	December 31, 2015	2014
	(in thousands)	
Oil and natural gas:		
Proved properties	$4,231,836	$4,025,595
Unproved properties	779,225	846,464
	5,011,061	4,872,059
Less accumulated depletion and amortization	(1,596,165)	(525,007)
	$3,414,896	$4,347,052

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BERRY PETROLEUM COMPANY
SUPPLEMENTAL OIL & NATURAL GAS DATA (Unaudited) - Continued

Results of Oil and Natural Gas Producing Activities
The results of operations for oil, natural gas and NGL producing activities (excluding corporate overhead and interest costs) are presented below:

	Successor			Predecessor
	Year Ended December 31, 2015	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)				
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$575,031	$1,298,402	$50,324	$1,103,245
Gains (losses) on oil and natural gas derivatives	29,175	78,784	(5,049)	(34,711)
	604,206	1,377,186	45,275	1,068,534
Production costs:				
Lease operating expenses	245,155	364,540	15,410	295,811
Transportation expenses	52,160	41,842	2,576	46,774
Severance taxes, ad valorem taxes and California carbon allowances	70,591	97,683	2,130	57,063
	367,906	504,065	20,116	399,648
Other costs:				
Exploration costs	—	—	—	24,048
Depletion and amortization	241,019	294,107	10,612	275,927
Impairment of long-lived assets	853,810	253,362	—	—
(Gains) losses on sale of assets and other, net	372	112,303	10,208	(23)
	1,095,201	659,772	20,820	299,952
Income tax expense (benefit)	(68)	69	—	65,280
Results of operations	$(858,833)	$213,280	$4,339	$303,654

There is no federal tax provision included in the results above for the years ended December 31, 2015, and December 31, 2014, or for the period from December 17, 2013 through December 31, 2013, because the Company was not subject to federal income taxes during those periods. The income tax amount included in the results above for the years ended December 31, 2015 and December 31, 2014, relates to Texas margin tax expense. Limited liability companies are subject to Texas margin tax. See Note 4 for additional information about income taxes.

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BERRY PETROLEUM COMPANY

SUPPLEMENTAL OIL & NATURAL GAS DATA (Unaudited) - Continued

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, 2015, December 31, 2014, and December 31, 2013, 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:

	Successor Year Ended December 31, 2015				Year Ended December 31, 2014			
	Oil MBbls	NGL MBbls	Natural Gas MMcf	Total MBOE	Oil MBbls	NGL MBbls	Natural Gas MMcf	Total MBOE
Total proved reserves:								
Beginning of year	144,410	19,992	687,037	278,908	170,903	16,459	280,117	234,048
Revisions of previous estimates	(40,348)	(2,012)	(270,030)	(87,365)	(9,256)	(1,391)	42,514	(3,561)
Extensions, discoveries and other additions	793	34	4,693	1,610	20,056	379	35,552	26,360
Purchases of minerals in place	—	—	—	—	4,991	17,542	408,857	90,676
Sales of minerals in place	—	—	—	—	(28,890)	(12,326)	(51,065)	(49,727)
Production	(10,963)	(1,061)	(33,852)	(17,666)	(13,394)	(671)	(28,938)	(18,888)
End of year	93,892	16,953	387,848	175,487	144,410	19,992	687,037	278,908
Proved developed reserves	93,892	16,953	387,848	175,487	104,337	14,702	552,184	211,069
Proved undeveloped reserves	—	—	—	—	40,073	5,290	134,853	67,839
Total proved reserves	93,892	16,953	387,848	175,487	144,410	19,992	687,037	278,908

	Successor December 17, 2013 through December 31, 2013				Predecessor January 1, 2013 through December 16, 2013			
	Oil MBbls	NGL MBbls	Natural Gas MMcf	Total MBOE	Oil MBbls	NGL MBbls	Natural Gas MMcf	Total MBOE
Total proved reserves:								
Beginning of period	171,399	16,493	280,943	234,715	184,468	19,740	425,519	275,129
Revisions of previous estimates	—	—	—	—	(10,301)	(3,235)	(153,330)	(39,092)
Extensions, discoveries and other additions	—	—	—	—	9,360	1,595	29,756	15,913
Sales of minerals in place	—	—	—	—	(1,416)	(847)	(3,071)	(2,775)
Production	(496)	(34)	(826)	(667)	(10,712)	(760)	(17,931)	(14,460)
End of period	170,903	16,459	280,117	234,048	171,399	16,493	280,943	234,715

Proved developed reserves	113,717	7,977	202,798	155,494	114,213	8,011	203,624	156,161
Proved undeveloped reserves	57,186	8,482	77,319	78,554	57,186	8,482	77,319	78,554
Total proved reserves	170,903	16,459	280,117	234,048	171,399	16,493	280,943	234,715

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BERRY PETROLEUM COMPANY
SUPPLEMENTAL OIL & NATURAL GAS DATA (Unaudited) - Continued

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 decreased by approximately 103,421 MBOE to approximately 175,487 MBOE for the year ended December 31, 2015, from 278,908 MBOE for the year ended December 31, 2014. The year ended December 31, 2015, includes approximately 87,365 MBOE of negative revisions of previous estimates (71,389 MBOE due to lower commodity prices, 15,067 MBOE due to uncertainty regarding the Company’s future commitment to capital and 10,733 MBOE due to the SEC five-year development limitation on PUDs, partially offset by 9,824 MBOE of positive revisions due to asset performance). In addition, extensions and discoveries, primarily from 196 productive wells drilled during the year, contributed approximately 1,610 MBOE to the increase in proved reserves.

As a result of the uncertainty regarding the Company’s future commitment to capital, the Company reclassified all of its PUDs to unproved as of December 31, 2015. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for details regarding the Company’s going concern uncertainty.

The prices of oil, natural gas and NGL have continued to be volatile in 2016. In the future, if commodity prices continue to decline, the Company may have additional negative revisions which could have a material impact on its estimated quantities of oil, natural gas and NGL reserves. For information about potential risks that could affect the Company if lower commodity prices were to continue, see Item 1A. “Risk Factors.”

Proved reserves increased by approximately 44,860 MBOE to approximately 278,908 MBOE for the year ended December 31, 2014, from 234,048 MBOE for the year ended December 31, 2013. The year ended December 31, 2014, includes approximately 3,561 MBOE of negative revisions of previous estimates, due primarily to 3,547 MBOE of negative revisions due to asset performance and 2,910 MBOE due to the SEC five-year development limitation on PUDs, partially offset by 2,896 MBOE of positive revisions primarily due to higher natural gas prices. During the year ended December 31, 2014, properties acquired in the exchanges with ExxonMobil and Exxon XTO increased proved reserves by approximately 90,676 MBOE and the Permian Basin Assets Sale and properties relinquished in the exchanges with ExxonMobil and Exxon XTO decreased proved reserves by approximately 49,727 MBOE. In addition, extensions and discoveries, primarily from 411 productive wells drilled during the year, contributed approximately 26,360 MBOE to the increase in proved reserves. Proved reserves decreased by approximately 667 MBOE to approximately 234,048 MBOE at December 31, 2013, from 234,715 MBOE at December 16, 2013, due to production during the successor period.

Proved reserves decreased by approximately 40,414 MBOE to approximately 234,715 MBOE at December 16, 2013, from 275,129 MBOE at December 31, 2012. The period from January 1, 2013 through December 16, 2013, includes 39,092 MBOE of negative revisions of previous estimates, due primarily to the SEC five-year development limitation on PUDs. During the period from January 1, 2013 through December 16, 2013, two sales in the Permian Basin operating area decreased proved reserves by approximately 2,775 MBOE. In addition, extensions and discoveries, primarily from 340 productive wells drilled during the period, contributed approximately 15,913 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 Company is not subject to federal income taxes. Limited liability companies are subject to Texas margin tax; however, these amounts are not material. See Note 4 for additional information about income taxes.

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BERRY PETROLEUM COMPANY
SUPPLEMENTAL OIL & NATURAL GAS DATA (Unaudited) - Continued

	December 31, 2015 (in thousands)	2014	2013
Future estimated revenues	$5,483,899	$16,844,678	$17,863,984
Future estimated production costs	(3,458,415)	(7,742,035)	(6,654,536)
Future estimated development costs	(332,311)	(1,132,807)	(1,854,849)
Future net cash flows	1,693,173	7,969,836	9,354,599
10% annual discount for estimated timing of cash flows	(697,801)	(3,639,459)	(4,719,267)
Standardized measure of discounted future net cash flows	$995,372	$4,330,377	$4,635,332
Representative NYMEX prices: (1)			
Oil (Bbl)	$50.16	$95.27	$96.89
Natural gas (MMBtu)	2.59	4.35	3.67

(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:

	Successor December 31, 2015 (in thousands)	December 31, 2014
Standardized measure–beginning of year	$4,330,377	$4,635,332
Sales and transfers of oil, natural gas and NGL produced during the period	(207,125)	(794,337)
Changes in estimated future development costs	431,622	68,290
Net change in sales and transfer prices and production costs related to future production	(3,203,620)	(1,020,605)
Extensions, discoveries and improved recovery	20,345	674,392
Purchases of minerals in place	—	548,256
Sales of minerals in place	—	(486,903)
Previously estimated development costs incurred during the period	67,529	269,473
Net change due to revisions in quantity estimates	(544,334)	(66,696)
Accretion of discount	433,038	463,533
Changes in production rates and other	(332,460)	39,642
Net decrease	(3,335,005)	(304,955)
Standardized measure–end of year	$995,372	$4,330,377

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BERRY PETROLEUM COMPANY
SUPPLEMENTAL OIL & NATURAL GAS DATA (Unaudited) - Continued

(in thousands)	Successor December 17, 2013 through December 31, 2013	Predecessor January 1, 2013 through December 16, 2013
Standardized measure–beginning of period	$3,558,595	$3,833,415
Sales and transfers of oil, natural gas and NGL produced during the period	(30,208)	(703,597)
Changes in estimated future development costs	—	20,932
Net change in sales and transfer prices and production costs related to future production	(1,272)	(214,489)
Extensions, discoveries and improved recovery	—	189,625
Sales of minerals in place	—	(13,279)
Previously estimated development costs incurred during the period	—	401,791
Net change due to revisions in quantity estimates	—	(856,118)
Accretion of discount	19,184	496,718
Income taxes	1,109,522	237,117
Changes in production rates and other	(20,489)	166,480
Net increase (decrease)	1,076,737	(274,820)
Standardized measure–end of period	$4,635,332	$3,558,595

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.

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BERRY PETROLEUM COMPANY
SUPPLEMENTAL QUARTERLY DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the “Financial Statements” and “Notes to Financial Statements,” which are included in this Annual Report on Form 10-K in Item 8. “Financial Statements and Supplementary Data.”

Quarterly Financial Data

	Successor Quarters Ended			
	March 31	June 30	September 30	December 31
(in thousands)				
2015:				
Oil, natural gas and natural gas liquids sales	$156,586	$173,381	$140,252	$104,812
Electricity sales	5,151	6,609	8,610	4,174
Gains (losses) on oil and natural gas derivatives	3,267	(4,474)	27,664	2,718
Total revenues and other	169,281	177,890	179,307	115,176
Total expenses [1]	474,938	191,222	696,633	218,155
(Gains) losses on sale of assets and other, net	(4,473)	(811)	2,633	732
Net loss	(322,725)	(28,832)	(537,158)	(126,462)

	Successor Quarters Ended			
	March 31	June 30	September 30	December 31
(in thousands)				
2014:				
Oil, natural gas and natural gas liquids sales	$333,116	$360,380	$350,863	$254,043
Electricity sales	9,969	10,192	11,300	8,561
Gains (losses) on oil and natural gas derivatives	3,465	(25,562)	44,990	55,891
Total revenues and other	351,380	347,261	409,416	323,232
Total expenses [1]	244,156	240,116	225,834	488,741
Losses on sale of assets and other, net	3,367	4,257	49,011	64,151
Net income (loss)	79,698	79,008	115,165	(251,275)

(1) Includes the following expenses: lease operating, transportation, marketing, general and administrative, exploration, depreciation, depletion and amortization, impairment of long-lived assets and taxes, other than income taxes.

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company's reports under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, and LINN Energy's Audit Committee of the Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2015.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control Over Financial Reporting" in Item 8. "Financial Statements and Supplementary Data."

Changes in the Company's Internal Control Over Financial Reporting

The Company's management is also responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company's internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the financial statements for external purposes in accordance with accounting principles generally accepted in the U.S.

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

There were no changes in the Company's internal control over financial reporting during the fourth quarter of 2015 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

Intentionally omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10 K.

Item 11. Executive Compensation

Intentionally omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10 K.

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

Intentionally omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10 K.

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

Intentionally omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10 K.

Item 14. Principal Accounting Fees and Services

Prior to December 16, 2013, PricewaterhouseCoopers LLP served as Berry Petroleum Company's independent public accountant. Subsequent to December 16, 2013, KPMG LLP served as Berry Petroleum Company, LLC's independent public accountant. Prior to the LINN Energy transaction, the Berry Petroleum Company Audit Committee pre-approved all audit services and permissible nonaudit services provided by the independent auditor. The LINN Energy Audit Committee pre-approved all audit services and permissible nonaudit services provided by the independent auditor from the time of the LINN Energy transaction and for the remainder of 2013, and for the years 2014 and 2015.

The following provides the aggregate fees related to the audit and other services provided by KPMG LLP:

Audit Fees

The fees for professional services rendered by KPMG LLP for the audit of Berry Petroleum Company, LLC's financial statements for the each of the years ended December 31, 2015 and 2014, and the reviews of the financial statements included in any of its Quarterly Reports on Forms 10-Q for each of those years, were $775,000.

Audit-Related Fees

Berry Petroleum Company, LLC incurred no audit-related fees during the year ended December 31, 2015. KPMG LLP received fees of $25,000 for services in connection with procedures performed for other SEC filings during the year ended December 31, 2014.

Tax Fees

Berry Petroleum Company, LLC incurred no fees during the years ended December 31, 2015 and 2014, for tax-related services provided by KPMG LLP.

All Other Fees

Berry Petroleum Company, LLC incurred no other fees during the years ended December 31, 2015 and 2014, for any other services provided by KPMG LLP.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) - 1. Financial Statements:

All financial statements are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

(a) - 2. Financial Statement Schedules:

All schedules are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

(a) - 3. Exhibits:

The exhibits required to be filed by this Item 15 are set forth in the “Index to Exhibits” accompanying this report.

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SIGNATURES

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

BERRY PETROLEUM COMPANY, LLC

Date: March 28, 2016	By:	/s/ Mark E. Ellis Mark E. Ellis President and Chief Executive Officer
Date: March 28, 2016	By:	/s/ David B. Rottino David B. Rottino Executive Vice President and Chief Financial Officer
Date: March 28, 2016	By:	/s/ Darren R. Schluter Darren R. Schluter Vice President and Controller (Duly Authorized Officer and Principal Accounting Officer)

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

Signature	Title	Date
/s/ Mark E. Ellis Mark E. Ellis	President and Chief Executive Officer (Principal Executive Officer)	March 28, 2016
/s/ David B. Rottino David B. Rottino	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 28, 2016
/s/ Darren R. Schluter Darren R. Schluter	Vice President and Controller (Principal Accounting Officer)	March 28, 2016

LINN ACQUISITION COMPANY, LLC
As sole member of Berry Petroleum Company, LLC

/s/ David B. Rottino David B. Rottino	Executive Vice President and Chief Financial Officer	March 28, 2016

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Index to Exhibits

Exhibit Number		Description
3.1	—	Certificate of Formation of Berry Petroleum Company, LLC (incorporated herein by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on December 20, 2013)
3.2	—	Limited Liability Company Agreement of Berry Petroleum Company, LLC dated December 16, 2013 (incorporated herein by reference to Exhibit 3.2 to the Company’s Current Report on Form 8 K filed on December 20, 2013)
4.1	—	Indenture, dated June 15, 2006, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, relating to senior debt securities (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K filed on May 29, 2009)
4.2	—	Second Supplemental Indenture, dated November 1, 2010, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, including the form of 6.75% senior note due 2020 (incorporated by reference to Exhibit 4.2 to the Company’s Current Report on Form 8-K filed on November 1, 2010)
4.3	—	Third Supplemental Indenture, dated March 9, 2012, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, including the form of 6.375% senior note due 2022 (incorporated by reference to Exhibit 4.2 to the Company’s Current Report on Form 8-K filed on March 9, 2012)
10.1	—	Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 99.1 to the Registrant’s Current Report on Form 8-K filed on November 17, 2010)
10.2	—	First Amendment to the Second Amended and Restated Credit Agreement, dated April 13, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 13, 2011)
10.3	—	Second Amendment to the Second Amended and Restated Credit Agreement, dated June 17, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 4.1 to the Registrant’s Quarterly Report on Form 10 Q filed on November 3, 2011)
10.4	—	Third Amendment to the Second Amended and Restated Credit Agreement, dated October 26, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A. and the other lenders party thereto (incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on October 27, 2011)
10.5	—	Fourth Amendment to the Second Amended and Restated Credit Agreement dated April 13, 2012 by and among the Registrant and Wells Fargo Bank, N.A. and other lenders (incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on April 17, 2012)
10.6	—	Fifth Amendment to its Second Amended and Restated Credit Agreement, dated May 21, 2012, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10 Q filed on October 24, 2013)
10.7	—	Sixth Amendment to Second Amended and Restated Credit Agreement, dated October 22, 2013, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10 Q filed on October 24, 2013)
10.8	—	

Seventh Amendment to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated December 16, 2013, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated by reference to Exhibit 10.37 to Linn Energy, LLC's Annual Report on Form 10-K filed on February 27, 2014)

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Index to Exhibits - Continued

Exhibit Number		Description
10.9	—	Eighth Amendment to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated February 21, 2014, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated by reference to Exhibit 10.38 to Linn Energy, LLC's Annual Report on Form 10-K filed on February 27, 2014)
10.10	—	Ninth Amendment to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated April 30, 2014, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.4 to Linn Energy, LLC's Quarterly Report on Form 10-Q filed on May 1, 2014)
10.11	—	Tenth Amendment and Borrowing Base Agreement to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated as of May 12, 2015, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.2 to Linn Energy, LLC's Current Report on Form 8-K filed on May 15, 2015)
10.12	—	Eleventh Amendment and Borrowing Base Agreement, dated as of October 21, 2015, among Berry Petroleum Company, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and each of the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to Linn Energy, LLC's Current Report on Form 8-K filed on October 22, 2015)
10.13**	—	Carry and Earning Agreement, dated June 7, 2006, between Registrant and EnCana Oil & Gas (USA), Inc. (incorporated by reference to Exhibit 99.2 to the Registrant's Current Report on Form 8-K filed on June 19, 2006)
12.1*	—	Computation of Ratio of Earnings to Fixed Charges
23.1*	—	Consent of DeGolyer and MacNaughton
31.1*	—	Section 302 Certification of Chief Executive Officer
31.2*	—	Section 302 Certification of Chief Financial Officer
32.1*	—	Section 906 Certification of Chief Executive Officer
32.2*	—	Section 906 Certification of Chief Financial Officer
99.1*	—	2015 Report of DeGolyer and MacNaughton
101.INS†	—	XBRL Instance Document
101.SCH†	—	XBRL Taxonomy Extension Schema Document
101.CAL†	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE†	—	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

** Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

† Furnished herewith.