BERRY PETROLEUM CO
Form 10-Q
August 13, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2014
OR

¨ 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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ¨ No x
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 H(1)(a) and (b) of Form 10-Q 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-Q 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 x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x
On December 16, 2013, the registrant was acquired (see Note 1 of Notes to the Condensed 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.

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GLOSSARY OF TERMS

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

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.
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.
MMcf. One million cubic feet.
MMcf/d. MMcf per day.
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.

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PART I – FINANCIAL INFORMATION
Item 1. Financial Statements
BERRY PETROLEUM COMPANY, LLC
CONDENSED BALANCE SHEETS
(Unaudited)
(in thousands)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$2,489	$51,041
Accounts receivable – trade, net	156,577	122,855
Derivative instruments	2,070	5,596
Other current assets	30,235	30,833
Total current assets	191,371	210,325
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	5,126,125	4,813,659
Less accumulated depletion and amortization	(150,631)	(10,394)
	4,975,494	4,803,265
Other property and equipment	89,856	83,126
Less accumulated depreciation	(3,790)	(233)
	86,066	82,893
Derivative instruments	1,210	2,511
Other noncurrent assets	16,204	8,051
	17,414	10,562
Total noncurrent assets	5,078,974	4,896,720
Total assets	$5,270,345	$5,107,045
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$314,108	$264,271
Derivative instruments	31,575	20,393
Other accrued liabilities	19,560	28,993
Current portion of long-term debt	—	211,558
Total current liabilities	365,243	525,215
Noncurrent liabilities:		
Credit facility	1,173,175	1,173,175
Senior notes, net	914,680	916,428
Derivative instruments	—	4,649
Other noncurrent liabilities	184,591	192,091
Total noncurrent liabilities	2,272,446	2,286,343

Commitments and contingencies (Note 10)

Member's equity:		
Additional paid-in capital	2,493,923	2,315,460
Accumulated income (deficit)	138,733	(19,973)
	2,632,656	2,295,487
Total liabilities and member's equity	$5,270,345	$5,107,045

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

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

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$360,380	$274,715	$693,496	$541,487
Electricity sales	10,192	9,513	20,161	17,102
Gains (losses) on oil and natural gas derivatives	(25,562)	35,622	(22,097)	34,885
Marketing revenues	2,242	2,255	7,088	4,282
Other revenues	9	233	(7)	705
	347,261	322,338	698,641	598,461
Expenses:				
Lease operating expenses	93,354	79,759	183,385	155,027
Electricity generation expenses	7,629	6,337	16,012	11,633
Transportation expenses	7,483	8,293	15,476	15,987
Marketing expenses	2,096	2,198	4,694	4,076
General and administrative expenses	28,322	19,371	71,813	41,597
Exploration costs	—	872	—	4,301
Depreciation, depletion and amortization	77,753	70,272	146,384	138,750
Taxes, other than income taxes	23,479	14,229	46,508	28,199
(Gains) losses on sale of assets and other, net	4,257	—	7,624	(23)
	244,373	201,331	491,896	399,547
Other income and (expenses):				
Interest expense, net of amounts capitalized	(23,486)	(24,879)	(47,487)	(49,566)
Other, net	(445)	82	(634)	33
	(23,931)	(24,797)	(48,121)	(49,533)
Income before income taxes	78,957	96,210	158,624	149,381
Income tax expense (benefit)	(51)	34,846	(82)	55,583
Net income	$79,008	$61,364	$158,706	$93,798

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

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BERRY PETROLEUM COMPANY, LLC
CONDENSED STATEMENT OF MEMBER'S EQUITY
(Unaudited)
(in thousands)

	Additional Paid-In Capital	Accumulated Income (Deficit)	Total Member's Equity
December 31, 2013	$2,315,460	$(19,973)	$2,295,487
Capital contribution from affiliate	220,000	—	220,000
Distribution to affiliate	(41,537)	—	(41,537)
Net income	—	158,706	158,706
June 30, 2014	$2,493,923	$138,733	$2,632,656

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

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

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013
Cash flow from operating activities:		
Net income	$158,706	$93,798
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	146,384	138,750
Stock-based compensation expense	—	5,903
Amortization and write-off of deferred financing fees	(5,492)	3,438
Change in book overdraft	—	(14,885)
Deferred income taxes	(82)	61,639
Other, net	—	5,382
Derivatives activities:		
Total (gains) losses	22,097	(34,885)
Cash settlements	(10,472)	4,844
Changes in assets and liabilities:		
Increase in accounts receivable – trade, net	(34,294)	(16,518)
Decrease in other assets	1,486	242
Increase (decrease) in accounts payable and accrued expenses	11,869	(11,470)
Decrease in other liabilities	(25,473)	(4,278)
Net cash provided by operating activities	264,729	231,960
Cash flow from investing activities:		
Property acquisitions	—	(3,080)
Development of oil and natural gas properties	(269,129)	(302,724)
Purchases of other property and equipment	(5,625)	(3,954)
Proceeds from sale of properties and equipment and other	—	11,511
Net cash used in investing activities	(274,754)	(298,247)
Cash flow from financing activities:		
Proceeds from borrowings	—	490,700
Repayments of debt	(206,124)	(407,600)
Dividends paid	—	(8,803)
Financing fees and other, net	(10,866)	(223)
Proceeds from stock option exercises	—	65
Capital contribution from affiliate	220,000	—
Distribution to affiliate	(41,537)	—
Excess tax benefit from stock-based compensation	—	750
Net cash provided by (used in) financing activities	(38,527)	74,889
Net increase (decrease) in cash and cash equivalents	(48,552)	8,602
Cash and cash equivalents:		
Beginning	51,041	312
Ending	$2,489	$8,914

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

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BERRY PETROLEUM COMPANY, LLC
NOTES TO CONDENSED FINANCIAL STATEMENTS
(Unaudited)

Note 1 – Basis of Presentation

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, which includes California (South Midway-Sunset (“SMWSS”)—Steam Floods, North Midway-Sunset (“NMWSS”)—Diatomite and NMWSS—New Steam Flo (“NSF”)), Texas (Permian Basin and east Texas), Utah (Uinta Basin) and Colorado (Piceance Basin).

Principles of Reporting

The information reported herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for the fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) have been condensed or omitted under Securities and Exchange Commission (“SEC”) rules and regulations; as such, this report should be read in conjunction with the financial statements and notes in the Company’s Annual Report on Form 10-K for the year ended December 31, 2013. The results reported in these unaudited condensed financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

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), 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 includes 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 different basis of accounting between the periods presented.

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Use of Estimates

The preparation of the accompanying condensed 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 issued an Accounting Standards Update (“ASU”) that is intended to improve and converge the financial reporting requirements for revenue from contracts with customers. The 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.

Note 2 – Properties Exchange and LINN Energy Transaction

Properties Exchange – Pending

On May 20, 2014, the Company, along with a subsidiary of its indirect parent LINN Energy, entered into a definitive agreement to trade a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc., for operating interests in the Hugoton Basin. The Company anticipates the transaction will close in the third quarter of 2014, subject to closing conditions. There can be no assurance that all of the conditions to closing will be satisfied.

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 has a value of 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. The initial accounting for the business combination is not complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition date.

As a result of being formed as a limited liability company on December 16, 2013, the date of the LINN Energy transaction, the Company 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.

Note 3 – Oil and Natural Gas Properties

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:

	June 30, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas:		
Proved properties	$3,755,393	$3,397,785
Unproved properties	1,370,732	1,415,874
	5,126,125	4,813,659
Less accumulated depletion and amortization	(150,631)	(10,394)
	$4,975,494	$4,803,265

Note 4 – Debt

The following summarizes the Company's outstanding debt:

	June 30, 2014	December 31, 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	15,547	22,729
Total debt, net	2,087,855	2,301,161
Less current maturities	—	(211,558)
Total long-term debt, net	$2,087,855	$2,089,603

(1) Variable interest rates of 2.66% and 2.67% at June 30, 2014, and December 31, 2013, respectively.

Fair Value

The Company's debt is recorded at the carrying amount in the condensed 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.

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BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

	June 30, 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	914,680	948,212	1,127,986	1,128,527
Total debt, net	$2,087,855	$2,121,387	$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 June 30, 2014, lender commitments under the facility were $1.2 billion but the Company had 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, and in April 2014, the Company entered into an amendment to the Credit Facility to extend the maturity 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 that reflect commodity prices at such time, occurs semi-annually, in April and October. 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. The Company's obligations under the Credit Facility are secured by mortgages on its oil and natural gas properties and other personal property. The Company is required to maintain mortgages on properties representing at least 80% of the present value of its oil and natural gas proved reserves.

The Company is currently in compliance with all financial and other covenants of the 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.

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.

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.

Senior Notes Due September 2022

The Company has $599 million 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.

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.

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BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

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 11).

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 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.

Note 5 – Derivative Instruments

The Company hedges 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 current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company's ability to effectively hedge its NGL production. As a result, currently, the Company does not directly hedge its NGL production. The Company also, from time to time, enters into derivative contracts for a portion of its natural gas consumption.

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

The Company enters into these transactions with respect to a portion of its projected production 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 these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 6 for fair value disclosures about oil and natural gas commodity derivatives.

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BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

The following table summarizes derivative positions for the periods indicated as of June 30, 2014:

	July 1 - December 31, 2014	2015
Oil positions:		
Fixed price swaps (NYMEX WTI):		
Hedged volume (MBbls)	2,484	—
Average price ($/Bbl)	$91.26	$—
Collars (NYMEX WTI):		
Hedged volume (MBbls)	368	—
Average floor price ($/Bbl)	$90.00	$—
Average ceiling price ($/Bbl)	$102.87	$—
Three-way collars (NYMEX WTI):		
Hedged volume (MBbls)	1,564	1,095
Short put ($/Bbl)	$72.11	$70.00
Long put ($/Bbl)	$93.76	$90.00
Short call ($/Bbl)	$109.79	$101.62
Three-way collars (ICE Brent):		
Hedged volume (MBbls)	184	—
Short put ($/Bbl)	$80.00	$—
Long put ($/Bbl)	$100.00	$—
Short call ($/Bbl)	$114.05	$—
Oil basis differential positions:		
ICE Brent - NYMEX WTI basis swaps:		
Hedged volume (MBbls)	1,840	2,920
Hedged differential ($/Bbl)	$11.60	$11.60
Oil timing differential positions:		
Trade month roll swaps (NYMEX WTI): (1)		
Hedged volume (MBbls)	920	—
Hedged differential ($/Bbl)	$0.32	$—

(1) The Company hedges the timing risk associated with the sales price of oil in the Permian Basin. In this operating area, the Company generally sells oil for the delivery month at a sales price based on the average NYMEX WTI price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").

Settled derivatives on oil production for the three months and six months ended June 30, 2014, included volumes of 2,275 MBbls and 4,525 MBbls, respectively, 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.

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BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

Balance Sheet Presentation

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

	June 30, 2014	December 31, 2013
	(in thousands)	
Assets:		
Commodity derivatives	$17,004	$28,291
Liabilities:		
Commodity derivatives	$45,299	$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 $17 million at June 30, 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 losses of approximately $26 million and $22 million for the three months and six months ended June 30, 2014, respectively. Net losses for the three months and six months ended June 30, 2014, include cash settlement payments of approximately $8 million and $11 million, respectively. Gains and losses on oil and natural gas derivatives were net gains of approximately $36 million and $35 million for the three months and six months ended June 30, 2013, respectively. Net gains for the three months and six months ended June 30, 2013, include cash settlement receipts of approximately $3 million and $5 million, respectively. These amounts are reported on the condensed statements of operations in “gains (losses) on oil and natural gas derivatives.”

Note 6 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives at fair value (see Note 5) 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).

BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

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

	June 30, 2014		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$17,004	$(13,724)	$3,280
Liabilities:			
Commodity derivatives	$45,299	$(13,724)	$31,575

	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.

Note 7 – Asset Retirement Obligations

Asset retirement obligations associated with retiring tangible long-lived assets are recognized as a liability in the period in which a legal obligation is incurred and becomes determinable and 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 (2.0% for the six months ended June 30, 2014); and (iv) a credit-adjusted risk-free interest rate (average of 5.4% for the six months ended June 30, 2014). 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 (in thousands):

Asset retirement obligations at December 31, 2013	$94,830
Liabilities added from drilling	2,842
Current year accretion expense	2,649
Settlements	(3,266)
Asset retirement obligations at June 30, 2014	$97,055

Note 8 – 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. 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 purposes are reported in “income tax expense (benefit)” on the condensed statements of operations.

Note 9 – Equity Incentive Compensation Plans

The successor Company does not have any equity incentive compensation ("EIC") plans under which it grants stock awards and, therefore, recognized no direct stock compensation expense for the six months ended June 30, 2014. Prior to the LINN Energy transaction, the Company granted equity awards to its employees under its EIC plans. The total compensation expense recognized by the predecessor Company in the condensed statements of operations for grants under the Company's EIC plans was approximately \$3 million and \$6 million for the three months and six months ended June 30, 2013, respectively. In connection with the LINN Energy transaction, effective December 16, 2013, the predecessor Company's equity awards were exchanged for LinnCo common shares or LINN Energy equity awards.

Note 10 – Commitments and Contingencies

East Texas Gathering System

The Company has entered into certain long-term natural gas gathering agreements for its east Texas production. The agreements contain embedded leases and the transaction has been 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.

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.

Legal Matters

Department of the Interior Notice of Proposed Debarment

On June 14, 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.

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BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

Royalty Class Action
The Company is a defendant in a certain statewide royalty class action case in which the parties have entered into a settlement agreement to settle past claims for approximately $2.4 million. Subject to approval of the settlement agreement by the court, the Company anticipates distribution of settlement funds to begin late in the third quarter or early fourth quarter of 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 business, financial condition, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.
During the three months and six months ended June 30, 2014, and June 30, 2013, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.
Note 11 – Related Party Transactions
LINN Energy
All former employees of the Company that were retained after the LINN Energy transaction are now employed by 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 three months and six months ended June 30, 2014, the Company incurred management fee expenses of approximately $24 million and $60 million, respectively, for services provided by LOI.
During the second quarter of 2014, LINN Energy made a cash capital contribution of $220 million to the Company which was used to pay in full the remaining outstanding principal amount of its approximately $205 million June 2014 Senior Notes plus accrued interest. During the same period, the Company made a cash distribution of approximately $42 million to LINN Energy. The Company also has affiliated accounts payable due to LOI of approximately $26 million and $17 million at June 30, 2014, and December 31, 2013, respectively, included in “accounts payable and accrued expenses” on the condensed balance sheets.
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 three months and six months ended June 30, 2014, the Company paid approximately $98,000 and $176,000, respectively, 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.

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BERRY PETROLEUM COMPANY
NOTES TO THE CONDENSED FINANCIAL STATEMENTS – Continued
(Unaudited)

Note 12 – Supplemental Disclosures to the Condensed Balance Sheets and Condensed Statements of Cash Flows
"Other current assets" reported on the condensed balance sheets primarily consist of inventories. "Other accrued liabilities" reported on the condensed balance sheets include the following:

	June 30, 2014	December 31, 2013
	(in thousands)	
Accrued interest	$16,232	$18,926
Accrued compensation	—	6,749
Asset retirement obligations (current portion)	3,318	3,318
Other	10	—
	$19,560	$28,993

Supplemental disclosures to the condensed statements of cash flows are presented below:

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013
(in thousands)		
Cash payments for interest, net of amounts capitalized	$55,751	$43,197
Cash payments for income taxes	$—	$600
Noncash investing activities:		
Accrued capital expenditures	$38,969	$40,607
Asset retirement obligations	$2,842	$10,607

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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 set forth in "Cautionary Statement" below and in Item 1A. "Risk Factors" in this Quarterly Report on Form 10-Q and in the Annual Report on Form 10-K for the year ended December 31, 2013, and elsewhere in the Annual Report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

The following discussion and analysis should be read in conjunction with the financial statements and related notes included in this Quarterly Report on Form 10-Q and in the Company's Annual Report on Form 10-K for the year ended December 31, 2013. The reference to a "Note" herein refers to the accompanying Notes to Condensed Financial Statements contained in Item 1. "Financial Statements."

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 being acquired by LINN Energy in December 2013 (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's principal reserves and producing properties are located in California (South Midway-Sunset ("SMWSS")—Steam Floods, North Midway-Sunset ("NMWSS")—Diatomite, NMWSS—New Steam Floods ("NSF")), Texas (Permian Basin and east Texas), Utah (Uinta Basin) and Colorado (Piceance Basin).

Results for the three months ended June 30, 2014, included the following:

- oil, natural gas and NGL sales of approximately $360 million compared to $275 million for the second quarter of 2013;
- average daily production of 49.9 MBOE/d compared to 39.5 MBOE/d for the second quarter of 2013;
- net income of approximately $79 million compared to $61 million for the second quarter of 2013;
- capital expenditures, excluding acquisitions, of approximately $138 million compared to $130 million for the second quarter of 2013; and
- 117 wells drilled (all successful) compared to 78 wells drilled (all successful) for the second quarter of 2013.

Results for the six months ended June 30, 2014, included the following:

- oil, natural gas and NGL sales of approximately $693 million compared to $541 million for the six months ended June 30, 2013;
- average daily production of 48.7 MBOE/d compared to 39.6 MBOE/d for the six months ended June 30, 2013;
- net income of approximately $159 million compared to $94 million for the six months ended June 30, 2013;
- net cash provided by operating activities of approximately $265 million compared to $232 million for the six months ended June 30, 2013;
- capital expenditures, excluding acquisitions, of approximately $275 million compared to $307 million for the six months ended June 30, 2013; and
- 188 wells drilled (all successful) compared to 158 wells drilled (all successful) for the six months ended June 30, 2013.

LINN Energy Transaction

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. 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.

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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 had a preliminary value of 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 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.

Properties Exchange – Pending

On May 20, 2014, the Company, along with a subsidiary of its indirect parent LINN Energy, entered into a definitive agreement to trade a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc., for operating interests in the Hugoton Basin. The Company anticipates the transaction will close in the third quarter of 2014, subject to closing conditions. There can be no assurance that all of the conditions to closing will be satisfied.

Financing and Liquidity

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.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations
Three Months Ended June 30, 2014, Compared to Three Months Ended June 30, 2013

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance
(in thousands)			
Revenues and other:			
Oil sales	$330,820	$250,106	$80,714
Natural gas sales	24,444	18,033	6,411
NGL sales	5,116	6,576	(1,460)
Total oil, natural gas and NGL sales	360,380	274,715	85,665
Electricity sales	10,192	9,513	679
Gains (losses) on oil and natural gas derivatives	(25,562)	35,622	(61,184)
Marketing and other revenues	2,251	2,488	(237)
	347,261	322,338	24,923
Expenses:			
Lease operating expenses	93,354	79,759	13,595
Electricity generation expenses	7,629	6,337	1,292
Transportation expenses	7,483	8,293	(810)
Marketing expenses	2,096	2,198	(102)
General and administrative expenses	28,322	19,371	8,951
Exploration costs	—	872	(872)
Depreciation, depletion and amortization	77,753	70,272	7,481
Taxes, other than income taxes	23,479	14,229	9,250
Losses on sale of assets and other, net	4,257	—	4,257
	244,373	201,331	43,042
Other income and (expenses)	(23,931)	(24,797)	866
Income before income taxes	78,957	96,210	(17,253)
Income tax expense (benefit)	(51)	34,846	(34,897)
Net income	$79,008	$61,364	$17,644

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance	
Average daily production:				
Oil (MBbls/d)	38.2	29.4	30	%
Natural gas (MMcf/d)	61.8	48.4	28	%
NGL (MBbls/d)	1.3	2.1	(38	)%
Total (MBOE/d)	49.9	39.5	26	%
Weighted average price: [1]				
Oil (Bbl)	$95.06	$93.54	2	%
Natural gas (Mcf)	$4.34	$4.09	6	%
NGL (Bbl)	$43.03	$34.87	23	%
Average NYMEX prices:				
Oil (Bbl)	$102.99	$94.22	9	%
Natural gas (MMBtu)	$4.67	$4.09	14	%
Costs per BOE of production:				
Lease operating expenses	$20.58	$22.17	(7	)%
Transportation expenses	$1.65	$2.31	(29	)%
General and administrative expenses	$6.24	$5.39	16	%
Depreciation, depletion and amortization	$17.14	$19.54	(12	)%
Taxes, other than income taxes	$5.18	$3.96	31	%

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

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased by approximately $85 million or 31% to approximately $360 million for the three months ended June 30, 2014, from approximately $275 million for the three months ended June 30, 2013, due to higher production volumes and higher oil, natural gas and NGL prices. Higher oil, natural gas and NGL prices resulted in an increase in revenues of approximately $5 million, $1 million and $1 million, respectively.

Average daily production volumes increased to approximately 49.9 MBOE/d for the three months ended June 30, 2014, from 39.5 MBOE/d for the three months ended June 30, 2013. Higher oil and natural gas production volumes resulted in an increase in revenues of approximately $75 million and $5 million, respectively. Lower NGL production volumes resulted in a decrease in revenues of approximately $2 million.

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

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance		
Average daily production (MBOE/d):					
California	26.5	19.8	6.7	34	%
Uinta Basin	11.0	7.3	3.7	51	%
Permian Basin	8.8	8.0	0.8	10	%
Piceance Basin	1.9	2.3	(0.4)	(17	)%
East Texas	1.7	2.1	(0.4)	(19	)%
	49.9	39.5	10.4	26	%

The increase in average daily production volumes in California, the Uinta Basin and Permian Basin operating areas primarily reflect development capital spending. The decrease in average daily production volumes in the Piceance Basin and East Texas operating areas primarily reflect the effects of production declines due to reduced development capital spending.

Electricity Sales

The following table sets forth selected electricity data:

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance	
Electricity sales (in thousands)	$10,192	$9,513	7	%
Electricity generation expenses (in thousands)	$7,629	$6,337	20	%
Electric power produced (Mwh/d)	2,002	1,957	2	%
Electric power sold (Mwh/d)	1,820	1,772	3	%
Average sales price per Mwh	$61.47	$58.98	4	%
Fuel gas cost per MMBtu (including transportation)	$4.62	$3.95	17	%
Estimated natural gas volumes consumed to produce electricity (MMBtu/d) (1)	14,921	14,612	2	%

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

Electricity sales increased by approximately $679,000 or 7% to approximately $10 million for the three months ended June 30, 2014, primarily due to an increase in the average sales price of electricity and electric power sold during the period.

Gains (Losses) on Oil and Natural Gas Derivatives

Losses on oil and natural gas derivatives were approximately $26 million for the three months ended June 30, 2014, compared to gains of approximately $36 million for the three months ended June 30, 2013, representing a variance of approximately $62

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

million. Losses on oil and natural gas derivatives were primarily due to changes in fair value of the derivative contracts and lower 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 3. "Quantitative and Qualitative Disclosures About Market Risk" and Note 5 and Note 6 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" in "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 its capacity. To optimize its remaining capacity, the Company purchases third-party natural gas at the market rate in its producing areas and utilizes asset management agreements. Sales of third-party natural gas are recorded as marketing revenues. Marketing and other revenues decreased by approximately $237,000 or 10% to approximately $2 million for the three months ended June 30, 2014.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $13 million or 17% to approximately $93 million for the three months ended June 30, 2014, from approximately $80 million for the three months ended June 30, 2013. Lease operating expenses increased primarily due to an increase in steam costs caused by an increase in the price and volume of natural gas used in steam generation. Lease operating expenses per BOE decreased to $20.58 per BOE for the three months ended June 30, 2014, from $22.17 per BOE for the three months ended June 30, 2013, primarily due to higher production volumes.

The following table sets forth steam information:

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance	
Average net volume of steam injected (Bbls/d)	252,001	190,085	33	%
Fuel gas cost per MMBtu (including transportation)	$4.62	$3.95	17	%
Estimated natural gas volumes consumed to produce steam (MMBtu/d)	89,498	65,313	37	%

Electricity Generation Expenses

Electricity generation expenses increased by approximately $2 million or 20% to approximately $8 million for the three months ended June 30, 2014, from approximately $6 million for the three months ended June 30, 2013, primarily due to increases in fuel gas cost and fuel gas volumes purchased.

Transportation Expenses

Transportation expenses decreased by approximately $1 million or 10% to approximately $7 million for the three months ended June 30, 2014, from approximately $8 million for the three months ended June 30, 2013, primarily due to favorable marketing contract adjustments partially offset by higher expenses due to increased production volumes in the Uinta Basin.

Marketing Expenses

Marketing expenses primarily represent third-party activities associated with the Company’s long-term firm transportation contracts. The Company’s current production is insufficient to fully utilize its capacity. To optimize its remaining capacity, the Company purchases third-party natural gas at the market rate in its producing areas and utilizes asset management agreements. Purchases of third-party natural gas are recorded as marketing expenses. Marketing expenses decreased by approximately $102,000 or 5% to approximately $2 million for the three months ended June 30, 2014.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations. General and administrative expenses increased by approximately $9 million or 46% to approximately $28 million for the three months ended June 30, 2014, from approximately $19 million for the three months ended June 30, 2013. The increase was primarily due to higher personnel expenses, transition expenses, professional services expenses and various other administrative expenses. General and administrative expenses per BOE also increased to $6.24 per BOE for the three months ended June 30, 2014, from $5.39 per BOE for the three months ended June 30, 2013.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $8 million or 11% to approximately $78 million for the three months ended June 30, 2014, from approximately $70 million for the three months ended June 30, 2013. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per BOE decreased to $17.14 per BOE for the three months ended June 30, 2014, from $19.54 per BOE for the three months ended June 30, 2013, 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.

Taxes, Other Than Income Taxes

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance
(in thousands)			
Severance taxes	$5,823	$4,317	$1,506
Ad valorem taxes	13,112	6,687	6,425
California carbon allowances	4,520	3,225	1,295
Other	24	—	24
	$23,479	$14,229	$9,250

Taxes, other than income taxes increased by approximately $9 million or 65% for the three months ended June 30, 2014, compared to the three months ended June 30, 2013. Severance taxes, which are a function of revenues generated from production, increased primarily due to higher production volumes and higher oil, natural gas and NGL 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.

Other Income and (Expenses)

	Successor Three Months Ended June 30, 2014	Predecessor Three Months Ended June 30, 2013	Variance
(in thousands)			
Interest expense, net of amounts capitalized	$(23,486)	$(24,879)	$1,393
Other, net	(445)	82	(527)
	$(23,931)	$(24,797)	$866

Other income and (expenses) decreased by approximately $1 million for the three months ended June 30, 2014, compared to the three months ended June 30, 2013. Interest expense decreased primarily due to the amortization of premiums related to the Company's debt being recorded at fair value on December 16, 2013, the acquisition date, partially offset by higher outstanding debt during the period. See "Debt" in "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

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

was a Subchapter C-corporation subject to federal and state income taxes. The Company recognized an income tax benefit of approximately $51,000 for the three months ended June 30, 2014, compared to income tax expense of approximately $35 million for the three months ended June 30, 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.

Net Income

Net income increased by approximately $18 million or 29% to approximately $79 million for the three months ended June 30, 2014, from approximately $61 million for the three months ended June 30, 2013. The increase was primarily due to higher production revenues, partially offset by higher expenses and higher losses on oil and natural gas derivatives. See discussions above for explanations of variances.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations
Six Months Ended June 30, 2014, Compared to Six Months Ended June 30, 2013

(in thousands)	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance
Revenues and other:			
Oil sales	$625,721	$494,561	$131,160
Natural gas sales	53,389	34,028	19,361
NGL sales	14,386	12,898	1,488
Total oil, natural gas and NGL sales	693,496	541,487	152,009
Electricity sales	20,161	17,102	3,059
Gains (losses) on oil and natural gas derivatives	(22,097)	34,885	(56,982)
Marketing and other revenues	7,081	4,987	2,094
	698,641	598,461	100,180
Expenses:			
Lease operating expenses	183,385	155,027	28,358
Electricity generation expenses	16,012	11,633	4,379
Transportation expenses	15,476	15,987	(511)
Marketing expenses	4,694	4,076	618
General and administrative expenses	71,813	41,597	30,216
Exploration costs	—	4,301	(4,301)
Depreciation, depletion and amortization	146,384	138,750	7,634
Taxes, other than income taxes	46,508	28,199	18,309
(Gains) losses on sale of assets and other, net	7,624	(23)	7,647
	491,896	399,547	92,349
Other income and (expenses)	(48,121)	(49,533)	1,412
Income before income taxes	158,624	149,381	9,243
Income tax expense (benefit)	(82)	55,583	(55,665)
Net income	$158,706	$93,798	$64,908

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance	
Average daily production:				
Oil (MBbls/d)	36.9	29.3	26	%
Natural gas (MMcf/d)	59.5	49.8	19	%
NGL (MBbls/d)	1.8	2.0	(10	)%
Total (MBOE/d)	48.7	39.6	23	%
Weighted average price: [1]				
Oil (Bbl)	$93.72	$93.27	1	%
Natural gas (Mcf)	$4.95	$3.78	31	%
NGL (Bbl)	$43.04	$35.47	21	%
Average NYMEX prices:				
Oil (Bbl)	$100.84	$94.30	7	%
Natural gas (MMBtu)	$4.80	$3.71	29	%
Costs per BOE of production:				
Lease operating expenses	$20.82	$21.63	(4	)%
Transportation expenses	$1.76	$2.23	(21	)%
General and administrative expenses	$8.15	$5.80	41	%
Depreciation, depletion and amortization	$16.62	$19.36	(14	)%
Taxes, other than income taxes	$5.28	$3.93	34	%

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

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased by approximately $152 million or 28% to approximately $693 million for the six months ended June 30, 2014, from approximately $541 million for the six months ended June 30, 2013, due to higher production volumes and higher natural gas, oil and NGL prices. Higher natural gas, oil and NGL prices resulted in an increase in revenues of approximately $12 million, $3 million and $3 million, respectively.

Average daily production volumes increased to approximately 48.7 MBOE/d for the six months ended June 30, 2014, from 39.6 MBOE/d for the six months ended June 30, 2013. Higher oil and natural gas production volumes resulted in an increase in revenues of approximately $128 million and $7 million, respectively. Lower NGL production volumes resulted in a decrease in revenues of approximately $1 million.

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

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance	
Average daily production (MBOE/d):				
California	25.3	19.7	5.6	28 %
Uinta Basin	10.9	7.3	3.6	49 %
Permian Basin	8.8	8.1	0.7	9 %
Piceance Basin	2.0	2.4	(0.4)	(17)%
East Texas	1.7	2.1	(0.4)	(19)%
	48.7	39.6	9.1	23 %

The increase in average daily production volumes in California, the Uinta Basin and Permian Basin operating areas primarily reflect development capital spending. The decrease in average daily production volumes in the Piceance Basin and East Texas operating areas primarily reflect the effects of production declines due to reduced development capital spending.

Electricity Sales

The following table sets forth selected electricity data:

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance
Electricity sales (in thousands)	$20,161	$17,102	18 %
Electricity generation expenses (in thousands)	$16,012	$11,633	38 %
Electric power produced (Mwh/d)	2,055	1,996	3 %
Electric power sold (Mwh/d)	1,867	1,812	3 %
Average sales price per Mwh	$59.62	$51.76	15 %
Fuel gas cost per MMBtu (including transportation)	$5.09	$3.75	36 %
Estimated natural gas volumes consumed to produce electricity (MMBtu/d) (1)	15,344	14,684	4 %

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

Electricity sales increased by approximately $3 million or 18% to approximately $20 million for the six months ended June 30, 2014, from approximately $17 million for the six months ended June 30 2013, primarily due to an increase in the average sales price of electricity and electric power sold during the period.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Gains (Losses) on Oil and Natural Gas Derivatives

Losses on oil and natural gas derivatives were approximately $22 million for the six months ended June 30, 2014, compared to gains of approximately $35 million for the six months ended June 30, 2013, representing a variance of approximately $57 million. Losses on oil and natural gas derivatives were primarily due to the changes in fair value of the derivative contracts during the period and lower 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 3. "Quantitative and Qualitative Disclosures About Market Risk" and Note 5 and Note 6 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" in "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 its capacity. To optimize its remaining capacity, the Company purchases third-party natural gas at the market rate in its producing areas and utilizes asset management agreements. Sales of third-party natural gas are recorded as marketing revenues. Marketing and other revenues increased by approximately $2 million or 42% to approximately $7 million for the six months ended June 30, 2014, from approximately $5 million for the six months ended June 30, 2013, primarily due to an increase in natural gas prices during the first quarter of 2014.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $28 million or 18% to approximately $183 million for the six months ended June 30, 2014, from approximately $155 million for the six months ended June 30, 2013. Lease operating expenses increased primarily due to an increase in steam costs caused by an increase in the price and volume of natural gas used in steam generation. Lease operating expenses per BOE decreased to $20.82 per BOE for the six months ended June 30, 2014, from $21.63 per BOE for the six months ended June 30, 2013, primarily due to higher production volumes.

The following table sets forth steam information:

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance	
Average net volume of steam injected (Bbls/d)	241,934	193,936	25	%
Fuel gas cost per MMBtu (including transportation)	$5.09	$3.75	36	%
Estimated natural gas volumes consumed to produce steam (MMBtu/d)	86,447	65,724	32	%

Electricity Generation Expenses

Electricity generation expenses increased by approximately $4 million or 38% to approximately $16 million for the six months ended June 30, 2014, from approximately $12 million for the six months ended June 30, 2013, primarily due to increases in fuel gas cost and fuel gas volumes purchased.

Transportation Expenses

Transportation expenses decreased by approximately $1 million or 3% to approximately $15 million for the six months ended June 30, 2014, from approximately $16 million for the six months ended June 30, 2013, primarily due to favorable marketing contract adjustments partially offset by higher expenses due to increased production volumes in the Uinta Basin.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

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 purchases third-party natural gas at the market rate in its producing areas and utilizes asset management agreements. Purchases of third-party natural gas are recorded as marketing expenses. Marketing expenses increased by approximately $1 million or 15% to approximately $5 million for the six months ended June 30, 2014, from approximately $4 million for the six months ended June 30, 2013, primarily due to an increase in natural gas prices during the first quarter of 2014.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations. General and administrative expenses increased by approximately $30 million or 73% to approximately $72 million for the six months ended June 30, 2014, from approximately $42 million for the six months ended June 30, 2013. The increase was primarily due to higher share-based compensation allocated to the Company by LOI during the first quarter of 2014, which is expected to decrease over the remainder of the year, as well as higher personnel expenses, transition expenses, professional services expenses and various other administrative expenses. General and administrative expenses per BOE also increased to $8.15 million per BOE for the six months ended June 30, 2014, from $5.80 per BOE for the six months ended June 30, 2013.

Exploration Costs

The Company recorded no exploration costs for the six months ended June 30, 2014. For the six months ended June 30, 2013, the Company recorded exploration costs of approximately $4 million primarily related to the expiration of certain undeveloped leases in the Permian Basin.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $7 million or 6% to approximately $146 million for the six months ended June 30, 2014, from approximately $139 million for the six months ended June 30, 2013. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per BOE decreased to $16.62 per BOE for the six months ended June 30, 2014, from $19.36 per BOE for the six months ended June 30, 2013, 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.

Taxes, Other Than Income Taxes

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance
(in thousands)			
Severance taxes	$11,242	$8,343	$2,899
Ad valorem taxes	26,353	13,445	12,908
California carbon allowances	8,888	6,411	2,477
Other	25	—	25
	$46,508	$28,199	$18,309

Taxes, other than income taxes increased by approximately $18 million or 65% for the six months ended June 30, 2014, compared to the six months ended June 30, 2013. Severance taxes, which are a function of revenues generated from production, increased primarily due to higher production volumes and higher natural gas, oil and NGL 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.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Other Income and (Expenses)

	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance
(in thousands)			
Interest expense, net of amounts capitalized	$(47,487)	$(49,566)	$2,079
Other, net	(634)	33	(667)
	$(48,121)	$(49,533)	$1,412

Other income and (expenses) decreased by approximately $1 million for the six months ended June 30, 2014, compared to the six months ended June 30, 2013. Interest expense decreased primarily due to the amortization of premiums related to the Company's debt being recorded at fair value on December 16, 2013, the acquisition date, partially offset by higher outstanding debt during the period. See "Debt" in "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. The Company recognized an income tax benefit of approximately $82,000 for the six months ended June 30, 2014, compared to income tax expense of approximately $56 million for the six months ended June 30, 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.

Net Income

Net income increased by approximately $65 million or 69% to approximately $159 million for the six months ended June 30, 2014, from approximately $94 million for the six months ended June 30, 2013. The increase was primarily due to higher production revenues, partially offset by higher expenses and higher losses on oil and natural gas derivatives. 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 acquisitions and the development of oil and natural gas properties. For the six months ended June 30, 2014, the Company's total capital expenditures were approximately $275 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 June 30, 2014, the Company had less than $1 million of available borrowing capacity under its 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 and is not currently being distributed to LINN Energy for further distribution to its unitholders. To the extent that the Company generates cash in excess

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

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 was approximately $266 million at June 30, 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 11).

Statements of Cash Flows

The following is a comparative cash flow summary:

(in thousands)	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013	Variance
Net cash:			
Provided by operating activities	$264,729	$231,960	$32,769
Used in investing activities	(274,754)	(298,247)	23,493
Provided by (used in) financing activities	(38,527)	74,889	(113,416)
Net increase (decrease) in cash and cash equivalents	$(48,552)	$8,602	$(57,154)

Operating Activities

Cash provided by operating activities for the six months ended June 30, 2014, was approximately $265 million, compared to approximately $232 million for the six months ended June 30, 2013. The increase was primarily due to higher production related revenues principally due to increased oil and natural gas production volumes and higher commodity prices, partially offset by higher expenses and lower cash settlements on derivatives.

Investing Activities

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

(in thousands)	Successor Six Months Ended June 30, 2014	Predecessor Six Months Ended June 30, 2013
Cash flow from investing activities:		
Property acquisitions	$—	$(3,080)
Capital expenditures	(274,754)	(306,678)
Proceeds from sale of properties and equipment and other	—	11,511
	$(274,754)	$(298,247)

The primary use of cash in investing activities is for the development of the Company's oil and natural gas properties. Capital expenditures decreased primarily due to lower spending on development activities during 2014.

Financing Activities

Cash used in financing activities of approximately $39 million for the six months ended June 30, 2014, was primarily related to a cash distribution of approximately $42 million made to LINN Energy during the second quarter of 2014. Cash provided by financing activities for the six months ended June 30, 2013, included net borrowings of approximately $83 million under the Company's Credit Facility.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

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 June 30, 2014, lender commitments under the facility were $1.2 billion but the Company had 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, and in April 2014, the Company entered into an amendment to the Credit Facility to extend the maturity from May 2016 to April 2019 and to amend the terms of certain financial covenants and definitions, among other items.

As of June 30, 2014, the Company was 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 4.

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.

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 11).

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.

Off-Balance Sheet Arrangements

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

Contingencies

See Part II. Item 1. "Legal Proceedings" for information regarding legal proceedings that the Company is party to and any contingencies related to these legal proceedings.

Commitments and Contractual Obligations

The Company has contractual obligations for long-term debt, operating leases and other long-term liabilities that were summarized in the table of contractual obligations in the 2013 Annual Report on Form 10-K. With the exceptions of: (i) the Company's payment of the remaining outstanding principal amount of the June 2014 Senior Notes and (ii) an amendment to the Company's Credit Facility that extended the maturity date from May 2016 to April 2019, there have been no significant changes to the Company's contractual obligations from December 31, 2013. See Note 4 for additional information about the Company's debt instruments.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the condensed financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires management of the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities,

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

revenues and expenses, and related disclosures of contingent assets and liabilities. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors that are believed to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. Actual results may differ from these estimates and assumptions used in the preparation of the financial statements.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1 of Notes to Condensed Financial Statements.

Cautionary Statement

This Quarterly Report on Form 10-Q 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 content about the Company'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 business and operations acquired in the properties exchange, 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 Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of su other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q are not guarantees of future performance, and it cannot assure any reader that such statements will be realized or the forward-looking statements or events will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements due to factors set forth in Item 1A. "Risk Factors" in the Annual Report on Form 10-K for the year ended December 31, 2013, and elsewhere in the Annual Report. 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 3. 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

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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 Quarterly Report on Form 10-Q and in the Company's 2013 Annual Report on Form 10-K. The reference to a "Note" herein refers to the accompanying Notes to Condensed Financial Statements contained in Item 1. "Financial Statements."

Commodity Price Risk

An important part of the Company's business strategy includes hedging a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil and, from time to time, natural gas and provide long-term cash flow predictability to manage its business. By removing a significant 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 enters 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.

At June 30, 2014, the fair value of fixed price swaps, collars and three-way collars was a net liability of approximately $33 million. A 10% increase in the index oil price above the June 30, 2014, price would result in a net liability of approximately $80 million, which represents a decrease in the fair value of approximately $47 million; conversely, a 10% decrease in the index oil price below the June 30, 2014, price would result in a net asset of approximately $8 million, which represents an increase in the fair value of approximately $41 million. At June 30, 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 June 30, 2014, and

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Item 3. Quantitative and Qualitative Disclosures About Market Risk - Continued

December 31, 2013, 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 flow and ability to pay distributions could be impacted.

Interest Rate Risk

At June 30, 2014, the Company had long-term debt outstanding under its Credit Facility of approximately $1.2 billion which incurred interest at floating rates (see Note 4). A 1% increase in the London Interbank Offered Rate ("LIBOR") would result in an estimated $12 million increase in annual interest expense.

At 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. A 1% increase in the LIBOR 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 6). 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 June 30, 2014, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 0.87%. A 1% increase in the average public bond yield spread would result in an estimated $71,000 increase in net income for the six months ended June 30, 2014. At June 30, 2014, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0.06% and 0.55%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $13,000 decrease in net income for the six months ended June 30, 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.

Item 4. 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 June 30, 2014.

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Item 4. Controls and Procedures - Continued

Changes in the Company’s Internal Control Over Financial Reporting

The Company’s management is also responsible for establishing and maintaining adequate internal controls 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 condensed 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 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 controls over financial reporting during the second quarter of 2014 that materially affected, or were reasonably likely to materially affect, the Company’s internal control over financial reporting. LINN Energy continues to integrate certain business operations, information systems, processes and related internal control over financial reporting as a result of the acquisition of the Company. The Company will continue to assess the effectiveness of its internal control over financial reporting as integration activities continue.

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Part II – Other Information

Item 1. Legal Proceedings

Department of the Interior Notice of Proposed Debarment

On June 14, 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 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 in which the parties have entered into a settlement agreement to settle past claims for approximately $2.4 million. Subject to approval of the settlement agreement by the court, the Company anticipates distribution of settlement funds to begin late in the third quarter or early fourth quarter of 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 business, financial condition, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, results of operations or liquidity are described in Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2013. As of the date of this report, these risk factors have not changed materially. This information should be considered carefully, together with other information in this report and other reports and materials we file with the United States Securities and Exchange Commission.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

This item is intentionally omitted from this report pursuant to the reduced disclosure format permitted by General Instruction H to Form 10 Q.

Item 3. Defaults Upon Senior Securities

This item is intentionally omitted from this report pursuant to the reduced disclosure format permitted by General Instruction H to Form 10 Q.

Item 4. Mine Safety Disclosures

Not applicable

Item 5. Other Information

None

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Item 6. 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 Registration Statement on Form S-4 (File No. 333-187458) filed by Linn Energy, LLC 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 Registration Statement on Form S-4 (File No. 333-187458) filed by Linn Energy, LLC on May 28, 2014)
10.2	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 by reference to Exhibit 10.4 to Linn Energy, LLC's Quarterly Report on Form 10-Q filed on May 1, 2014)
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
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.

** Furnished herewith.

† The schedules to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such schedules to the Securities and Exchange Commission upon request.

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SIGNATURE

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

	BERRY PETROLEUM COMPANY, LLC (Registrant)
Date: August 13, 2014	/s/ David B. Rottino David B. Rottino Executive Vice President, Business Development and Chief Accounting Officer (As Duly Authorized Officer and Chief Accounting Officer)