BERRY PETROLEUM CO
Form 10-K
March 05, 2015

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, 2014

.. 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 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

TABLE OF CONTENTS

Table of Contents

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:

Appraisal well. A well drilled in the vicinity of a discovery or wildcat well in order to evaluate the extent and importance of the discovery.

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 a 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 crude oil that can be extracted from an oil 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.

Mcf. One thousand cubic feet.

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

MBOE. One thousand barrels of oil equivalent.

MBOE/d. MBOE per day.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

Table of Contents
Glossary of Terms - Continued

MMcf. One million cubic feet.
MMcf/d. MMcf 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.
Mwh. One thousands kilowatts of electricity used continuously for one hour.
Mwh/d. Mwh per day.
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. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
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%.

Table of Contents
Glossary of Terms - Continued

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.

Table of Contents

Part I

Item 1. Business

This Annual Report on Form 10-K contains forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed 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), east Texas and Colorado (Piceance Basin). The Company previously had properties in the Permian Basin that were divested during 2014 (see "Recent Developments" below for additional information).

Proved reserves at December 31, 2014, were approximately 279 MMBOE, of which approximately 52% were oil, 41% were natural gas and 7% were natural gas liquids ("NGL"). Approximately 76% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $4.3 billion. At December 31, 2014, the Company operated 5,808 or approximately 96% of its 6,035 gross productive wells and had an average proved reserve-life index of approximately 15 years, based on the December 31, 2014, reserve report and year-end 2014 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 high operating margins and the financial flexibility to respond to commodity price and localized operating environments.

Table of Contents
Item 1. Business - Continued

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 high-return 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 15 years as of December 31, 2014.
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. The Company finances its drilling and development program primarily through its 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
Exchanges of Properties
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 in exchange for properties in California's South Belridge Field. As of the exchange date, the Company received approximately 5 MMBOE of proved reserves while Exxon Mobil Corporation received approximately 40 Bcfe of proved reserves.
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. (collectively, "ExxonMobil"), in exchange for properties in the Hugoton Basin. As of the exchange date, the Company received approximately 514 Bcfe of proved reserves while ExxonMobil received approximately 20,000 net acres in the Midland Basin, which are located primarily in Midland, Martin and Glasscock counties and approximately 154 Bcfe of proved reserves.
Divestiture
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 (the "Permian Basin Assets Sale"). Cash proceeds from the sale of these properties were approximately $351 million, net of costs to sell of approximately $2 million. The net cash proceeds from the Permian Basin Assets Sale were advanced by the Company to a subsidiary of LINN Energy. These proceeds must 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, as defined in Note 3.
Properties
The Company currently has five operating areas in the U.S.: California, Hugoton Basin, Uinta Basin, East Texas and Piceance Basin. The Company previously had properties in the Permian Basin that were divested during 2014. The Permian Basin operating area produced 7.2 MBOE/d or 14% of the Company's 2014 average daily production.

Table of Contents

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 45% of total proved reserves at December 31, 2014, of which 72% were classified as proved developed. This operating area produced 26.0 MBOE/d or 50% of the Company’s 2014 average daily production.
Hugoton Basin
The Company’s Hugoton Basin properties, acquired in an exchange with ExxonMobil in August 2014, 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 33% of total proved reserves at December 31, 2014, of which 79% were classified as proved developed. This operating area produced 4.0 MBOE/d or 8% of the Company’s 2014 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 13% of total proved reserves at December 31, 2014, of which 72% were classified as proved developed. This operating area produced 10.9 MBOE/d or 21% of the Company’s 2014 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 5% of total proved reserves at December 31, 2014, all of which were classified as proved developed. This operating area produced 1.7 MBOE/d or 3% of the Company’s 2014 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 4% of total proved reserves at December 31, 2014, of which 68% were classified as proved developed. This operating area produced 1.9 MBOE/d or 4% of the Company’s 2014 average daily production.

Table of Contents
Item 1. Business - Continued

Drilling and Acreage
The following sets forth the wells drilled during the periods indicated ("gross" refers to the total wells in which the Company had a working interest and "net" refers to gross wells multiplied by the Company's working interest):

	Year Ended December 31,		
	2014	2013	2012
Gross wells:			
Productive	411	340	467
Dry	—	—	3
	411	340	470
Net development wells:			
Productive	407	311	431
Dry	—	—	3
	407	311	434
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	5
	—	—	5

As of December 31, 2014, the Company had 93 gross (92 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 sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2014. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries. Gross wells refer to the total number of producing wells in which the Company has an interest and net wells refer to the sum of its fractional working interests owned in gross wells.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	3,187	2,774	2,621	1,630	5,808	4,404
Nonoperated	19	6	208	26	227	32
	3,206	2,780	2,829	1,656	6,035	4,436

Developed and Undeveloped Acreage
The following sets forth information relating to leasehold acreage as of December 31, 2014:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage [(1)]	590	443	140	90	730	533

(1) Excludes approximately 47,000 undeveloped net acres subject to drill-to-earn agreements.

Table of Contents
Item 1. Business - Continued

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:

	2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	29	16	4	2	22	11

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. However, the Company currently has no plans to develop or extend the lease terms on approximately 15,200 net acres related to leases that are due to expire in 2015.

Reserve Data

Proved Reserves

The following sets forth estimated proved oil, natural gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2014, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:		
Oil (MMBbls)	104	
NGL (MMBbls)	15	
Natural gas (Bcf)	552	
Total (MMBOE)	211	
Estimated proved undeveloped reserves:		
Oil (MMBbls)	40	
NGL (MMBbls)	5	
Natural gas (Bcf)	135	
Total (MMBOE)	68	
Estimated total proved reserves (MMBOE)	279	
Proved developed reserves as a percentage of total proved reserves	76	%
Standardized measure of discounted future net cash flows (in millions) [1]	$4,330	
Representative NYMEX prices: [2]		
Oil (Bbl)	$95.27	
Natural gas (MMBtu)	$4.35	

[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, 2014, the Company's proved undeveloped reserves ("PUDs") decreased to 68 MMBOE from 79 MMBOE at December 31, 2013, representing a decrease of 11 MMBOE. The decrease was due to 27 MMBOE of PUDs developed during 2014 and 24 MMBOE related to the Permian Basin Assets Sale and properties relinquished in the exchanges with Exxon Mobil Corporation (see Note 2), partially offset by 20 MMBOE added primarily as a result of the properties acquired in the exchanges with Exxon Mobil Corporation, 15 MMBOE added as a result of the Company's drilling activities and 5 MMBOE of positive revisions primarily due to higher natural gas prices partially offset by negative revisions due to asset performance and the SEC five-year development limitation.

During the year ended December 31, 2014, the Company incurred approximately $269 million in capital expenditures to convert 27 MMBOE of reserves that were classified as PUDs at December 31, 2013, to proved developed reserves. Based on the December 31, 2014 reserve reports, the amounts of capital expenditures estimated to be incurred in 2015, 2016 and 2017 to develop the Company's PUDs are approximately $75 million, $214 million and $226 million, respectively. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices. None of the 68 MMBOE of PUDs at December 31, 2014, has remained undeveloped for five years or more. All PUD properties are included in the Company's current five-year development plan.

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.

Table of Contents

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 which 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, 2014, 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 which 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, 2014, 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.

Table of Contents
Item 1. Business - Continued

The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2014:

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)	$31,906
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	6/2009 to 11/2019	1.09	(1)	19,420
Questar Pipeline	Chipeta Plant, UT	Various UT locations	6,200	2/2013 to 2/2021	0.17		2,039
Ruby Pipeline	Opal, WY	Malin, OR	37,857	8/2011 to 7/2021	0.95		86,419
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	37,857	8/2011 to 7/2021	0.31		27,900
Questar Pipeline	Chipeta Plant, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.26		3,679
Questar Pipeline	Brundage Canyon, UT	Chipeta Plant, UT	15,640	9/2013 to 8/2023	0.17		9,036
Total							$180,399

(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, 2014.

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 consuming less fuel.

Conventional Steam Generation

The Company also owns 68 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 the Company 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 net electrical generation of the Company’s three cogeneration facilities, which are centrally located on certain of the Company’s oil producing properties, was approximately 91 MW as of December 31, 2014. The steam generated by each facility is capable of being delivered to numerous wells that require steam for the enhanced oil recovery process. The sole

Table of Contents
Item 1. Business - Continued

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"). Under these power purchase agreements ("PPA"), the Company is paid an amount that reflects the utility's Short Run Avoided Cost ("SRAC") of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility.

Beginning in 2015, the energy prices paid under the contracts for the Company's Cogen 18 and Cogen 38 facilities will be based on market prices for electricity in California.

The Company's legacy PPA for its Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. The Company participated in a competitive solicitation for the sale of energy and capacity from its Cogen 38 facility, which resulted in the execution of an RFO PPA with Edison that is pending CPUC approval. The Company's transition PPA with PG&E will remain in effect until June 2015.

The Company's legacy PPA for its Cogen 42 facility expired in May 2012, at which time a transition PPA with Edison became effective. The transition PPA terminated on July 1, 2014, upon the effectiveness of a seven-year RFO PPA for the Cogen 42 facility pursuant to a competitive solicitation.

The Company's legacy PPA for its Cogen 18 facility terminated on September 30, 2012 and was replaced with a new Public Utilities Regulatory Policy Act of 1978, as amended ("PURPA") PPA with PG&E, effective 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 PURPA.

Under the PURPA PPA for the Company's Cogen 18 facility and the transition PPA for its Cogen 38 facility, the Company is paid the CPUC-determined SRAC energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPA for the Company's Cogen 42 facility, 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 as of December 31, 2014:

Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day in 2014
Cogen 38	Transition	PG&E	June 2015 [1]	35	—	17,100
Cogen 18	PURPA	PG&E	Sept. 2019	10	6	6,600
Cogen 42	RFO	Edison	July 2021	37	3	13,700

[1] Pending CPUC approval, a new seven-year RFO PPA with Edison will become effective on July 1, 2015.

9

Table of Contents
Item 1. Business - Continued

Principal Customers
For the year ended December 31, 2014, sales to Exxon Mobil Corporation and Phillips 66 accounted for approximately 39% and 11%, respectively, of the Company's total production volumes. 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.
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 and results of operations. 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. Oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which do not materially interfere with the use of or affect the carrying value of the properties.
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.

Table of Contents

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;
- 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 lying 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 two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs. 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. 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 thereafter 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 continues to assess the impact of these regulations on its operations, including the cost to acquire allowances and to reduce emissions. The Company's cost of acquiring compliance instruments in 2014 was in the range of $1.50 to $2.50 per barrel of 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, on May 16, 2013, the Department of the Interior's Bureau of Land Management ("BLM") issued a proposed rule that, if adopted, would require 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 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 adopted, these 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.

Table of Contents
Item 1. Business - Continued

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 entire state of New York and certain communities in Colorado and Texas have enacted bans or moratoria on hydraulic fracturing, to which legal challenges are 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 and results of operations.

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 as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. The Company does not expect these developments to have a material adverse effect on its business, financial condition, results or operations or cash flows.

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 as well as 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. In January 2015, the EPA announced plans to issue a proposed rule in summer 2015 governing methane emissions from the oil and natural gas industry. The BLM is also expected to address methane emissions from the oil and natural gas industry on federal 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, 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. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

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. Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue and the Bureau of Indian Affairs, as well as the American Indian Environmental Office of the U.S. Environmental Protection Agency, concurrently with each Indian tribe, promulgate and enforce regulations pertaining to oil and natural gas operations on Indian lands. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, tribal employment and contractor preferences and numerous other matters.

Tribal authority over oil and natural gas operations is often limited by various federal statutes and may be subject to oversight by the Bureau of Indian Affairs and Bureau of Land Management. However, each tribe is recognized by the federal government as a “domestic dependent nation” with the inherent authority to enact and enforce certain other laws and regulations, as long as such laws are not superseded by or in conflict with federal law. These tribal laws and regulations include various fees, taxes, authorizations, requirements to employ tribal members and numerous other conditions that apply to lessees, operators and contractors conducting operations on Indian lands. 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.

Therefore, the Company may be subject to various laws and regulations pertaining to tribal surface ownership. In addition, the Company may be subject to the terms and conditions of oil and natural gas leases on Indian lands, as well as fees, taxes, obligations and other issues unique to oil and natural gas ownership and operations on Indian lands. 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, 2014, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of the Company’s facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2015 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of 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.

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.

Table of Contents
Item 1. Business - Continued

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;
- plans, objectives, expectations and intentions; and
- integration of the assets and operations acquired in the exchanges of properties, 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 listed in the "Risk Factors" section 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.

The borrowing base under our Credit Facility is subject to redetermination and any reduction in the borrowing base may result in our having to repay indebtedness under our Credit Facility earlier than anticipated.

Our Credit Facility, as defined in Note 3, is subject to scheduled redeterminations of its borrowing base, based primarily on reserve reports using lender commodity price expectations at such time, semi-annually in April and October. Additionally the lenders under the Credit Facility have the ability to request an interim redetermination of the borrowing base once between scheduled redeterminations. If current low commodity prices continue through such redetermination events, the borrowing base under the Credit Facility may be reduced. Upon any such potential reduction, any outstanding indebtedness in excess of the new borrowing base may become due within a short time span or we must pledge other properties as additional collateral. We currently have limited unpledged properties.

In particular, because the Credit Facility is effectively fully drawn, any such reduction in the Credit Facility's borrowing base may require us to make mandatory prepayments under the Credit Facility to the extent existing indebtedness under the Credit Facility exceeds the new borrowing base, or our indirect parent LINN Energy, LLC ("LINN Energy") may post restricted cash on our behalf. If we are required to repay indebtedness under our Credit Facility earlier than anticipated due to a borrowing base redetermination, it may be necessary to use cash that would otherwise be available for capital expenditures to repay such indebtedness. In addition, any failure to repay indebtedness in excess of our borrowing base would constitute an event of default under the Credit Facility, and could cause a cross-default under our other outstanding indebtedness.

Commodity prices are volatile, and a significant decline in commodity prices for a prolonged period would reduce our revenues, profitability and cash flow.

Our revenues, profitability and cash flow depend on the prices of and demand for oil, natural gas and NGL. The oil, natural gas and NGL market is very volatile and a drop in prices can 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 cash flow. 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.

In the fourth quarter of 2014 and subsequent to December 31, 2014, the prices of oil, natural gas and NGL have been extremely volatile and declined significantly. Downward pressure on commodity prices has continued in 2015 and may continue for the foreseeable future. Declines in oil and natural gas prices would reduce our revenues and could also reduce the amount of oil and natural gas that we can produce economically, which could reduce our recognized reserve quantities and could materially and adversely affect our financial condition, results of operations and cash flows.

Future price declines or downward reserve revisions may result in a write-down of our asset carrying values, which could adversely affect our results of operations.

Declines in oil, natural gas and NGL prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our properties for impairments. We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore would require a write-down. We have incurred impairment charges in the past and may do so in the future. Any impairment could be substantial and have a material adverse effect on our results of operations in the period incurred.

Table of Contents
Item 1A. Risk Factors - Continued

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could have an adverse impact on our ability to hedge risks associated with our business and on our results of operations and cash flows.
Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) establishes federal oversight and regulation of the over-the-counter (“OTC”) derivatives market and entities, such as us, that participate in that market. The provisions of that title of the Dodd-Frank Act and the rules of the Commodity Future Trading Commission (“CFTC”) and the SEC adopted and proposed to be adopted thereunder, regulate certain swaps entities, require clearing of certain swaps by clearing organizations and execution of certain swaps on contract markets or swap execution facilities, and require certain reporting and recordkeeping of swaps. They also give the CFTC the authority to establish limits on the positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities held by market participants, with exceptions for certain bona fide hedging transactions. The CFTC’s rules establishing position limits were vacated by a federal district court in September 2012. However, on November 5, 2013, the CFTC proposed new position limits rules that would modify and expand the applicability of position limits on certain core futures and equivalent swaps contracts for or linked to certain physical commodities that market participants could hold with exceptions for certain bona fide hedging transactions.
The CFTC has designated certain interest rate swaps and certain credit default swaps for mandatory clearing and set compliance dates for three different categories of market participants who are parties to such swaps, the earliest of which was March 11, 2013, and the latest of which was September 9, 2013. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require our counterparties to require that we enter into credit support documentation and/or post initial and variation margin; however, the proposed margin rules are not yet final, and therefore the application of those provisions to us is uncertain at this time. Provisions of the Dodd-Frank Act may also cause our derivatives counterparties to spin off some or all of their derivatives activities to a separate entity, which could be our counterparty in future swaps and which entity may not be as creditworthy as the current counterparty.
The Dodd-Frank Act’s swaps regulatory provisions and the related rules could significantly increase the cost of derivatives contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our results of operations and cash flows may become more volatile and could be otherwise adversely affected.
In addition to the Dodd-Frank Act, in 2012, the European Market Infrastructure Regulation (“EMIR”) became effective. EMIR includes regulations related to the trading, reporting and clearing of derivatives and the regulations thereunder may impact our ability to maintain or enter into derivatives with certain of our European counterparties.
Unless we replace our reserves, our reserves and production will decline, which would adversely affect our revenues and cash flows.
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 and under other circumstances. Thus, our future oil, natural gas and NGL reserves and production and, therefore, our cash flows and income, are highly dependent on our success in efficiently developing our current reserves. We may not be able to develop additional reserves to replace our current and future production at acceptable costs, which would adversely affect our revenues and cash flows.

Table of Contents

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.

Although proved reserves were estimated in accordance with SEC regulations, 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, there was a steep decline in commodity prices during the fourth quarter of 2014. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas prices decreased approximately 42% and 30%, respectively, to $53.27 per Bbl for oil and $2.89 per MMBtu for natural gas at December 31, 2014.

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. We do not have any additional borrowing capacity under our Credit Facility and do not intend to obtain additional borrowing capacity or access the capital markets to fund our operations.

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. We do not intend to obtain additional borrowing capacity under our Credit Facility or access the capital markets separately from LINN Energy. We intend to finance our operations, including our future capital expenditures, with net cash provided by operating activities and funding from LINN Energy. Our cash provided by operating activities is 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 develop existing reserves.

Table of Contents

If our revenues or the borrowing base under our Credit Facility decreases as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, or LINN Energy determines not to fund our capital expenditures, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our Credit Facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt financing on terms favorable to us, or at all. If net cash provided by operating activities or funding from LINN Energy is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our development operations, which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

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. 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. In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of such reserves could also have a negative effect on the borrowing base under our Credit Facility.

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. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial condition, results of operations and cash flows.

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 revenue 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, as well as trucking and rail systems. 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.

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

We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For example, approximately 39% of our total production volumes are sold to one refiner in California. 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.

20

Table of Contents
Item 1A. Risk Factors - Continued

We may experience difficulties in integrating assets we acquire from third parties, which could cause us to fail to realize many of the anticipated potential benefits of those acquisitions.

As part of our exchanges of properties with Exxon Mobil Corporation, we acquired oil and natural gas properties in the Hugoton Basin and California. Achieving the anticipated benefits of these acquisitions will depend in part on whether we are able to integrate these assets in an efficient and effective manner. We may not be able to accomplish this integration process smoothly or successfully. The difficulties of integrating these assets with our business potentially will include, among other things, the necessity of coordinating geographically separated assets and the integration of certain operations, data systems and processes, which may require the dedication of significant management resources and which may temporarily distract management's attention from our day-to-day business. An inability to realize the full extent of the anticipated benefits of these acquisitions, as well as any delays encountered in the transition process, could have an adverse effect on our revenues, level of expenses and operating results.

LINN Energy may be unable to retain key employees.

Our future success will depend in part on LINN Energy's ability to retain key employees. During 2014, we and LINN Energy acquired several new properties, and LINN Energy hired employees associated with those properties. Additionally, in the fourth quarter of 2014, commodity prices decreased significantly. Key employees may depart because of issues relating to the uncertainty and difficulty of integration or during times of commodity price volatility. Accordingly, no assurance can be given that LINN Energy will be able to retain key employees to the same extent as in the past.

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 business, financial position, results of operations and cash flows.

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 business activities, financial condition, results of operations and cash flows. Increased costs could include losses from personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of

Table of Contents

wells and regulatory penalties. We ordinarily maintain insurance against certain losses and liabilities arising from our operations. However, it is impossible to insure against all operational risks in the course of our business. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business activities, financial position, results of operations and cash flows.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations such as geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. These types of shortages or price increases could restrict our ability to drill planned wells, conduct planned operations, or could otherwise materially and adversely affect our financial condition, results of operations and cash flows.

We may incur losses as a result of title deficiencies.

The existence of a material title deficiency in our properties can reduce the value or render a property worthless, thus having a material adverse effect on our business, financial condition, results of operations and cash flows. Title insurance covering mineral leaseholds is not always available, and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In cases involving material title problems, a prospect can become undrillable, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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, provide approximately 14% of our steam capacity as of December 31, 2014. 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

Table of Contents

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."

Our use of hedging transactions could result in financial losses or reduce our earnings.

To reduce our exposure to fluctuations in oil and natural gas prices, we have entered into and expect in the future to enter into derivative instruments (or hedging contracts) for a portion of our anticipated oil and natural gas production or natural gas consumption. Our hedging transactions expose us to certain risks and financial losses, including, among others, the risk that we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions, and that we may hedge too much or too little production or consumption depending on how oil and natural gas prices fluctuate in the future.

As of December 31, 2014, we had 1,095 MBbls of oil production volumes hedged for 2015 but no production volumes hedged for years subsequent to 2015.

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, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

A widening of commodity basis differentials may materially and adversely impact our revenues and our economics.

The oil and natural gas we produce is priced in local markets where production occurs and is based on local or regional supply and demand factors as well as other local market dynamics such as regional storage capacity and transportation. The prices that we receive for our oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX or Brent, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a basis differential.

We may be unable to accurately predict oil and natural gas basis differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as refinery capacity, pipeline takeaway capacity and specifications, localized storage capacity, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be materially and adversely impacted by a widening basis differential on the products we sell. Our commodity hedging contracts are typically based on WTI or other oil or natural gas index prices. As a result, we may be subject to "basis risk" if the basis differential on products we sell widens from the benchmarks used in our commodity hedging contracts.

Additionally, regional capacity and storage issues may cause benchmark prices to become disconnected from regional oil and natural gas prices which may materially and adversely affect our ability to hedge using contracts based on such indexes. Insufficient pipeline capacity, storage capacity or trucking or rail transportation capability and the lack of demand in any given operating area may cause the basis differential to widen in that area compared to other oil and natural gas producing areas. Increases in the basis differential between benchmark prices for oil and natural gas and the wellhead price we receive could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our limited ability to hedge our NGL production and commodity basis differentials could adversely impact our net cash provided by operating activities and results of operations.

A liquid, readily available and commercially viable market for hedging NGL and commodity basis differentials has not developed in the same way that exists for crude oil and natural gas priced at WTI and Henry Hub, respectively. The current direct NGL and commodity basis differential hedging market is constrained in terms of price, volume, duration and number of counterparties. This limits both our ability to hedge our NGL production and price difference based on point of sale effectively or at all. If the current price levels for NGL continue or decrease in the future or the commodity basis differentials versus WTI or Henry Hub negatively increase, our net cash provided by operating activities and results of operations would be affected.

Table of Contents

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 becomes 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.

Competition within our industry is intense and may materially and adversely affect our operations.

We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies in acquiring desirable oil and natural gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and natural gas companies in the marketing and sale of oil and natural gas. Many of our competitors are larger, fully integrated energy companies that have financial, staff and other resources substantially greater than ours, may be less leveraged than we are and have a lower cost of capital. As a result, our competitors may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Our competitors may be able to expend greater resources on changing technologies that are increasingly important to efficiency and success in the industry and may also have a greater ability to continue drilling activities during periods of low oil and natural gas prices or to absorb the burden of present and future federal, state, local and other laws and regulations. In addition, oil and natural gas producers are increasingly facing competition from providers of alternative energy, and government policy may favor those competitors in the future. We can give no assurance that we will be able to compete effectively in the future, which could materially and adversely affect our financial condition, results of operations and cash flows.

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."

24

Table of Contents
Item 1A. Risk Factors - Continued

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 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. For a description of the laws and regulations that affect us, see Item 1. “Business – Environmental Matters and Regulation.”

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

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 Environmental Protection Agency (“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, on May 16, 2013, the Department of the Interior’s Bureau of Land Management (“BLM”) issued a proposed rule that, if adopted, would require 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 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 adopted, these 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 entire state of New York and certain communities in Colorado and Texas have enacted bans or moratoria on hydraulic fracturing, to which legal challenges are pending. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect our revenues and results of operations.

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 as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells.

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

In December 2009, the 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 two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the CAA’s Prevention of Significant Deterioration and Title V permitting programs. 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. 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.

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 we are a part, as our California operations emit GHGs. The cap will decline annually thereafter through 2020. We are required to remit compliance instruments for each metric ton of GHG that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Under Assembly Bill 32, we will be granted a certain number of California carbon allowances (“CCA”) and we will need to purchase CCAs and/or offset credits to cover the remaining amount of our emissions. Compliance with Assembly Bill 32 could significantly increase our capital, compliance and operating costs and could also reduce demand for the oil and natural gas we produce. We continue to assess the impact of these regulations on our operations, including the cost to acquire allowances and to reduce emissions. Our cost of acquiring compliance instruments in 2014 was in the range of $1.50 to $2.50 per barrel of 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 our ability to limit our 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.

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

Recent regulatory changes in California have impacted our Diatomite production. 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”). We 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 our operating costs for our Diatomite assets. The requirements continued to affect our operations through 2014, 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. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets, which could have a material adverse effect on our business, financial position, results of operations and cash flows.

Table of Contents
Item 1A. Risk Factors - Continued

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 have a substantial amount of debt and the cost of servicing that debt could adversely affect our business.
We have a substantial amount of indebtedness. As of January 31, 2015, we had approximately $2.1 billion of total outstanding debt, including $1.2 billion of outstanding borrowings under our Credit Facility. Total lender commitments under the facility are $1.2 billion, and the borrowing base is $1.4 billion. Currently we have no availability to borrow under our Credit Facility. Our level of indebtedness relative to our proved reserves and the significant demands on our cash resources could have important effects on our business. The terms of the agreements governing our indebtedness:

- require us to make principal payments under our Credit Facility if the quantity of proved reserves attributable to our oil and natural gas properties are insufficient to support our level of borrowings under our Credit Facility or if we sell assets subject to the borrowing base under our Credit Facility;
- limit our financial flexibility, including our ability to borrow additional funds, pay dividends, make capital expenditures and other investments;
- increase our interest expense if interest rates increase; and
- result in an event of default upon a failure to comply with financial covenants contained in the agreements governing our indebtedness which, if not cured or waived, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities may depend upon our future performance and our, or LINN Energy's, ability to refinance our debt as it becomes due. Our future operating performance and our, or LINN Energy's, ability to refinance our indebtedness will be affected by economic and capital markets conditions, oil and natural gas prices, our, and LINN Energy's, business, financial condition, results of operations and cash flows and other factors, many of which are beyond our, or LINN Energy's, control. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include reducing or delaying capital expenditures, selling assets or restructuring or refinancing debt. There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.
Restrictions in the agreements governing our indebtedness could limit our ability to respond to changing conditions.
Agreements governing our outstanding debt restrict our ability to, among other things:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase debt that is junior in right of payment to our senior notes;
- make loans and other types of investments;
- incur liens;
- sell or otherwise dispose of assets;
- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- make capital expenditures or acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

Although we currently do not have any availability under our Credit Facility, our future ability to borrow under our Credit Facility is dependent upon the quantity of proved reserves attributable to our oil and natural gas properties and the respective projected commodity prices as determined by the lenders under our Credit Facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure that we will satisfy such covenants and requirements.

Table of Contents

The level and terms of LINN Energy's indebtedness and its credit ratings could have a material adverse effect our business, financial condition, results of operations and cash flows.

The level and terms of LINN Energy's indebtedness may limit its ability to borrow additional funds and could have a material adverse effect our business, financial condition, results of operations and cash flows. If LINN Energy were to default under its debt obligations, its creditors could attempt to assert claims against our assets during the litigation of their claims against LINN Energy and an event of default under LINN Energy's credit facility constitutes an event of default under our Credit Facility. The defense of any such claims could be costly and could materially impact our financial condition, even absent any adverse determination. If these claims were successful, our ability to meet our obligations to our creditors and finance our operations could be materially and adversely affected. If one or more credit rating agencies were to downgrade LINN Energy's credit rating, we could experience an increase in our borrowing costs. Such a development could adversely affect our ability to operate our business and to meet our financial obligations.

A downgrade in our credit rating could materially and adversely impact our cost of and ability to access capital.

Our and LINN Energy's access to credit and capital markets also depends 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, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access capital or financial markets in the future, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

Our and LINN Energy's ability to access the capital and credit markets to raise capital and borrow on favorable terms will be affected by disruptions in the capital and credit markets, which could adversely affect our operations, and our ability to finance our debt may be reduced.

Disruptions in the capital and credit markets, in particular with respect to companies in the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Recent developments in commodity prices, among other things, may cause our lenders to increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, our ability to finance our debt may be reduced.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

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 information concerning 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.

28

Table of Contents

Item 3. Legal Proceedings

Department of the Interior Notice of Proposed Debarment

In June 2012, the Company received a Notice of Proposed Debarment issued by the United States Department of the Interior ("DOI"). Pursuant to the notice, the DOI's Office of the Inspector General proposed to debar the Company from participation in certain federal contracts and assistance activities, including oil and natural gas leases, for a period of three years. The basis for the proposed debarment relates to the Company's purported noncompliance with Bureau of Land Management ("BLM") regulations relating to the operation of certain equipment and the submission of related site facility diagrams in its Uinta operations. In 2011, the Company entered into a settlement agreement with the BLM and paid a $2 million civil penalty relating to the matter. The Company contested the proposed debarment and believes the matter is without merit; nevertheless, in June 2013, the Company entered into an agreement with the DOI to resolve the matter administratively through an independent compliance review. The independent compliance review has concluded and the final compliance review reports have been submitted to the DOI. The Company has been informed that the DOI intends to make follow-up inquiries to the Company in the near future, but has not received any further communications to date.

Royalty Class Action

The Company is a defendant in a certain statewide royalty class action case. The parties entered into a settlement agreement to settle past claims for approximately $2.4 million, which the Court approved on October 29, 2014. On December 17, 2014, the Company made a one-time lump sum payment of $2.4 million for damages related to production through April 30, 2014. On December 29, 2014, the Court issued an Order dismissing the matter with prejudice. Per the parties' settlement agreement, the Company has agreed to a new methodology for calculating royalty payments beginning May 1, 2014.

Other

The Company is involved in various other 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

Table of Contents

Part II

Item 5. Market for the Registrant's Common Equity, Related Shareholder 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 regular quarterly dividends of $0.08 per share in March, June, September and December of 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 "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(2) of the Securities Act as these transactions were by an issuer not involving a public offering (see LINN Energy and LinnCo's joint proxy statement/prospectus for their 2013 annual meetings for additional information).

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.

Table of Contents

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 "Notes to Financial Statements," 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 that reflect the Company's future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside the Company's control. The Company's actual results could differ materially from those discussed in these 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 discussed below and elsewhere in this Annual Report on Form 10 K, particularly in Item 1A. "Risk Factors." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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 and Note 2). 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, East Texas and Piceance Basin. The Company previously had properties in the Permian Basin that were divested during 2014. The Permian Basin operating area produced 7.2 MBOE/d or 14% of the Company's 2014 average daily production. For a discussion of the Company's five operating areas, see Item 1. "Business."

Results for 2014 included the following:

- oil, natural gas and NGL sales of approximately $1.3 billion for the year ended December 31, 2014, compared to $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;
- average daily production of 51.7 MBOE/d for the year ended December 31, 2014, compared to 44.5 MBOE/d and 41.3 MBOE/d for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively;
- net income of approximately $23 million for the year ended December 31, 2014, compared to a net loss of $20 million and net income of $93 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively;
- net cash provided by operating activities of approximately $583 million for the year ended December 31, 2014, compared to $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;
- capital expenditures, excluding acquisitions, of approximately $574 million for the year ended December 31, 2014, compared to $17 million and $595 million for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, respectively; and
- 411 wells drilled (all successful) for the year ended December 31, 2014, compared to 340 wells drilled (all successful) for the year ended December 31, 2013.

Table of Contents

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

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.

Exchanges of Properties

On November 21, 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 in exchange for properties in California’s South Belridge Field. As of the exchange date, the Company received approximately 5 MMBOE of proved reserves while Exxon Mobil Corporation received approximately 40 Bcfe of proved reserves.

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. (collectively, “ExxonMobil”), in exchange for properties in the Hugoton Basin. As of the exchange date, the Company received approximately 514 Bcfe of proved reserves while ExxonMobil received approximately 20,000 net acres in the Midland Basin, which are located primarily in Midland, Martin and Glasscock counties and approximately 154 Bcfe of proved reserves.

Divestiture

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 (the “Permian Basin Assets Sale”). Cash proceeds from the sale of these properties were approximately $351 million, net of costs to sell of approximately $2 million. The net cash proceeds from the Permian Basin Assets Sale were advanced by the Company to a subsidiary of LINN Energy. These proceeds must 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, as defined below.

Financing Activities

The Company’s Second Amended and Restated Credit Agreement (“Credit Facility”) has a borrowing base of $1.4 billion, subject to lender commitments. At January 31, 2015, lender commitments under the facility were $1.2 billion but there was less than $1 million of available borrowing capacity, including outstanding letters of credit. In February 2014, the Company entered into an amendment to the Credit Facility to amend the terms of certain financial and reporting covenants, among other items. In April 2014, the Company entered into an amendment to the Credit Facility to extend the maturity date from May 2016 to April 2019 and to amend the terms of certain financial covenants and definitions, among other items.

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

The next semi-annual redetermination of the borrowing base is scheduled to occur in April 2015. Continued lower commodity prices may result in a decrease in the borrowing base at that time. In February 2015, LINN Energy and Berry entered into a parent support agreement under which LINN Energy agreed, in the event the borrowing base is reduced below the amount of borrowings outstanding, to either make principal repayments or provide additional collateral to the lenders, including through posting restricted cash on Berry's behalf to address the shortfall, subject to LINN Energy's credit facility.

On May 30, 2014, in accordance with the provisions of the indenture related to its 10.25% senior notes due June 2014 (the "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.

Table of Contents

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

Results of Operations

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

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Revenues and other:				
Oil sales	$1,146,047	$45,655	$1,006,539	$855,290
Natural gas sales	125,539	3,416	67,877	55,573
NGL sales	26,816	1,253	28,829	26,398
Total oil, natural gas and NGL sales	1,298,402	50,324	1,103,245	937,261
Electricity sales	40,022	1,444	33,992	29,940
Gains (losses) on oil and natural gas derivatives	78,784	(5,049)	(34,711)	64,620
Marketing and other revenues	14,081	399	8,776	9,305
	1,431,289	47,118	1,111,302	1,041,126
Expenses:				
Lease operating expenses	364,540	15,410	295,811	232,266
Electricity generation expenses	28,171	1,257	22,485	19,975
Transportation expenses	41,842	2,576	46,774	39,531
Marketing expenses	8,084	376	7,593	6,873
General and administrative expenses	102,787	20,298	122,991	71,564
Exploration costs	—	—	24,048	21,010
Depreciation, depletion and amortization	302,353	10,845	279,757	227,700
Impairment of long-lived assets	253,362	—	—	—
Taxes, other than income taxes	97,708	2,130	57,063	39,757
(Gains) losses on sale of assets and other, net	120,786	10,208	(23)	(1,782)
	1,319,633	63,100	856,499	656,894
Other income and (expenses)	(88,991)	(3,991)	(96,076)	(124,572)
Income (loss) before income taxes	22,665	(19,973)	158,727	259,660
Income tax expense	69	—	65,280	88,121
Net income (loss)	$22,596	$(19,973)	$93,447	$171,539

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

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Average daily production:				
Oil (MBbls/d)	36.7	33.1	30.6	25.6
Natural gas (MMcf/d)	79.3	55.1	51.2	54.1
NGL (MBbls/d)	1.8	2.3	2.2	1.8
Total (MBOE/d)	51.7	44.5	41.3	36.4
Weighted average prices: (1)				
Oil (Bbl)	$85.56	$92.05	$93.96	$92.29
Natural gas (Mcf)	$4.34	$4.14	$3.79	$2.80
NGL (Bbl)	$39.96	$36.85	$37.95	$41.20
Average NYMEX prices:				
Oil (Bbl)	$93.00	$98.88	$98.01	$94.20
Natural gas (MMBtu)	$4.41	$4.38	$3.70	$2.79
Costs per BOE of production:				
Lease operating expenses	$19.30	$23.10	$20.46	$17.43
Transportation expenses	$2.22	$3.86	$3.23	$2.97
General and administrative expenses	$5.44	$30.43	$8.51	$5.37
Depreciation, depletion and amortization	$16.01	$16.26	$19.35	$17.09
Taxes, other than income taxes	$5.17	$3.19	$3.95	$2.98

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

Revenues and Other

Oil, Natural Gas and NGL Sales

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

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 2014 revenues of approximately $205 million and $39 million, respectively. Lower NGL production volumes resulted in a decrease in 2014 revenues of approximately $5 million.

Oil, natural gas and NGL sales increased by approximately $166 million or 18% to approximately $1.1 billion for the period from January 1, 2013 through December 16, 2013, from approximately $937 million for the year ended December 31, 2012, due to higher oil production volumes and higher oil and natural gas prices, partially offset by lower NGL and natural gas production volumes and lower NGL prices. Higher oil and natural gas prices resulted in an increase in revenues of approximately $30 million and $17 million, respectively. Lower NGL prices resulted in a decrease in revenues of approximately $2 million.

Table of Contents

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

Average daily production volumes increased to approximately 41 MBOE/d for the period from January 1, 2013 through December 16, 2013, from approximately 36 MBOE/d for the year ended December 31, 2012. Higher oil and NGL production volumes resulted in an increase in revenues of approximately $121 million and $5 million, respectively. Lower natural gas production volumes resulted in a decrease in revenues of approximately $5 million. For the period from December 17, 2013, through December 31, 2013, oil, natural gas and NGL sales were approximately $50 million. See tables above for production volumes, commodity prices and sales information.

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

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Average daily production (MBOE/d):				
California	26.0	23.0	20.8	18.0
Uinta Basin	10.9	9.6	8.0	6.1
Permian Basin	7.2	8.0	8.2	6.7
Hugoton Basin	4.0	—	—	—
Piceance Basin	1.9	2.1	2.3	3.0
East Texas	1.7	1.8	2.0	2.6
	51.7	44.5	41.3	36.4

The 2014 increase in average daily production volumes in California and the Uinta Basin operating area primarily reflects development capital spending. The 2014 increase in average daily production volumes in California also reflects the impact of the properties received in the exchange with Exxon Mobil Corporation on November 21, 2014. The 2014 decrease in average daily production volumes in the Permian Basin operating area primarily reflects lower production volumes related to the properties relinquished in the two exchanges with Exxon Mobil Corporation on November 21, 2014, and August 15, 2014, as well as the Permian Basin Assets Sale on November 14, 2014, partially offset by development capital spending. The Company had no Permian Basin properties remaining as of December 31, 2014. The decrease in average daily production volumes in the Piceance Basin and East Texas operating areas primarily reflects the effects of production declines due to reduced development capital spending. Average daily production volumes in the Hugoton Basin operating area reflect the impact of the properties received in the exchange with Exxon Mobil Corporation on August 15, 2014.

Electricity Sales

The following table sets forth selected electricity data:

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Electricity sales (in thousands)	$40,022	$1,444	$33,992	$29,940
Electricity generation expenses (in thousands)	$28,171	$1,257	$22,485	$19,975
Electric power produced (Mwh/d)	2,071	2,217	1,950	2,097
Electric power sold (Mwh/d)	1,882	1,999	1,797	1,918
Average sales price per Mwh	$59.80	$48.15	$53.78	$40.79
	$4.52	$4.58	$3.72	$2.89

Fuel gas cost per MMBtu (including transportation)				
Estimated natural gas volumes consumed to produce electricity (MMBtu/d) [1]	14,948	16,142	14,536	15,415

[1] Estimate is based on the historical allocation of fuel costs to electricity.

Table of Contents

Electricity sales represent sales to utilities and 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.
Electricity sales represent sales to utilities and increased by approximately $4 million or 14% to approximately $34 million for the period from January 1, 2013 through December 16, 2013, from approximately $30 million for the year ended December 31, 2012. In 2012, electricity sales included retroactive payment adjustments for capacity of approximately $1 million from the Company's electricity customers. As a result of a previously disclosed global settlement with various parties that became effective in November 2011, the Company received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and these payments represent the difference in rates over the disputed period. Excluding the retroactive payment adjustments, electricity sales in 2013 would have increased 19% compared to 2012. The increase in electricity sales was primarily due to a 32% increase in the average sales price of electricity, partially offset by a 6% decrease in electric power sold year over year primarily due to an increase in downtime of the Company's cogeneration facilities in 2013 compared to 2012. For the period from December 17, 2013, through December 31, 2013, electricity sales were approximately $1 million.

Gains (Losses) on Oil and Natural Gas Derivatives

Gains on oil and natural gas derivatives were approximately $79 million for the year ended December 31, 2014, compared to losses of 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, representing a variance of approximately $119 million. Gains on oil and natural gas derivatives were primarily due to changes in fair value on unsettled derivative contracts and higher cash settlements during the period. The results for 2014 also include cash settlements of approximately $12 million related to canceled derivatives contracts.
Losses on oil and natural gas derivatives were approximately $35 million for the period from January 1, 2013 through December 16, 2013, compared to gains of approximately $65 million for the year ended December 31, 2012. Losses on oil and natural gas derivatives were primarily due to the changes in fair value of the derivative contracts and decreased cash settlements during the period. For the period from December 17, 2013, through December 31, 2013, losses on oil and natural gas derivatives were approximately $5 million and there were no cash settlements during the period.
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 information 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 gas are recorded as marketing revenues. 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.
Marketing and other revenues were approximately $9 million for both the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012. For the period from December 17, 2013, through December 31, 2013, marketing and other revenues were approximately $399,000.

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

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 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.

Lease operating expenses increased by approximately $64 million or 27% to approximately $296 million for the period from January 1, 2013 through December 16, 2013, from approximately $232 million for the year ended December 31, 2012. Lease operating expenses per BOE also increased to $20.46 per BOE for the period from January 1, 2013 through December 16, 2013, from $17.43 per BOE for the year ended December 31, 2012. The increase was primarily due to an increase of approximately $35 million in steam costs, as the result of a 29% and 28% increase in the price and volume, respectively, of natural gas used in steam generation. Workover and recompletion costs, and contract services costs associated with the Company's Diatomite, Uinta Basin and Permian Basin operating areas also increased during the same time period. For the period from December 17, 2013, through December 31, 2013, lease operating expenses were approximately $15 million.

The following table sets forth steam information:

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Average net volume of steam injected (Bbls/d)	251,726	229,909	201,617	169,605
Fuel gas cost per MMBtu (including transportation)	$4.52	$4.58	$3.72	$2.89
Estimated natural gas volumes consumed to produce steam (MMBtu/d)	90,320	82,275	69,792	54,540

Electricity Generation Expenses

Electricity generation expenses increased $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.

Electricity generation expenses increased $2 million or 13% to approximately $22 million for the period from January 1, 2013 through December 16, 2013, from approximately $20 million for the year ended December 31, 2012, primarily due to a 29% increase in fuel gas cost, partially offset by a 6% decrease in fuel gas volumes purchased. For the period from December 17, 2013, through December 31, 2013, electricity generation expenses were approximately $1 million.

Transportation Expenses

Transportation expenses decreased 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.

Transportation expenses increased approximately $7 million or 18% to approximately $47 million for the period from January 1, 2013 through December 16, 2013, from approximately $40 million for the year ended December 31, 2012, primarily due to the Company shipping oil from its Uinta Basin properties to markets outside of Utah beginning in 2013. For the period from December 17, 2013, through December 31, 2013, transportation expenses were approximately $3 million.

Table of Contents

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 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. For the period from December 17, 2013, through December 31, 2013, marketing expenses were approximately $376,000.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations. 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 Linn Operating, Inc., a subsidiary of LINN Energy. General and administrative expenses per BOE were $5.44 per BOE for the year ended December 31, 2014.

General and administrative expenses increased approximately $51 million or 72% to approximately $123 million for the period from January 1, 2013 through December 16, 2013, from approximately $72 million for the year ended December 31, 2012. The increase was primarily due to approximately $45 million in transaction costs associated with the LINN Energy transaction and a $6 million increase in employee compensation and benefits resulting from general pay increases and increased incentive compensation in 2013. General and administrative expenses per BOE also increased to $8.51 per BOE for the period from January 1, 2013 through December 16, 2013, from $5.37 per BOE for the year ended December 31, 2012. For the period from December 17, 2013, through December 31, 2013, general and administrative expenses were approximately $20 million, which includes approximately $16 million in costs related to employee severance incurred in connection with the LINN Energy transaction.

Exploration Costs

The Company recorded no exploration costs for the year ended December 31, 2014, or 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.

For the year ended December 31, 2012, the Company recorded exploration costs of approximately $21 million primarily related to approximately $12 million of dry hole expense recorded for four appraisal wells in Borden County whose results were inconclusive for commercial quantities of oil and approximately $3 million related to mechanical failure on a well near Lake Canyon, which was abandoned in favor of drilling a nearby replacement well. The Company also recorded approximately $4 million related to plugging and abandonment activities in California for the year ended December 31, 2012.

Depreciation, Depletion and Amortization

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.

Depreciation, depletion and amortization increased by approximately $52 million or 23% to approximately $280 million for the period from January 1, 2013 through December 16, 2013, from approximately $228 million for the year ended December 31, 2013. Higher depletion rates and higher total production volumes were the primary reasons for the increased expense. Depreciation, depletion and amortization per BOE increased to $19.35 per BOE for the period from January 1, 2013 through December 16, 2013, from $17.09 per BOE for the year ended December 31, 2012, primarily due to the Company’s development expenditures during the prior year, partially offset by reserve additions and an increased contribution of development properties with higher drilling and leasehold acquisition costs than the properties in California. For the period from December 17, 2013, through December 31, 2013, depreciation, depletion and amortization was approximately $11 million, or $16.26 per BOE.

Impairment of Long-Lived Assets

During the fourth quarter of 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $253 million associated with proved oil and natural gas properties related to the Uinta Basin operating area. The impairment was due to a steep decline in commodity prices. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas forward price curves decreased approximately 24% and 12%, respectively. The impairment charges were determined using the average five-year NYMEX forward price curves of approximately $64.76 per BBl for oil and $3.66 per MMBtu for natural gas and, thereafter, the prices were held flat at $69.77 per Bbl for oil and $4.12 per MMBtu for natural gas.

Subsequent to December 31, 2014, 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, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Severance taxes	$25,113	$1,248	$17,514	$15,543
Ad valorem taxes	54,819	882	23,995	23,831
California carbon allowances	17,751	—	15,554	—
Other	25	—	—	383
	$97,708	$2,130	$57,063	$39,757

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, which are a function of revenues generated from production, increased primarily due to higher production volumes and higher natural gas and NGL prices partially offset by lower oil prices. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased primarily due to an 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.

Taxes, other than income taxes increased by approximately $17 million or 44% for the period from January 1, 2013 through December 16, 2013, compared to the year ended December 31, 2012. Severance taxes for the period from January 1, 2013 through December 16, 2013, increased primarily due to higher oil and NGL production volumes and higher oil and natural gas prices partially offset by lower natural gas production volumes and lower NGL prices. California carbon allowances for the period from January 1, 2013 through December 16, 2013, increased due to new cap and trade regulations in California that took effect in 2013. For the period from December 17, 2013, through December 31, 2013, taxes, other than income taxes were approximately $2 million.

(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 Exxon Mobil Corporation for properties in California's South Belridge Field; and
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Net loss of approximately $34 million on the noncash exchange of a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc., for properties in the Hugoton Basin.

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

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

Other Income and (Expenses)

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Interest expense, net of amounts capitalized	$(87,948)	$(3,963)	$(96,127)	$(83,136)
Loss on extinguishment of debt	—	—	—	(41,545)
Other, net	(1,043)	(28)	51	109
	$(88,991)	$(3,991)	$(96,076)	$(124,572)

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.

Other income and (expenses) decreased by approximately $28 million for the period from January 1, 2013 through December 16, 2013, compared to the year ended December 31, 2012. Interest expense increased primarily due to higher outstanding debt during the period. For the year ended December 31, 2012, the Company also recorded a loss on extinguishment of debt of approximately $11 million and $31 million in conjunction with the redemption of the 8.25% senior notes due 2016 ("2016 Senior Notes") and the repurchase of $150 million of the 10.25% senior notes due June 2014 ("June 2014 Senior Notes"), respectively (see Note 3). For the period from December 17, 2013, through December 31, 2013, other income and (expenses) were approximately $4 million of expenses.

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

Income Tax Expense (Benefit)

Effective December 16, 2013, 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. 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 therefore, 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 income tax expense of approximately $69,000 for the year ended December 31, 2014, compared to approximately $65 million for the period from January 1, 2013 through December 16, 2013. The decrease 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 recognized income tax expense of approximately $88 million for the year ended December 31, 2012. The Company recorded no income tax expense (benefit) for the period from December 17, 2013, through December 31, 2013.

For predecessor periods, the Company's effective income tax rates for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, were 41% and 34%, respectively. For the period from January 1, 2013 through December 16, 2013, the increase in the effective tax rate was primarily due to nondeductible transaction costs as a result of the LINN Energy transaction. In 2012, the effective income tax rate was reduced by a benefit recorded for research and development tax credits. The Company's estimated annual effective income tax rates in predecessor periods varied from the 35% federal statutory rate primarily due to the effects of state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation, research and development credits and other permanent differences.

Net Income (Loss)

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. 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. Net income decreased by approximately $79 million or 46% to approximately $93 million for the period from January 1, 2013 through December 16, 2013, from approximately $172 million for the year ended December 31, 2012. The decrease was primarily due to higher expenses and lower gains on oil and natural gas derivatives, partially offset by higher production revenues. For the period from December 17, 2013, through December 31, 2013, net loss was approximately $20 million. See discussions above for explanations of variances.

Liquidity and Capital Resources

The Company has utilized funds from debt offerings, borrowings under its Credit Facility and net cash provided by operating activities 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, 2014, the Company’s total capital expenditures were approximately $574 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, 2015, the Company had less than $1 million of available borrowing capacity under its Credit Facility. The next semi-annual redetermination of the borrowing base is scheduled to occur in April 2015. Continued lower commodity prices may result in a decrease in the borrowing base at that time. In February 2015, LINN Energy and Berry entered into a parent support agreement under which LINN Energy agreed, in the event the borrowing base is reduced below the amount of borrowings outstanding, to either make principal repayments or provide additional collateral to the lenders, including through posting restricted cash on Berry’s behalf to address the shortfall, subject to LINN Energy’s credit facility.

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. Following the LINN Energy transaction, 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. The Company believes such resources will be sufficient to conduct the Company’s business and operations.

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 its senior notes limit the amount the Company 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 $275 million at December 31, 2014, 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.

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).

Table of Contents

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

Statements of Cash Flows

The following is a comparative cash flow summary:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Net cash:				
Provided by operating activities	$583,480	$56,678	$442,968	$501,439
Used in investing activities	(516,222)	(17,478)	(586,982)	(758,172)
Provided by (used in) financing activities	(116,713)	(439,272)	599,687	256,747
Net increase (decrease) in cash and cash equivalents	$(49,455)	$(400,072)	$455,673	$14

Operating Activities

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. Cash provided by operating activities for the period from January 1, 2013 through December 16, 2013, was approximately $443 million, compared to approximately $501 million for the year ended December 31, 2012. The decrease was primarily due to lower cash settlements on derivatives and higher expenses, partially offset by higher production related revenues principally due to increased production volumes.

Investing Activities

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

		Successor	Predecessor	
(in thousands)	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Cash flow from investing activities:				
Property acquisitions	$—	$—	$(3,933)	$(78,313)
Development of oil and natural gas properties	(523,889)	(17,478)	(594,579)	(693,866)
Proceeds from sale of properties and equipment and other	7,667	—	11,530	14,007
	$(516,222)	$(17,478)	$(586,982)	$(758,172)

The primary use of cash in investing activities is for the development of the Company's oil and natural gas properties. Capital expenditures for the year ended December 31, 2014, decreased primarily due to lower spending on development activities. The decrease in net cash used in investing activities for the period from January 1, 2013 through December 16, 2013, compared to the year ended December 31, 2012, was primarily due to decreases in property acquisitions and development activities. For the period from December 17, 2013 through December 31, 2013, cash used in investing activities was approximately $17 million and related to development activities.

Financing Activities

Cash used in financing activities of approximately $117 million for the year ended December 31, 2014, was primarily related to cash distributions of approximately $119 million 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.

Cash provided by financing activities for the year ended December 31, 2012, included net proceeds of approximately $590 million from the issuance of $600 million of the Company's September 2022 Senior Notes and net borrowings of approximately $31 million under its Credit Facility, partially offset by the repurchases of $150 million of its June 2014 Senior Notes and all $200 million of its 2016 Senior Notes.

Debt

The Company's Second Amended and Restated Credit Agreement ("Credit Facility") has a borrowing base of $1.4 billion, subject to lender commitments. At January 31, 2015, lender commitments under the facility were $1.2 billion but there was less than $1 million of available borrowing capacity, including outstanding letters of credit. In February 2014, the Company entered into an amendment to the Credit Facility to amend the terms of certain financial and reporting covenants, among other items. In April 2014, the Company entered into an amendment to the Credit Facility to extend the maturity date from May 2016 to April 2019 and to amend the terms of certain financial covenants and definitions, among other items.

The Company is in compliance with all financial and other covenants of its Credit Facility. If an event of default would occur and were continuing, the Company would be unable to make borrowings and its financial condition and liquidity would be adversely affected. For information related to the Credit Facility, see Note 3.

Redemption and Repurchase of Notes

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.

In April 2012, the Company redeemed all $200 million of its 2016 Senior Notes and repurchased $150 million of its June 2014 Senior Notes for an aggregate purchase price of approximately $215 million and $181 million, respectively, including accrued and unpaid interest. These notes were redeemed and repurchased using net proceeds from the issuance of $600 million of the Company's September 2022 Senior Notes.

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.

Table of Contents

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

Commitments and Contractual Obligations

The following is a summary of the Company's commitments and contractual obligations as of December 31, 2014:

Contractual Obligations	Payments Due Total	2015	2016 – 2017	2018 – 2019	2020 and Beyond
	(in thousands)				
Long-term debt obligations:					
Credit Facility	$1,173,175	$—	$—	$1,173,175	$—
Senior notes	899,133	—	—	—	899,133
Interest (1)	560,187	89,768	179,537	156,044	134,838
Operating lease obligations:					
Office, property and equipment leases	13,865	4,384	6,059	2,443	979
Other:					
Asset retirement obligations	121,760	3,101	4,833	5,227	108,599
Firm natural gas transportation contracts (2)	180,399	33,418	66,863	46,499	33,619
Purchase obligations and other (3)	5,294	2,852	2,442	—	—
	$2,953,813	$133,523	$259,734	$1,383,388	$1,177,168

(1) Represents interest on the Credit Facility computed at 2.67% through maturity in April 2019. Interest on the November 2020 Senior Notes and September 2022 Senior Notes, as defined in Note 3, computed at fixed rates of 6.75% and 6.375%, respectively.

(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 three to nine years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

(3) Primarily represents cogeneration facility management services and equipment purchase obligations.

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 GAAP. The preparation of these financial statements requires 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. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of 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 of Notes to Financial Statements.

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, 2014, 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.

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. 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. 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 $6 million, $41,000, $6 million and $18 million for the year ended December 31, 2014, for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, respectively.

Impairment of Proved Properties

Based on the analysis described above, for the year ended December 31, 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $253 million 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 statement of operations. The Company recorded no impairment charges for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, or for the year ended December 31, 2012.

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.

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 year ended 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 and $79,000 for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, respectively. For the year ended December 31, 2012, the Company also recorded dry hole expense and plugging and abandonment activities of approximately $15 million and $4 million, respectively. All of these expenses are included in "exploration costs" on the statements of operations.

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

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and, from time to time, natural gas. 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.

Table of Contents

In prior years, the Company entered into commodity hedging transactions primarily in the form of swap contracts, collars and three-way collars. 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.

Derivative instruments (including certain derivative instruments embedded in other contracts that require bifurcation) are recorded at fair value and included on the balance sheets as assets and/or liabilities. The Company did not designate these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company uses certain pricing models to determine the fair value of its derivative financial instruments. 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. See Note 7 and Note 8 for additional details about the Company's derivative financial instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for sensitivity analysis regarding 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; (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 earnings. 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.

Table of Contents

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how the Company views and manages its ongoing market risk exposures. All of the Company’s market risk sensitive instruments were entered into for purposes other than trading.

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 uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and, from time to time, natural gas. 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. 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. Put options are designed to provide a fixed price floor with the opportunity for upside.

The Company entered into these transactions with respect to a portion of its projected production to provide an economic hedge of the risk related to the future commodity prices received. 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 derivatives contracts, the level of LINN Energy’s acquisition activity and overall risk profile, including leverage and size and scale considerations. As a result, the appropriate percentage of production volumes to be hedged may change over time. As of December 31, 2014, the Company had 1,095 MBbls of oil production volumes hedged for 2015 but no production volumes hedged for years subsequent to 2015.

At December 31, 2014, the fair value of three-way collars was a net asset of approximately $20 million. A 10% increase in the index oil price above the December 31, 2014, price would result in a net asset of approximately $18 million, which represents a decrease in the fair value of approximately $2 million; conversely, a 10% decrease in the index oil price below the December 31, 2014, price would result in a net asset of approximately $21 million, which represents an increase in the fair value of approximately $1 million. At December 31, 2014, the Company had no outstanding natural gas derivative instruments.

At December 31, 2013, the fair value of fixed price swaps, collars and three-way collars was a net liability of approximately $6 million. A 10% increase in the index oil price above the December 31, 2013, price would result in a net liability of approximately $83 million, which represents a decrease in the fair value of approximately $77 million; conversely, a 10% decrease in the index oil price below the December 31, 2013, price would result in a net asset of approximately $67 million, which represents an increase in the fair value of approximately $73 million. At December 31, 2013, the Company had no outstanding natural gas derivative instruments.

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.

The prices of oil, natural gas and NGL have been extremely volatile, and the Company expects this volatility to continue. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for such commodities, market uncertainty and a variety of additional factors that are beyond its control. Actual gains or losses recognized related to the Company's derivative contracts will likely differ from those estimated at December 31, 2014, and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

The Company cannot be assured that its counterparties will be able to perform under its derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, the Company's cash flows could be impacted.

Interest Rate Risk

At December 31, 2014, and December 31, 2013, the Company had long-term debt outstanding under its Credit Facility of approximately $1.2 billion which incurred interest at floating rates (see Note 3). A 1% increase in the London Interbank Offered Rate would result in an estimated $12 million increase in annual interest expense.

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value on a recurring basis (see Note 8). The fair value of these derivative financial instruments includes the impact of assumed credit risk adjustments, which are based on the Company's and counterparties' published credit ratings, public bond yield spreads and credit default swap spreads, as applicable.

At December 31, 2014, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 1.52%. A 1% increase in the average public bond yield spread would result in no significant increase or decrease in net income for the year ended December 31, 2014. At December 31, 2014, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0.20% and 0.27%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $102,000 decrease in net income for the year ended December 31, 2014.

At December 31, 2013, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 0.91%. A 1% increase in the average public bond yield spread would result in an estimated $169,000 increase in net income for the year ended December 31, 2013. At December 31, 2013, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0.17% and 0.38%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $98,000 decrease in net income for the year ended December 31, 2013.

Table of Contents

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

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, 2014, 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 (1992) 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, 2014, based on those criteria.

/s/ Berry Petroleum Company, LLC

Table of Contents

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, 2014 and 2013, and the related statements of operations, comprehensive income (loss), member's equity, and cash flows for the year ended December 31, 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, 2014 and 2013, and the results of its operations and its cash flows for the Successor period, in conformity with U.S. generally accepted accounting principles.

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 5, 2015

Table of Contents

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, comprehensive income (loss), shareholders' equity and cash flows for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, 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, and for the year ended December 31, 2012, 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 audits. We conducted our audits 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 audits provide 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

Table of Contents

BERRY PETROLEUM COMPANY, LLC
BALANCE SHEETS
(in thousands)

	December 31, 2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$1,586	$51,041
Accounts receivable – trade, net	100,359	122,855
Derivative instruments	43,694	5,596
Other current assets	59,259	30,833
Total current assets	204,898	210,325
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	4,872,059	4,813,659
Less accumulated depletion and amortization	(525,007)	(10,394)
	4,347,052	4,803,265
Other property and equipment	115,999	83,126
Less accumulated depreciation	(8,452)	(233)
	107,547	82,893
Derivative instruments	—	2,511
Advance to affiliate	293,627	—
Other noncurrent assets	14,284	8,051
	307,911	10,562
Total noncurrent assets	4,762,510	4,896,720
Total assets	$4,967,408	$5,107,045
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$242,350	$264,271
Derivative instruments	—	20,393
Other accrued liabilities	19,087	28,993
Current portion of long-term debt	—	211,558
Total current liabilities	261,437	525,215
Noncurrent liabilities:		
Credit facility	1,173,175	1,173,175
Senior notes, net	913,777	916,428
Derivative instruments	—	4,649
Other noncurrent liabilities	200,015	192,091
Total noncurrent liabilities	2,286,967	2,286,343
Commitments and contingencies (Note 10)		
Member's equity:		
Additional paid-in capital	2,416,381	2,315,460
Accumulated income (deficit)	2,623	(19,973)

	2,419,004	2,295,487
Total liabilities and member’s equity	$4,967,408	$5,107,045

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

Table of Contents

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

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$1,298,402	$50,324	$1,103,245	$937,261
Electricity sales	40,022	1,444	33,992	29,940
Gains (losses) on oil and natural gas derivatives	78,784	(5,049)	(34,711)	64,620
Marketing revenues	10,889	399	7,827	7,631
Other revenues	3,192	—	949	1,674
	1,431,289	47,118	1,111,302	1,041,126
Expenses:				
Lease operating expenses	364,540	15,410	295,811	232,266
Electricity generation expenses	28,171	1,257	22,485	19,975
Transportation expenses	41,842	2,576	46,774	39,531
Marketing expenses	8,084	376	7,593	6,873
General and administrative expenses	102,787	20,298	122,991	71,564
Exploration costs	—	—	24,048	21,010
Depreciation, depletion and amortization	302,353	10,845	279,757	227,700
Impairment of long-lived assets	253,362	—	—	—
Taxes, other than income taxes	97,708	2,130	57,063	39,757
(Gains) losses on sale of assets and other, net	120,786	10,208	(23)	(1,782)
	1,319,633	63,100	856,499	656,894
Other income and (expenses):				
Interest expense, net of amounts capitalized	(87,948)	(3,963)	(96,127)	(83,136)
Loss on extinguishment of debt	—	—	—	(41,545)
Other, net	(1,043)	(28)	51	109
	(88,991)	(3,991)	(96,076)	(124,572)
Income (loss) before income taxes	22,665	(19,973)	158,727	259,660
Income tax expense	69	—	65,280	88,121
Net income (loss)	$22,596	$(19,973)	$93,447	$171,539

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

BERRY PETROLEUM COMPANY, LLC
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Net income (loss)	$22,596	$(19,973)	$93,447	$171,539
Other comprehensive income, net of income taxes:				
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefit of $3,382 for the year ended December 31, 2012	—	—	—	5,517
Other comprehensive income	—	—	—	5,517
Comprehensive income (loss)	$22,596	$(19,973)	$93,447	$177,056

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

Table of Contents

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

	Class A	Class B	Additional Paid-In Capital	Accumulated Income	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
December 31, 2011	$ 521	$ 18	$ 350,158	$ 495,549	$ (5,517)	$ 840,729
Stock options and restricted stock issued	3	—	3,684	—	—	3,687
Stock-based compensation expense	—	—	9,819	—	—	9,819
Income tax effect of stock option exercises	—	—	1,049	—	—	1,049
Dividends ($0.32 per share)	—	—	—	(17,549)	—	(17,549)
Net income	—	—	—	171,539	—	171,539
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	5,517	5,517
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

STATEMENT 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

(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.

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

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Cash flow from operating activities:				
Net income (loss)	$22,596	$(19,973)	$93,447	$171,539
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	302,353	10,845	279,757	227,700
Impairment of long-lived assets	253,362	—	—	—
Stock-based compensation expense	—	—	12,576	9,819
Loss on extinguishment of debt	—	—	—	6,842
Amortization and write-off of deferred financing fees	(4,913)	(615)	6,685	7,031
Change in book overdraft	—	—	(14,885)	(1,220)
Losses on sale of assets and other, net	111,374	—	14,907	12,028
Deferred income taxes	69	—	76,644	82,881
Derivatives activities:				
Total (gains) losses	(78,784)	5,049	34,711	(64,620)
Cash settlements	6,738	—	182	4,927
Cash settlements on canceled derivatives	12,281	—	—	14,659
Amortization of accumulated other comprehensive loss	—	—	—	8,899
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable – trade, net	16,483	71,434	(97,653)	(6,740)
(Increase) decrease in other assets	(15,949)	10,613	996	(6,203)
Increase (decrease) in accounts payable and accrued expenses	(3,719)	(8,078)	28,187	23,507
Increase (decrease) in other liabilities	(38,411)	(12,597)	7,414	10,390
Net cash provided by operating activities	583,480	56,678	442,968	501,439
Cash flow from investing activities:				
Property acquisitions	—	—	(3,933)	(78,313)
Development of oil and natural gas properties	(523,889)	(17,478)	(594,579)	(693,866)
Proceeds from sale of properties and equipment and other	7,667	—	11,530	14,007
Net cash used in investing activities	(516,222)	(17,478)	(586,982)	(758,172)
Cash flow from financing activities:				
Proceeds from borrowings	—	—	1,225,475	2,067,200
Repayments of debt	(206,124)	—	(615,200)	(1,785,799)
Dividends paid	—	(4,272)	(13,204)	(17,549)
Financing fees and other, net	(11,510)	—	(459)	(11,841)
Proceeds from stock option exercises	—	—	730	3,687

Capital contribution from affiliate	220,000	—	—	—
Distributions to affiliate	(119,079)	(435,000)	—	—
Excess tax benefit from stock-based compensation	—	—	2,345	1,049
Net cash provided by (used in) financing activities	(116,713)	(439,272)	599,687	256,747
Net increase (decrease) in cash and cash equivalents	(49,455)	(400,072)	455,673	14
Cash and cash equivalents:				
Beginning	51,041	451,113	312	298
Ending	$1,586	$51,041	$455,985	$312

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

59

Table of Contents

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), east Texas and Colorado (Piceance Basin). The Company previously had properties in the Permian Basin that were divested during 2014.
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 (the "Delaware Act") and the Limited Liability Company Agreement of Berry Petroleum Company, LLC (the "Agreement"), the member has no liability for the debts, obligations and liabilities of the Company, except as expressly required in the Agreement or the Delaware Act. The Company will remain in existence unless and until dissolved in accordance with the terms of the Agreement.
Basis of Presentation
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 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.
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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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 May 2014, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("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, 2016, and interim periods within those years (early adoption prohibited). The Company is currently evaluating the impact, if any, of the adoption of this ASU on its financial statements and related disclosures.
In April 2014, the FASB issued an ASU that changes the criteria for reporting discontinued operations and enhances disclosures in this area. This ASU is effective for annual and interim periods beginning after December 15, 2014, with early adoption permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. The Company early adopted this ASU on a prospective basis beginning with the third quarter of 2014. The adoption had no effect on the Company's financial statements.
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. Outstanding checks in excess of funds on deposit are included in "accounts payable and accrued expenses."
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, 2014. The balance in the Company's allowance for doubtful accounts related to trade accounts receivable was approximately $473,000 at December 31, 2013.
Inventories
Materials, supplies and commodity inventories are valued at the lower of average cost or market. Inventories also include California carbon allowance instruments.

Table of Contents

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.

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. 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. 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 $6 million, $41,000, $6 million and $18 million for the year ended December 31, 2014, the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, respectively.

Impairment of Proved Properties

Based on the analysis described above, for the year ended December 31, 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $253 million associated with proved oil and natural gas properties related to the Uinta Basin operating area. The impairment was due to a steep decline in commodity prices. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas forward price curves decreased approximately 24% and 12%, respectively. 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 statement of operations. The Company recorded no impairment charges for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, or for the year ended December 31, 2012.

Subsequent to December 31, 2014, 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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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 year ended 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 and $79,000 for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, respectively. For the year ended December 31, 2012, the Company also recorded dry hole expense and plugging and abandonment activities of approximately $15 million and $4 million, respectively. All of these expenses are included in “exploration costs” on the statements of operations.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, buildings, software, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These assets are recorded at cost and are depreciated using the straight-line method based on expected 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. 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 16, 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

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and, from time to time, natural gas. 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.

In prior years, the Company entered into commodity hedging transactions primarily in the form of swap contracts, collars and three-way collars. 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.

Derivative instruments (including certain derivative instruments embedded in other contracts that require bifurcation) are recorded at fair value and included on the balance sheets as assets and/or liabilities. In January 2010, the Company elected to prospectively discontinue hedge accounting, under which changes in derivative fair values were deferred in accumulated other comprehensive loss (“AOCL”). After January 2010, the Company no longer designated these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company uses certain pricing models to determine the fair value of its derivative financial instruments. 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. 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, 2014, and December 31, 2013. 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, 2014, and December 31, 2013, net deferred financing fees of approximately $12 million and $5 million, respectively, are included in “other noncurrent assets” on the balance sheets. 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 year ended December 31, 2014, the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, amortization expense of approximately $3 million, $83,000, $5 million and $5 million, respectively, is included in “interest expense, net of amounts capitalized” on the statements of operations.

Other Current Assets

The components of other current assets are as follows:

	December 31, 2014	2013
	(in thousands)	
Prepaid expenses	$1,210	$3,652
California carbon allowance inventories	38,409	15,895
Oil inventories	4,034	7,436
Materials inventories	1,747	3,036
Receivables from exchanges of properties and divestitures, and other	13,859	814
Other current assets	$59,259	$30,833

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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

	December 31, 2014	2013
	(in thousands)	
Accrued interest	$15,803	$18,926
Accrued compensation	—	6,749
Asset retirement obligations	3,101	3,318
Other	183	—
Other accrued liabilities	$19,087	$28,993

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.
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, 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 year ended December 31, 2012, the Company's two largest customers represented approximately 43% and 13% of the Company's oil, natural gas and NGL sales. For the years ended December 31, 2014, December 31, 2013, and December 31, 2012, 100% of electricity sales were attributable to two customers.
At December 31, 2014, trade accounts receivable from two customers represented approximately 36% and 10% of the Company's receivables. At December 31, 2013, trade accounts receivable from one customer represented approximately 48% of the Company's receivables.
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, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Cash payments for interest, net of amounts capitalized	$95,915	$—	$87,495	$64,602
Cash payments for income taxes	$—	$—	$622	$4,227
Noncash investing activities:				
Accrued capital expenditures	$59,884	$77,001	$70,866	$98,020

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 Exxon Mobil Corporation and its affiliates in exchange for properties in California's South Belridge Field and the Hugoton Basin, respectively.

Note 2 – Exchanges of Properties, Divestitures and LINN Energy Transaction

Exchanges of Properties

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 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, equal to the difference between the carrying value and the fair value of the assets exchanged, which is included in "(gains) losses on sale of assets and other, net" on the statement of operations.

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., 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, equal to the difference between the carrying value and the fair value of the assets exchanged, which is included in "(gains) losses on sale of assets and other, net" on the statement of operations.

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 fair value measurements of assets acquired and liabilities assumed are 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.

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.

Acquisitions – 2012

On September 12, 2012, the Company completed the acquisition of approximately 14,000 net acres contiguous to the Company's Brundage Canyon asset in the Uinta Basin for approximately $40 million. The acquisition was financed using the Company's Credit Facility.

On April 13, 2012, the Company completed the acquisition of approximately 2,000 net acres and one well in the Wolfberry trend in the Permian Basin for approximately $15 million. The acquisition was financed using the Company's Credit Facility.

Divestitures

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 (the "Permian Basin Assets Sale"). Cash proceeds from the sale of these properties were approximately $351 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 must 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.

On January 31, 2012, the Company completed the sale of certain properties in Elko, Eureka and Nye counties in Nevada (the "Nevada Assets") for total cash consideration of approximately $16 million, and recognized a net gain of approximately $2 million which is included in "(gains) losses on sale of assets and other, net" on the statement of operations for the year ended December 31, 2012.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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

	December 31, 2014	2013
	(in thousands, except percentages)	
Credit facility [1]	$1,173,175	$1,173,175
10.25% senior notes due June 2014	—	205,257
6.75% senior notes due November 2020	299,970	300,000
6.375% senior notes due September 2022	599,163	600,000
Net unamortized premiums	14,644	22,729
Total debt, net	2,086,952	2,301,161
Less current maturities	—	(211,558)
Total long-term debt, net	$2,086,952	$2,089,603

[1] Variable interest rate of 2.67% at both December 31, 2014, and December 31, 2013.

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, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Credit facility	$1,173,175	$1,173,175	$1,173,175	$1,173,175
Senior notes, net	913,777	699,462	1,127,986	1,128,527
Total debt, net	$2,086,952	$1,872,637	$2,301,161	$2,301,702

Credit Facility
The Company's Second Amended and Restated Credit Agreement ("Credit Facility") has a borrowing base of $1.4 billion, subject to lender commitments. At December 31, 2014, lender commitments under the facility were $1.2 billion but there was less than $1 million of available borrowing capacity, including outstanding letters of credit. In February 2014, the Company entered into an amendment to the Credit Facility to amend the terms of certain financial and reporting covenants, among other items. In April 2014, the Company entered into an amendment to the Credit Facility to extend the maturity date from May 2016 to April 2019 and to amend the terms of certain financial covenants and definitions, among other items.

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. Significant declines in commodity prices may result in a decrease in the borrowing base. Berry's obligations under the Credit Facility are secured by mortgages on its oil and natural gas properties and other personal property. Berry is required to maintain mortgages on properties representing at least 80% of the present value of its oil and natural gas proved reserves. The Company is in compliance with all financial and other covenants of the Credit Facility.

At the Company's election, interest on borrowings under the Credit Facility is determined by reference to either the LIBOR plus an applicable margin between 1.5% and 2.5% 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 0.5% and 1.5% 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 LIBOR. The Company is required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum between 0.375% and 0.5% (depending on the then-current level of utilization under the Credit Facility) on the average daily unused amount of the maximum commitment amount of the lenders.

The next semi-annual redetermination of the borrowing base is scheduled to occur in April 2015. Continued lower commodity prices may result in a decrease in the borrowing base at that time. In February 2015, LINN Energy and Berry entered into a parent support agreement under which LINN Energy agreed, in the event the borrowing base is reduced below the amount of borrowings outstanding, to either make principal repayments or provide additional collateral to the lenders, including through posting restricted cash on Berry's behalf to address the shortfall, subject to LINN Energy's credit facility.

Senior Notes Due November 2020

The Company has $300 million in aggregate principal amount of 6.75% senior notes due November 2020 (the "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 beginning on or after November 1, 2015 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.

Senior Notes Due September 2022

The Company has $599 million in aggregate principal amount of 6.375% senior notes due September 2022 (the "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.

Prior to March 15, 2015, the Company may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the September 2022 Senior Notes with the net cash proceeds of certain equity offerings and if certain conditions are met as described in the indenture governing the September 2022 Senior Notes, at a redemption price of 106.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. At any time prior to March 15, 2017, the Company may also 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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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

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 10.25% senior notes due June 2014 (the "June 2014 Senior Notes"), November 2020 Senior Notes and September 2022 Senior Notes, respectively.

In April 2012, the Company redeemed all $200 million aggregate principal amount of its 8.25% senior notes due 2016 (the "2016 Senior Notes") and repurchased $150 million aggregate principal amount of its June 2014 Senior Notes for an aggregate purchase price of approximately $215 million and $181 million, respectively, including accrued and unpaid interest. The related loss of approximately $42 million recorded in loss on extinguishment of debt consists of approximately $35 million in premiums paid over par and approximately $7 million in write-offs of debt issuance costs. These notes were redeemed and repurchased using net proceeds from the issuance of the Company's September 2022 Senior Notes.

Payment of Senior Notes Due June 2014

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).

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. The Company is 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, the indentures governing its 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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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. 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, 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" on the statements of operations.

Income tax expense consisted of the following:

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Current taxes:				
Federal	$—	$—	$(225)	$286
State	—	—	(11,043)	4,954
Deferred taxes:				
Federal	—	—	56,620	80,083
State	69	—	19,928	2,798
	$69	$—	$65,280	$88,121

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

	Successor		Predecessor	
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
Federal statutory rate	35 %	35 %	35 %	35 %
State, net of federal tax benefit	—	—	3	3
Income excluded from nontaxable entities	(35)	(35)	—	—
Deferred state rate impact	—	—	—	(1)
Research and development credits	—	—	—	(3)
Net impact to uncertain income tax positions	—	—	(2)	—
Transaction costs	—	—	4	—
Other	—	—	1	—
Effective rate	— %	— %	41 %	34 %

The effective tax rate was zero for the year ended December 31, 2014, and for the successor 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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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

	Successor December 31, 2014	Predecessor December 31, 2013
(in thousands)		
Deferred tax assets:		
Net operating loss carryforwards	$—	$—
Other	—	—
	—	—
Deferred tax liabilities:		
Property and equipment principally due to differences in depreciation	—	—
Other	69	—
	69	—
Net deferred tax liabilities	$69	$—

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. Therefore, the Company’s net deferred income tax liabilities of approximately $256 million at December 31, 2012, decreased to zero at December 31, 2013. 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.

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, 2014, the Company is in a net deferred tax liability position and has no deferred tax assets.

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, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Unrecognized tax benefits at beginning of period	$—	$—	$22,553	$2,864
Increases for positions taken in current year	—	—	50	21
Increases (decreases) for positions taken in a prior year	—	—	(635)	20,458
Decreases for settlements with taxing authorities	—	—	—	—
Decreases for lapses in the applicable statute of limitations	—	—	(1,862)	(790)
Unrecognized tax benefits at end of period	$—	$—	$20,106	$22,553

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, 2014, and December 31, 2013.

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 2011 – 2013 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. The Company had accrued approximately $19,000 and $426,000 of interest related to its uncertain income tax positions as of December 16, 2013, and December 31, 2012, respectively.

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 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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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, (the (“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’ 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 statements of operations for grants under the Equity Incentive Plans was approximately $12 million and $9 million for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, respectively.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Stock Options
The following table summarizes stock option activity under the predecessor's Equity Incentive Plans for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands) (1)	Weighted Average Remaining Contractual Term (Years)
Outstanding at December 31, 2011	1,520,689	30.32	17,798	
Granted	82,262	53.02		
Exercised	(215,359)	17.12	7,194	
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 fair value of each option granted was estimated using the Black-Scholes option pricing model. Expected volatility was calculated based on the historical volatility of the Company's Common Stock, and the risk-free interest rate was based on U.S. treasury yield curve rates with maturities consistent with the expected life of each stock option. The key assumptions used in computing the weighted average fair market value of stock options granted were as follows:

	2012
Expected volatility	50.00%
Risk-free rate	0.95%
Dividend yield	0.57%
Expected term (in years)	5.2

The following table summarizes 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

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Restricted Stock Units
The following table summarizes RSU activity under the predecessor's Equity Incentive Plans for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Vest Date Fair Value (in thousands)
Outstanding at December 31, 2011	915,022	$23.88	
Granted	164,112	50.60	
Issued	(79,068)	33.10	$3,401
Canceled/expired	(18,189)	41.50	
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 summarizes performance share award activity under the predecessor's Equity Incentive Plans for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012:

	Performance Share Awards	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at December 31, 2011	162,849	$39.00	
Granted	59,738	63.69	
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.

BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

For the portion of the performance share awards subject to market-based vesting criteria, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's Common Stock, and the risk-free interest rate is based on U.S. treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based portion of the performance share awards were as follows:

	2012
Number of simulations	100,000
Expected volatility	50%
Risk-free rate	0.42%

The total grant date fair value of the market-based portion of the performance share awards issued during the year ended December 31, 2012, as determined by the Monte Carlo valuation model, was approximately $1 million and was being recognized ratably over the respective three-year vesting period. Compensation expense for the market-based portion of the performance share awards was not 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 for the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, were 10,758 and 12,797, respectively.

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 for the period from January 1, 2013 through December 16, 2013. The Company's contributions to the 401(k) Plan, net of forfeitures, were approximately $2 million for both the period from January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012.

At December 31, 2014, and December 31, 2013, 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

In prior years, the Company hedged a significant portion of its forecasted oil production to reduce exposure to commodity price fluctuations and provide long-term cash flow predictability to manage its business. The Company also, from time to time, entered into derivative contracts for a portion of its natural gas consumption. The direct NGL hedging market has been constrained in terms of price, volume, duration and number of counterparties, which limited the Company's ability to effectively hedge its NGL production. As a result, the Company has not directly hedged its

NGL production.

The Company 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 entered into these transactions with respect to a portion of its projected production to provide an economic hedge of the risk related to the future commodity prices received. 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 summarizes derivative positions for the period indicated as of December 31, 2014:

	2015
Oil positions:	
Three-way collars (NYMEX WTI):	
Hedged volume (MBbls)	1,095
Short put ($/Bbl)	$70.00
Long put ($/Bbl)	$90.00
Short call ($/Bbl)	$101.62

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. Currently, the Company has no outstanding ICE Brent – NYMEX WTI basis swaps.

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, 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 light 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 summarizes the fair value of derivatives outstanding on a gross basis:

	December 31, 2014	2013
	(in thousands)	
Assets:		
Commodity derivatives	$60,843	$28,291
Liabilities:		
Commodity derivatives	$17,149	$45,226

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 $61 million at December 31, 2014. 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.

Gains (Losses) on Derivatives

Gains and losses on oil and natural gas derivatives were net gains of approximately $79 million for the year ended December 31, 2014, and net losses of 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. Gains and losses on oil and natural gas derivatives were net gains of approximately $65 million for the year ended December 31, 2012. For the year ended December 31, 2014, period from January 1, 2013 through December 16, 2013, and year ended December 31, 2012, the Company received cash settlements of approximately $19 million, $182,000 and $20 million, respectively.

Discontinuance of Hedge Accounting

In 2010, the Company elected to de-designate all of its derivatives contracts that had been previously designated as cash flow hedges. As a result of discontinuing hedge accounting, the fair values of the Company's open derivative instruments designated as cash flow hedges, less any ineffectiveness recognized, were frozen in AOCL and reclassified into earnings as the original hedge transactions settled. For the year ended December 31, 2012, a loss of approximately $11 million and a gain of approximately $2 million of noncash amortization of AOCL related to discontinuing hedge accounting were reclassified from AOCL to oil, natural gas and NGL sales and interest expense, respectively. As of December 31, 2012, the entire balance of AOCL had been reclassified into earnings.

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).

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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.

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

	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)	$—

	December 31, 2013		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$28,291	$(20,184)	$8,107
Liabilities:			
Commodity derivatives	$45,226	$(20,184)	$25,042

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

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

Note 9 – Other Property and Equipment
Other property and equipment consists of the following:

	December 31, 2014	2013
	(in thousands)	
Plant and pipeline, drilling and other equipment	$101,655	$74,155
Buildings and leasehold improvements	10,585	6,515
Vehicles	3,759	2,456
	115,999	83,126
Less accumulated depreciation	(8,452)	(233)
	$107,547	$82,893

Note 10 – 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, $302,000, $5 million and $3 million for the year ended December 31, 2014, the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, respectively.
The table below presents the Company’s future minimum payments under noncancelable operating leases and other commitments as of December 31, 2014:

	Total	2015	2016	2017	2018	2019	Thereafter
(in thousands)							
Operating leases [(1)]	$13,865	$4,384	$3,801	$2,258	$1,269	$1,174	$979
Other commitments [(2)]	5,294	2,852	2,442	—	—	—	—
Firm natural gas transportation contracts [(3)]	180,399	33,418	33,446	33,417	23,972	22,527	33,619
Total	$199,558	$40,654	$39,689	$35,675	$25,241	$23,701	$34,598

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

(2) Other commitments relate primarily to cogeneration facility management services and equipment purchase obligations.

(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 one to nine years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

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 fair value of the property associated with this transaction was recorded in the amount of approximately $13 million and is being depreciated over the remaining useful life of the asset. Under the agreements, portions of the payments are recorded as gathering expense and interest expense with the balance recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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 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 entered into in April 2014, if by September 30, 2015, the Company does not expend $9 million on the construction of either the extension of the road or a new 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 2014 amendment, this deadline is subject to further extension to no later than December 31, 2015. 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 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
Department of the Interior Notice of Proposed Debarment
In June 2012, the Company received a Notice of Proposed Debarment issued by the United States Department of the Interior ("DOI"). Pursuant to the notice, the DOI's Office of the Inspector General proposed to debar the Company from participation in certain federal contracts and assistance activities, including oil and natural gas leases, for a period of three years. The basis for the proposed debarment relates to the Company's purported noncompliance with Bureau of Land Management ("BLM") regulations relating to the operation of certain equipment and the submission of related site facility diagrams in its Uinta operations. In 2011, the Company entered into a settlement agreement with the BLM and paid a $2 million civil penalty relating to the matter. The Company contested the proposed debarment and believes the matter is without merit; nevertheless, in June 2013, the Company entered into an agreement with the DOI to resolve the matter administratively through an independent compliance review. The independent compliance review has concluded and the final compliance review reports have been submitted to the DOI. The Company has been informed that the DOI intends to make follow-up inquiries to the Company in the near future, but has not received any further communications to date.
Royalty Class Action
The Company is a defendant in a certain statewide royalty class action case. The parties entered into a settlement agreement to settle past claims for approximately $2.4 million, which the Court approved on October 29, 2014. On December 17, 2014, the Company made a one-time lump sum payment of $2.4 million for damages related to production through April 30, 2014. On December 29, 2014, the Court issued an Order dismissing the matter with prejudice. Per the parties' settlement agreement, the Company has agreed to a new methodology for calculating royalty payments beginning May 1, 2014.
Other
The Company is involved in various other 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,

Table of Contents

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 year ended December 31, 2014, the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, 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 11 – 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 presents a reconciliation of the Company’s asset retirement obligations:

	Successor		Predecessor
	Year Ended December 31, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013
(in thousands)			
Asset retirement obligations at beginning of period [1]	$94,830	$94,612	$86,746
Liabilities added from drilling	5,124	—	10,097
Settlements	(5,260)	—	(3,882)
Liabilities added from acquisitions	25,223	—	—
Liabilities associated with assets divested	(5,460)	—	(40)
Current year accretion expense	5,670	218	7,136
Revision of estimates	1,633	—	5,900
Asset retirement obligations at end of period	$121,760	$94,830	$105,957

(1) As a result of the application of pushdown accounting, the Company remeasured its asset retirement obligations on the LINN Energy transaction date.

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.

Table of Contents
BERRY PETROLEUM COMPANY
NOTES TO FINANCIAL STATEMENTS - Continued

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. For the year ended December 31, 2014, and for the period from December 17, 2013 through December 31, 2013, the Company incurred management fee expenses of approximately $86 million and $20 million, respectively, for services provided by LOI.

In May 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 June 2014 Senior Notes plus accrued interest. For the year ended December 31, 2014, the Company made cash distributions of approximately $119 million to LINN Energy. In addition, the net cash proceeds from the Permian Basin Assets Sale of approximately $351 million were advanced by the Company to a subsidiary of LINN Energy. These proceeds must 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. For the year ended December 31, 2014, LINN Energy incurred approximately $59 million in capital expenditures in respect of Berry's operations, which resulted in a reduction of the advance.

On December 19, 2013, the Company made a distribution of $435 million to LINN Energy. In connection with the LINN Energy transaction, LOI transferred a derivative liability of approximately $31 million to the Company. The Company also had affiliated accounts payable due to LOI of approximately $13 million and $17 million at December 31, 2014, and December 31, 2013, respectively, included in "accounts payable and accrued expenses" on the balance sheets.

In February 2015, LINN Energy and Berry entered into a parent support agreement under which LINN Energy agreed, in the event the borrowing base of Berry's Credit Facility is reduced below the amount of borrowings outstanding, to either make principal repayments or provide additional collateral to the lenders, including through posting restricted cash on Berry's behalf to address the shortfall, subject to LINN Energy's credit facility.

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 year ended December 31, 2014, the Company paid approximately $176,000 to Superior or its subsidiaries for services rendered to the Company. The transactions associated with these payments were consummated on terms equivalent to those that prevail in arm's-length transactions.

Table of Contents

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, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Property acquisition costs:				
Proved	$478,311	$—	$3,457	$70,700
Unproved	—	—	463	10,686
Exploration costs	148	—	868	16,405
Development costs	555,629	22,266	577,568	696,095
Asset retirement costs	6,064	—	15,998	18,248
Total costs incurred [1]	$1,040,152	$22,266	$598,354	$812,134

(1) The total above does not reflect approximately $6 million, $41,000, $6 million and $18 million of capitalized interest incurred for the year ended December 31, 2014, for the periods from December 17, 2013 through December 31, 2013, and January 1, 2013 through December 16, 2013, and for the year ended December 31, 2012, 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, 2014	2013
	(in thousands)	
Oil and natural gas:		
Proved properties	$4,025,595	$3,397,785
Unproved properties	846,464	1,415,874
	4,872,059	4,813,659
Less accumulated depletion and amortization	(525,007)	(10,394)
	$4,347,052	$4,803,265

Table of Contents

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, 2014	December 17, 2013 through December 31, 2013	January 1, 2013 through December 16, 2013	Year Ended December 31, 2012
(in thousands)				
Revenues and other:				
Oil, natural gas and natural gas liquid sales	$1,298,402	$50,324	$1,103,245	$937,261
Gains (losses) on oil and natural gas derivatives	78,784	(5,049)	(34,711)	64,620
	1,377,186	45,275	1,068,534	1,001,881
Production costs:				
Lease operating expenses	364,540	15,410	295,811	232,266
Transportation expenses	41,842	2,576	46,774	39,531
Severance taxes, ad valorem taxes and California carbon allowances	97,683	2,130	57,063	39,374
	504,065	20,116	399,648	311,171
Other costs:				
Exploration costs	—	—	24,048	21,010
Depletion and amortization	294,107	10,612	275,927	224,836
Impairment of long-lived assets	253,362	—	—	—
(Gains) losses on sale of assets and other, net	112,303	10,208	(23)	(1,782)
	659,772	20,820	299,952	244,064
Income tax expense	69	—	65,280	88,121
Results of operations	$213,280	$4,339	$303,654	$358,525

There is no federal tax provision included in the results above for the year ended December 31, 2014, and 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 year ended 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.

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 SEC regulations, reserves at December 31, 2014, December 31, 2013, and December 31, 2012, 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, 2014		
	Oil MBbls	Natural Gas MMcf	Total MBOE
Total proved reserves:			
Beginning of year	187,362	280,117	234,048
Revisions of previous estimates	(10,647)	42,514	(3,561)
Extensions, discoveries and other additions	20,435	35,552	26,360
Purchases of minerals in place	22,533	408,857	90,676
Sales of minerals in place	(41,216)	(51,065)	(49,727)
Production	(14,065)	(28,938)	(18,888)
End of year	164,402	687,037	278,908
Proved developed reserves	119,039	552,184	211,069
Proved undeveloped reserves	45,363	134,853	67,839
Total proved reserves	164,402	687,037	278,908

	Successor December 17, 2013 through December 31, 2013			Predecessor January 1, 2013 through December 16, 2013		
	Oil MBbls	Natural Gas MMcf	Total MBOE	Oil MBbls	Natural Gas MMcf	Total MBOE
Total proved reserves:						
Beginning of period	187,892	280,943	234,715	204,208	425,519	275,129
Revisions of previous estimates	—	—	—	(13,536)	(153,330)	(39,092)
Extensions, discoveries and other additions	—	—	—	10,955	29,756	15,913
Sales of minerals in place	—	—	—	(2,263)	(3,071)	(2,775)
Production	(530)	(826)	(667)	(11,472)	(17,931)	(14,460)
End of period	187,362	280,117	234,048	187,892	280,943	234,715
Proved developed reserves	121,694	202,798	155,494	122,224	203,624	156,161
Proved undeveloped reserves	65,668	77,319	78,554	65,668	77,319	78,554
Total proved reserves	187,362	280,117	234,048	187,892	280,943	234,715

Table of Contents

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

	Predecessor		
	Year Ended December 31, 2012		
	Oil MBbls	Natural Gas MMcf	Total MBOE
Total proved reserves:			
Beginning of year	185,880	534,279	274,926
Revisions of previous estimates	12,145	(205,845)	(22,162)
Extensions, discoveries and other additions	8,459	100,129	25,148
Purchases of minerals in place	8,304	16,740	11,094
Sales of minerals in place	(556)	—	(556)
Production	(10,024)	(19,784)	(13,321)
End of year	204,208	425,519	275,129
Proved developed reserves	118,937	187,668	150,216
Proved undeveloped reserves	85,271	237,851	124,913
Total proved reserves	204,208	425,519	275,129

The tables above include changes in estimated quantities of natural gas reserves shown in BOE equivalents at a rate of six Mcf per one barrel.

Since the reserves were estimated in accordance with SEC regulations, 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, the Company had positive price revisions for the year ended December 31, 2014, even though there was a steep decline in commodity prices during the fourth quarter of 2014. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas prices decreased approximately 42% and 30%, respectively, to $53.27 per Bbl for oil and $2.89 per MMBtu for natural gas at December 31, 2014. 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 negative revisions due to asset performance and the SEC five-year development limitation on PUDs partially offset by positive revisions primarily due to higher natural gas prices. During the year ended December 31, 2014, properties acquired in the exchanges with Exxon Mobil Corporation increased proved reserves by approximately 90,676 MBOE and the Permian Basin Assets Sale and properties relinquished in the exchanges with Exxon Mobil Corporation 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.

Proved reserves increased by approximately 203 MBOE to approximately 275,129 MBOE for the year ended December 31, 2012, from 274,926 MBOE for the year ended December 31, 2011. The year ended December 31, 2012, includes 22,162 MBOE of negative revisions of previous estimates, primarily in the Piceance Basin and East

Texas due to the SEC five-year development limitation on PUDs and pricing, offset by positive revisions due to development drilling in Diatomite, McKittrick,

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

and the Permian Basin. During the year ended December 31, 2012, the Company acquired reserves of approximately 11,094 MBOE primarily in Utah and the Permian Basin, and the sale of its Nevada Assets (see Note 2) decreased proved reserves by approximately 556 MBOE. In addition, extensions and discoveries, primarily from 467 productive wells drilled during the year, contributed approximately 25,148 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 at December 31, 2014, and December 31, 2013, 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. Prior to the LINN Energy transaction, the Company was a Subchapter C-corporation subject to federal and state income taxes. Future income tax expenses at December 31, 2012, were computed by applying the appropriate year-end statutory income tax rates to the estimated future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax bases of the properties involved. The future income tax expenses gave effect to income tax deductions, credits and allowances relating to the proved oil and natural gas reserves.

	Successor December 31, 2014	December 31, 2013	Predecessor December 31, 2012
(in thousands)			
Future estimated revenues	$16,844,678	$17,863,984	$19,738,729
Future estimated production costs	(7,742,035)	(6,654,536)	(5,884,891)
Future estimated development costs	(1,132,807)	(1,854,849)	(2,164,780)
Future estimated income tax expense	—	—	(3,344,024)
Future net cash flows	7,969,836	9,354,599	8,345,034
10% annual discount for estimated timing of cash flows	(3,639,459)	(4,719,267)	(4,511,619)
Standardized measure of discounted future net cash flows	$4,330,377	$4,635,332	$3,833,415
Representative NYMEX prices: [1]			
Oil (Bbl)	$95.27	$96.89	$90.66
Natural gas (MMBtu)	4.35	3.67	2.88

(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.

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

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

(in thousands)	Successor December 31, 2014
Standardized measure—beginning of year	$4,635,332
Sales and transfers of oil, natural gas and NGL produced during the period	(794,337)
Changes in estimated future development costs	68,290
Net change in sales and transfer prices and production costs related to future production	(1,020,605)
Extensions, discoveries and improved recovery	674,392
Purchases of minerals in place	548,256
Sales of minerals in place	(486,903)
Previously estimated development costs incurred during the period	269,473
Net change due to revisions in quantity estimates	(66,696)
Accretion of discount	463,533
Changes in production rates and other	39,642
Net decrease	(304,955)
Standardized measure—end of year	$4,330,377

(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

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

(in thousands)	Predecessor December 31, 2012
Standardized measure—beginning of year	$4,035,279
Sales and transfers of oil, natural gas and NGL produced during the period	(625,707)
Changes in estimated future development costs	(331,498)
Net change in sales and transfer prices and production costs related to future production	(786,022)
Extensions, discoveries and improved recovery	124,466
Purchases of minerals in place	114,094
Sales of minerals in place	(15,283)
Previously estimated development costs incurred during the period	497,036
Net change due to revisions in quantity estimates	743
Accretion of discount	570,505
Income taxes	323,128
Changes in production rates and other	(73,326)
Net decrease	(201,864)
Standardized measure—end of year	$3,833,415

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.

Table of Contents

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)				
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, net	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)

	Predecessor Periods Ended March 31	June 30	September 30	October 1, 2013 through December 16, 2013	Successor Period Ended December 17, 2013 through December 31, 2013
(in thousands)					
2013:					
Oil, natural gas and natural gas liquids sales	$266,772	$274,715	$306,183	$255,575	$50,324
Electricity sales	7,589	9,513	10,046	6,844	1,444
Gains (losses) on oil and natural gas derivatives	(737)	35,622	(45,293)	(24,303)	(5,049)
Total revenues and other, net	276,123	322,338	273,014	239,827	47,118
Total expenses [(1)]	198,239	201,331	202,647	254,305	52,892
(Gains) losses on sale of assets and other, net	(23)	—	—	—	10,208
Net income (loss)	32,434	61,364	28,178	(28,529)	(19,973)

(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.

Table of Contents

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, 2014.

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 2014 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None

Table of Contents

Part III

Item 10. Directors and 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 fiscal year 2013, and for the fiscal year 2014.

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 year ended December 31, 2014, and for the period from December 17, 2013 through December 31, 2013, were $775,000 and $450,000, respectively. Berry Petroleum Company, LLC incurred no audit fees to KPMG LLP prior to December 17, 2013.

Audit-Related Fees

KPMG LLP also received fees of $25,000 for services in connection with procedures performed for other SEC filings during the fiscal year ended December 31, 2014. Berry Petroleum Company, LLC incurred no fees during the fiscal year ended December 31, 2013, for audit-related services provided by KPMG LLP.

Tax Fees

Berry Petroleum Company, LLC incurred no fees during the fiscal years ended December 31, 2014, and December 31, 2013, for tax-related services provided by KPMG LLP.

All Other Fees

Berry Petroleum Company, LLC incurred no other fees during the fiscal years ended December 31, 2014, and December 31, 2013, for any other services provided by KPMG LLP.

Table of Contents

Item 14. Principal Accounting Fees and Services - Continued

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

Audit Fees

The fees for professional services rendered by PricewaterhouseCoopers LLP for the audit of Berry Petroleum Company, LLC's financial statements for the period from January 1, 2013 through December 16, 2013, were $1,246,000.

Audit-Related Fees

PricewaterhouseCoopers LLP also received fees of $170,000 and $150,000 for services in connection with procedures performed for other SEC filings during the fiscal years ended December 31, 2014, and December 31, 2013, respectively.

Tax Fees

Berry Petroleum Company, LLC incurred no fees during the fiscal year ended December 31, 2014, for tax services provided by PricewaterhouseCoopers LLP. PricewaterhouseCoopers LLP received fees of approximately $282,000 for tax services provided during the fiscal year ended December 31, 2013.

All Other Fees

Berry Petroleum Company, LLC incurred no other fees during the fiscal years ended December 31, 2014, and December 31, 2013, for any other services provided by PricewaterhouseCoopers LLP.

Table of Contents

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.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BERRY PETROLEUM COMPANY, LLC

Date: March 5, 2015	By:	/s/ Mark E. Ellis Mark E. Ellis President and Chief Executive Officer
Date: March 5, 2015	By:	/s/ David B. Rottino David B. Rottino Executive Vice President, Business Development and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual 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 5, 2015
/s/ Kolja Rockov Kolja Rockov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 5, 2015
/s/ David B. Rottino David B. Rottino	Executive Vice President, Business Development and Chief Accounting Officer (Principal Accounting Officer)	March 5, 2015

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

/s/ David B. Rottino David B. Rottino	Executive Vice President, Business Development and Chief Accounting Officer	March 5, 2015

Table of Contents

Index to Exhibits

Exhibit Number		Description
2.1	—	Exchange Agreement by and among Linn Energy Holdings, LLC, Berry Petroleum Company, LLC, XTO Energy Inc., ExxonMobil Oil Corporation, Mobil E&P U.S. Development Corporation and Exxon Mobil Corporation, dated as of May 20, 2014 (incorporated herein by reference to Exhibit 2.5 to Amendment No. 2 to Linn Energy, LLC's Registration Statement on Form S-4 (File No. 333-187458) filed on May 28, 2014)
2.2	—	First Amendment to Exchange Agreement by and among Linn Energy Holdings, LLC, Berry Petroleum Company, LLC, XTO Energy Inc., ExxonMobil Oil Corporation, Mobil E&P U.S. Development Corporation and Exxon Mobil Corporation, dated as of May 22, 2014 (incorporated herein by reference to Exhibit 2.6 to Amendment No. 2 to Linn Energy, LLC's Registration Statement on Form S-4 (File No. 333-187458) filed on May 28, 2014)
2.3	—	Exchange Agreement by and among Linn Energy Holdings, LLC, Berry Petroleum Company, LLC and Exxon Mobil Corporation, dated as of September 18, 2014 (incorporated herein by reference to Exhibit 2.1 to Linn Energy, LLC's Quarterly Report on Form 10-Q filed on November 4, 2014)
2.4	—	Purchase and Sale Agreement by and among Berry Petroleum Company, LLC d/b/a in the State of Texas as Berry Oil Company and Linn Operating, Inc., as Seller, and EIGF TE GP Resource Holdings L.P., FDL Capital, LLC, and KNR Resource Holdings I L.P., as Buyers, executed on October 1, 2014 (incorporated herein by reference to Exhibit 2.2 to the Company's Quarterly Report on Form 10-Q filed on November 12, 2014)
3.1	—	Certificate of Formation (incorporated 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 dated December 16, 2013 (incorporated 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)

98

Table of Contents

Index to Exhibits - Continued

Exhibit Number		Description
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)
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)
		The Registrant is party to other debt instruments not filed herewith under which the total amount of securities authorized does not exceed 10% of the total assets of Berry. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, Berry agrees to furnish a copy of such instruments to the SEC upon request.
10.11**	—	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)
10.12*	—	Parent Support Agreement dated February 20, 2015 between the Registrant and Linn Energy, LLC
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*	—	2014 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.