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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2018

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 001-38606

BERRY PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**81-5410470**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

16000 Dallas Parkway, Suite 500
Dallas, Texas 75248
(661) 616-3900
(Address of principal executive offices, including zip code
Registrant's telephone number, including area code):

5201 Truxtun Avenue
Bakersfield, California 93309
(Former name, former address and former fiscal year, if changed since last report)

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 ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer x	Smaller reporting company ☐
Emerging Growth Company ☒			

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

Shares of common stock outstanding as of October 31, 2018 81,642,953

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The financial information and certain other information presented in this Form 10-Q have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables. In addition, certain percentages presented here reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, or may not sum due to rounding.

PART I – FINANCIAL INFORMATION
Item 1. Financial Statements (unaudited)

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	Berry Corp. (Successor)	
	September 30, 2018	December 31, 2017
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,856	$ 33,905
Accounts receivable, net of allowance for doubtful accounts of $950 at September 30, 2018 and $970 at December 31, 2017	65,757	54,720
Restricted cash	57	34,833
Other current assets	13,233	14,066
Total current assets	102,903	137,524
Noncurrent assets:		
Oil and natural gas properties	1,419,589	1,342,453
Accumulated depletion and amortization	(106,128)	(54,785)
Total oil and natural gas properties, net	1,313,461	1,287,668
Other property and equipment	116,149	104,879
Accumulated depreciation	(11,244)	(5,356)
Total other property and equipment, net	104,905	99,523
Other noncurrent assets	18,338	21,687
Total assets	$ 1,539,607	$ 1,546,402
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 117,801	$ 97,877
Derivative instruments	26,409	49,949
Liabilities subject to compromise	57	34,833
Total current liabilities	144,267	182,659
Noncurrent liabilities:		
Long-term debt	391,512	379,000
Derivative instruments	4,664	25,332
Deferred income taxes	5,033	1,888
Asset retirement obligation	89,404	94,509
Other noncurrent liabilities	15,617	3,704
Commitments and Contingencies - Note 5		
Equity:		
Series A preferred stock ($.001 par value, 250,000,000 shares authorized and none outstanding at September 30, 2018 and 35,845,001 shares outstanding at December 31, 2017)	—	335,000
Common stock ($.001 par value, 750,000,000 shares authorized and 81,364,933 shares outstanding at September 30, 2018 and 32,920,000 outstanding at December 31, 2017)	81	33
Additional paid-in-capital	915,028	545,345
Treasury stock, at cost	(20,265)	—
Retained earnings (Accumulated deficit)	(5,734)	(21,068)
Total equity	889,110	859,310
Total liabilities and equity	$ 1,539,607	$ 1,546,402

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Berry Corp. (Successor)				Berry LLC (Predecessor)
	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands, except per share amounts)				
Revenues and other:					
Oil, natural gas and natural gas liquids sales	$ 147,004	$ 101,763	$ 410,013	$ 237,324	$ 74,120
Electricity sales	14,268	8,914	25,691	15,517	3,655
Gains (losses) on oil derivatives	(18,994)	(42,443)	(131,781)	5,642	12,886
Marketing revenues	486	811	1,788	1,901	633
Other revenues	183	865	500	3,902	1,424
Total revenues and other	142,947	69,910	306,211	264,286	92,718
Expenses and other:					
Lease operating expenses	51,649	46,224	137,468	105,014	28,238
Electricity generation expenses	6,130	4,580	13,855	10,193	3,197
Transportation expenses	2,318	5,586	7,640	18,645	6,194
Marketing expenses	437	674	1,424	1,674	653
General and administrative expenses	13,429	11,729	37,896	43,529	7,964
Depreciation, depletion, amortization and accretion	21,729	20,822	62,017	48,393	28,149
Taxes, other than income taxes	8,317	11,782	25,288	25,112	5,212
(Gains) losses on natural gas derivatives	(1,879)	—	(1,879)	—	—
(Gains) losses on sale of assets and other, net	400	(20,692)	522	(20,687)	(183)
Total expenses and other	102,530	80,705	284,231	231,873	79,424
Other income (expenses):					
Interest expense	(9,877)	(5,882)	(26,828)	(12,482)	(8,245)
Other, net	347	1,155	135	4,071	(63)
Total other income (expenses)	(9,530)	(4,727)	(26,693)	(8,411)	(8,308)
Reorganization items, net	13,781	(408)	23,192	(1,001)	(507,720)
Income (loss) before income taxes	44,668	(15,930)	18,479	23,001	(502,734)
Income tax expense (benefit)	7,683	(6,246)	3,145	9,189	230
Net income (loss)	36,985	(9,684)	15,334	13,812	$ (502,964)
Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(97,942)	(12,681)	n/a
Net income (loss) attributable to common stockholders	$ (49,657)	$ (15,169)	$ (82,608)	$ 1,131	n/a
Net income (loss) per share attributable to common stockholders:					
Basic	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a
Diluted	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Berry Corp. (Successor)					
	Nine-Month Period Ended September 30, 2018					
	Series A Preferred Stock	Common Stock	Additional Paid in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
	(in thousands)					
December 31, 2017	$ 335,000	$ 33	$ 545,345	$ —	$ (21,068)	$ 859,310
Stock based compensation	—	—	1,042	—	—	1,042
Cash dividends declared on Series A preferred stock, $0.158/share	—	—	(5,650)	—	—	(5,650)
Net income	—	—		—	6,410	6,410
March 31, 2018	335,000	33	540,737	—	(14,658)	861,112
Stock based compensation	—	—	1,278	—	—	1,278
Shares withheld for payment of taxes on equity awards	—	—	(176)	—	—	(176)
Cash dividends declared on Series A preferred stock, $0.15/share	—	—	(5,651)	—	—	(5,651)
Purchase of rights to common stock	—	—	—	(20,006)	—	(20,006)
Net loss	—	—	—	—	(28,061)	(28,061)
June 30, 2018	335,000	33	536,188	(20,006)	(42,719)	808,496
Conversion of Series A preferred stock into common stock	(335,000)	40	334,960	—	—	—
Cash payment to Series A preferred stockholders	—	—	(60,273)	—	—	(60,273)
Issuance of common stock in initial public offering	—	10	134,352	—	—	134,362
Repurchase of common stock	—	(2)	(23,710)	—	—	(23,712)
Shares withheld for payment of taxes on equity awards	—	—	(246)	—	—	(246)
Stock based compensation	—	—	1,188	—	—	1,188
Purchase of rights to common stock	—	—	—	(259)	—	(259)
Dividends declared on common stock, $0.09/share	—	—	(7,431)	—	—	(7,431)
Net income	—	—	—	—	36,985	36,985
September 30, 2018	$ —	$ 81	$ 915,028	$ (20,265)	$ (5,734)	$ 889,110

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Nine-Month Period Ended September 30, 2017, including Successor and Predecessor Periods					
	Series A Preferred Stock	**Common Stock**	**Additional Paid in Capital**	**Treasury Stock**	**Retained Earnings (Accumulated Deficit)**	**Total Equity**
December 31, 2016	$ —	$ —	$ 2,798,713	$ —	$ (2,295,750)	$ 502,963
Net loss	—	—	—	—	(502,964)	(502,964)
Other	—	—	1	—	—	1
Cancellation of Predecessor Equity	—	—	(2,798,714)	—	2,798,714	—
Predecessor February 28, 2017	—	—	—	—	—	—
Issuance of Series A convertible preferred stock	335,000	—	—	—	—	335,000
Issuance of common stock	—	33	527,794	—	—	527,827
Fresh start ad valorem tax reclassification	—	—	15,700	—	—	15,700
Successor February 28, 2017	335,000	33	543.494	—	—	878,527
Net income	—	—	—	—	11,377	11,377
March 31, 2017	335,000	33	543,494	—	11,377	889,904
Net income	—	—	—	—	12,119	12,119
June 30, 2017	335,000	33	543,494	—	23,496	902,023
Stock based compensation	—	—	902	—	—	902
Net loss	—	—	—	—	(9,684)	(9,684)
September 30, 2017	$ 335,000	$ 33	$ 544,396	$ —	$ 13,812	$ 893,241

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
		(in thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 15,334	$ 13,812	$ (502,964)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion, amortization and accretion	62,017	48,393	28,149
Amortization and write-off of deferred financing fees	4,042	926	416
Stock-based compensation expense	3,502	902	—
Deferred income taxes	3,146	7,196	9
(Decrease) increase in allowance for doubtful accounts	(20)	970	—
Derivative activities:			
Total (gains) losses	129,902	(5,642)	(12,886)
Cash settlements	(47,161)	9,902	534
Cash settlements on early-terminated derivatives	(126,949)	—	—
(Gains) losses on sale of assets and other, net	522	(20,687)	(25)
Reorganization items, net	(24,199)	1,376	501,872
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(11,546)	(3,095)	(9,152)
(Increase) decrease in other assets	(774)	(11,397)	(2,842)
Increase (decrease) in accounts payable and accrued expenses	5,574	11,416	18,330
Increase (decrease) in other liabilities	(6,056)	16,433	990
Net cash provided by (used in) operating activities	7,334	70,505	22,431
Cash flows from investing activities:			
Capital expenditures:			
Development of oil and natural gas properties	(74,447)	(38,445)	(859)
Purchases of other property and equipment	(11,305)	(11,497)	(2,299)
Proceeds from sale of property, plant, equipment and other	3,377	234,823	25
Acquisition of properties	—	(259,444)	—
Net cash used in investing activities	(82,375)	(74,563)	(3,133)
Cash flows from financing activities:			
Repayments on new credit facility	(576,210)	(11,800)	—
Borrowings under new credit facility	197,210	390,800	—
IPO proceeds net of issuance costs	134,362	—	—
Repurchase of common stock	(23,712)	—	—
Payment to preferred stockholders in conversion	(60,273)	—	—
Issuance of 2026 Senior Unsecured Notes	400,000	—	—
Dividends paid on Series A preferred stock	(11,301)	—	—
Purchase of treasury stock	(20,265)	—	—
Shares withheld for payment of taxes on equity awards	(422)	—	—
Debt issuance costs	(9,173)	(22,049)	—
Borrowings on emergence credit facility	—	51,000	—
Repayments on emergence credit facility	—	(451,000)	—
Proceeds from sale of Series A preferred stock	—	—	335,000
Repayments on pre-emergence credit facility	—	—	(497,668)
Net cash provided by (used in) financing activities	30,216	(43,049)	(162,668)
Net decrease in cash, cash equivalents and restricted cash	(44,825)	(47,107)	(143,370)
Cash, cash equivalents and restricted cash:			
Beginning	68,738	85,034	228,404
Ending	$ 23,913	$ 37,927	$ 85,034

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

Note 1 - Basis of Presentation

"Berry Corp." refers to Berry Petroleum Corporation, a Delaware corporation which, on and after February 28, 2017 is the sole member of Berry Petroleum Company, LLC.

"Berry LLC" refers to Berry Petroleum Company, LLC, a Delaware limited liability company.

As the context may require, the "Company", "we", "our" or similar words refer to (i) Berry Corp. (the "Successor") and Berry LLC, its consolidated subsidiary, as of and after February 28, 2017, as a whole or (ii) either Berry Corp. or Berry LLC on an individual basis as of and after February 28, 2017. References to historical activities of the "Company" prior to February 28, 2017, refer to activities of Berry LLC (the "Predecessor").

"Linn Energy" refers to Linn Energy, LLC, a Delaware limited liability company of which Berry LLC was formerly a wholly-owned, indirect subsidiary and LinnCo, LLC ("LinnCo" and, together with Linn Energy, the "Linn Entities").

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law on February 13, 2017. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located in the United States ("U.S."), in California (in the San Joaquin and Ventura Basins), Utah (in the Uinta Basin), Colorado (in the Piceance Basin) and east Texas.

In July, we completed the initial public offering ("IPO") of our common stock and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY.

Principles of Consolidation and Reporting

The information reported herein reflects all adjustments (consisting of normal recurring adjustments) that are, in the opinion of management, necessary for the fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted under Securities and Exchange Commission ("SEC") rules and regulations. The results reported in these unaudited condensed consolidated financial statements may not accurately forecast results for future periods. This report should be read in conjunction with the financial statements and notes in the Company's audited financial statements for the year ended December 31, 2017 presented in our final prospectus dated July 25, 2018 as filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on July 27, 2018 (the "prospectus").

The condensed consolidated financial statements have been prepared in conformity with GAAP and include the accounts of the Successor and its wholly owned subsidiary after February 28, 2017 and the accounts of the Predecessor prior to February 28, 2017. All significant intercompany transactions and balances have been eliminated upon consolidation. For oil and gas exploration and production joint ventures in which we have a direct working interest, we account for our proportionate share of assets, liabilities, revenue, expense and cash flows within the relevant lines of the financial statements.

Bankruptcy Accounting

Upon emergence from bankruptcy on February 28, 2017, we adopted fresh start accounting which resulted in Berry Corp. becoming the financial reporting entity. As a result of the application of fresh start accounting and the effects of the implementation of the Plan (see Note 2 for definition), the condensed consolidated financial statements on or after February 28, 2017 are not comparable to the condensed consolidated financial statements prior to that date.

Use of Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with GAAP required management of the Company to make informed estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses.

As fair value is a market-based measurement, it was determined based on the assumptions that we believe market participants would use. We based these assumptions on management's best estimates and judgment. Management evaluates its assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, that management believes to be reasonable under the circumstances. Such assumptions are adjusted when management determines that facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates.

Estimates that are particularly significant to our financial statements include estimates of our reserves of oil and gas, future cash flows from oil and gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. In addition, as part of fresh-start accounting, we made estimates and assumptions related to our reorganization value, liabilities subject to compromise and the fair value of assets and liabilities recorded.

Accounting and Disclosure Changes

Recently Adopted Accounting Standards

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

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

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

New Accounting Standards Issued, But Not Yet Adopted

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

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

Note 2 - Emergence from Voluntary Reorganization under Chapter 11

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

Reorganization Items, Net

We have incurred and continue to incur expenses associated with the reorganization. Reorganization items, net represent costs and gains directly associated with the Chapter 11 Proceeding, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined. The following table summarizes the components of reorganization items included on the condensed consolidated statements of operations:

	Berry Corp. (Successor)				Berry LLC (Predecessor)
	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)				
Return of undistributed funds from Cash Distribution Pool [1]	$ 13,799	$ —	$ 22,799	$ —	$ —
Refund of pre-emergence prepaid costs	—	—	579	—	—
Gain on resolution of pre-emergence liabilities	—	—	1,634	—	—
Linn Energy bankruptcy claim receipt	1,500	—	1,500	—	—
Gain on settlement of liabilities subject to compromise	—	—	—	—	421,774
Fresh start valuation adjustments	—	—	—	—	(920,699)
Legal and other professional advisory fees	(713)	(408)	(2,515)	(296)	(19,481)
Other	(805)	—	(805)	(705)	10,686
Reorganization items, net	$ 13,781	$ (408)	$ 23,192	$ (1,001)	$ (507,720)

(1) Among other things, the holders of our Predecessor's Unsecured Notes (as defined below) received a right to their pro rata share of either 32,920,000 shares of common stock in Berry Corp. or, for those non-accredited investors holding our Predecessor's unsecured notes (the "Unsecured Notes") that irrevocably elected to receive a cash recovery, cash distributions from a $35 million cash distribution pool (the “Cash Distribution Pool”).

Liabilities Subject to Compromise

Liabilities subject to compromise related to our 2017 emergence from bankruptcy decreased from approximately $35 million as of December 31, 2017 to approximately $0.1 million as of September 30, 2018. Activity for our liabilities subject to compromise for the nine months ended September 30, 2018 included the return of $23 million in undistributed funds from restricted cash and approximately $12 million in settlement payments to general unsecured creditors and other payments of professional fees incurred to settle these claims.

Note 3 - Debt

The following table summarizes our outstanding debt:

	September 30, 2018	December 31, 2017	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ —	$ 379,000	variable rates of 4.5% (2018) and 4.8% (2017), respectively	June 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves
2026 Notes	400,000	—	7.00%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	379,000			
Less: Debt Issuance Costs	(8,488)	—			
Long-Term Debt, net	$ 391,512	$ 379,000			

At September 30, 2018 and December 31, 2017, debt issuance costs for the RBL Facility (as defined below) reported in "other noncurrent assets" on the balance sheet were approximately $17 million and $21 million net of amortization, respectively. The amortization of debt issuance costs is presented in interest expense on the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amount of the RBL Facility approximates fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 senior unsecured notes was approximately $416 million at September 30, 2018.

Credit Facilities

On July 31, 2017, we entered into a credit agreement (“RBL Facility”), with Wells Fargo Bank, N.A. as administrative agent and certain lenders with up to $1.5 billion of commitments, subject to a reserves-based borrowing base. In connection with the issuance of the 2026 Notes (as defined below), the RBL Facility borrowing base was set at $400 million, which incorporated a $100 million reduction, or 25% of the face value of the 2026 Notes. In March 2018, we completed a borrowing base redetermination which reaffirmed our borrowing base at $400 million with an elected commitment feature that allows us to increase the RBL Facility to $575 million with lender approval.

As of September 30, 2018, the financial performance covenants under our RBL Facility were (i) a leverage ratio of no more than 4.00 to 1.00 and (ii) a current ratio of at least 1.00 to 1.00. At September 30, 2018, our actual ratios were 1.85 to 1.00 and 4.21 to 1.00, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants as of September 30, 2018.

As of September 30, 2018, we had approximately $393 million of available borrowing capacity under the RBL Facility.

As of September 30, 2018 and December 31, 2017, we had letters of credit outstanding of approximately $7 million and $21 million, respectively, under our RBL facility. These letters of credit were issued to support ordinary course of business marketing, insurance, regulatory and other matters.

In July and August 2018, we paid down approximately $105 million on the RBL Facility from the net proceeds we received in the IPO of our common stock (see Note 6).

Senior Unsecured Notes Offering

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

Note 4 - Derivatives

We have hedged a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices and we target covering our operating expenses and fixed charges, including maintenance capital expenditures, for up to two years out. We have hedged a portion of our exposure to differentials between Intercontinental Exchange ("ICE") Brent oil ("Brent") and New York Mercantile Exchange ("NYMEX") West Texas Intermediate oil ("WTI") as well. From time to time we have entered into agreements to purchase a portion of the natural gas we require for our operations that we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

Our current hedge positions primarily consist of swap contracts and deferred premium purchased put options. In addition, we recently acquired natural gas fixed price swaps to manage our exposure to increases in natural gas prices. We enter into these transactions with respect to a portion of our projected oil production and gas purchases to provide economic hedges against the risk related to the future commodity prices. We do not enter into derivative contracts for speculative trading purposes. We did not designate any of our contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. Gains (losses) on oil hedges are classified in the revenues and other section of the statement of operations and gains (losses) on natural gas hedges are presented in the expenses and other section of the statement of operations.

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

	Q4 2018	FY 2019	FY 2020
Sold Oil Calls (ICE Brent):			
Hedged volume (MBbls)	124	—	—
Weighted-average price ($/Bbl)	$ 80.00	$ —	$ —
Purchased Oil Put Options (ICE Brent):			
Hedged volume (MBbls)	—	3,385	455
Weighted-average price ($/Bbl)	$ —	$ 65.00	$ 65.00
Fixed Price Oil Swaps (ICE Brent):			
Hedged volume (MBbls)	1,058	2,640	—
Weighted-average price ($/Bbl)	$ 74.82	$ 75.40	$ —
Oil basis differential positions:			
ICE Brent-NYMEX WTI basis swaps			
Hedged volume (MBbls)	92	182.5	—
Weighted-average price ($/Bbl)	$ 1.29	$ 1.29	$ —
Fixed Price Gas Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	1,380,000	4,560,000	—
Weighted-average price ($/MMBtu)	$ 2.65	$ 2.65	$ —

We earn a premium on our sold oil calls at the time of sale. We make net settlement payments for prices above the indicated weighted-average price per barrel of Brent. If the calls expire unexercised, we make no payments.

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. The purchased put options contain deferred premiums of approximately $20 million and are reflected in the mark-to-market valuation of the derivatives on the balance sheet at September 30, 2018. The premiums will be payable in conjunction with the monthly settlements of these contracts and thus have been deferred until payments begin in 2019.

For fixed-price Brent swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent.

For oil basis swaps, we make settlement payments if the difference between Brent and WTI is greater than the indicated weighted-average price per barrel of our contracts and receive settlement payments if the difference between Brent and WTI is below the indicated weighted-average price per barrel.

For fixed-price natural gas swaps, we are the buyer so we make settlement payments for prices below the weighted-average price per MMBtu and receive settlement payments for prices above the weighted-average price per MMBtu.

Our commodity derivatives are measured at fair value using industry-standard models with various inputs including forward prices, and all are classified as Level 2 in the required fair value hierarchy for the periods presented. The following tables present the fair values (gross and net) of our outstanding derivatives as of September 30, 2018 and December 31, 2017:

	Berry Corp. (Successor)			
	September 30, 2018			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Liabilities				
Commodity Contracts	Current liabilities	$ (26,409)	$ —	$ (26,409)
Commodity Contracts	Non-current liabilities	(4,664)	—	(4,664)
Total derivatives		$ (31,073)	$ —	$ (31,073)

	Berry Corp. (Successor)			
	December 31, 2017			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Liabilities				
Commodity Contracts	Current liabilities	$ (49,949)	$ —	$ (49,949)
Commodity Contracts	Non-current liabilities	(25,332)	—	(25,332)
Total derivatives		$ (75,281)	$ —	$ (75,281)

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

Note 5 - Lawsuits, Claims, Commitments and Contingencies

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

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

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

We have certain commitments under contracts, including purchase commitments for goods and services. At September 30, 2018, purchase obligations of approximately $10 million included a commitment to invest at least $9 million to construct a new access road in connection with our Piceance assets or provide access to an existing road or to pay 50% of the difference between $12 million and the actual amount spent on such access road construction prior to the end of 2019. If we do not obtain extensions for the road obligation, provide access to an existing road or construct a new access road, we may trigger the payment obligation which, if we were unable to negotiate resolution, would reduce our capital available for investment. Also, as of September 30, 2018, we had entered into agreements to purchase natural gas for our operations in 2018 for approximately $4 million.

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

We have entered into operating lease agreements mainly for office space. Lease payments are generally expensed as part of general and administrative expenses. At September 30, 2018, future net minimum lease payments for non-cancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes and insurance and maintenance expense) totaled:

		Amount (in thousands)
2018	$	362
2019		1,290
2020		316
2021		321
2022		326
Thereafter		229
Total minimum lease payments	$	2,844

Note 6 - Equity

Initial Public Offering of Common Stock

In July, we completed our IPO and as a result, on July 26, 2018, our common stock began trading on the NASDAQ Global Select Market under the ticker symbol BRY. The Company received approximately $111 million of net proceeds for the 8,695,653 shares of common stock issued for our benefit in the IPO, net of the shares sold for the benefit of the Company's stockholders. The shares sold to the public at $14.00 per share. The Company received the net proceeds from the IPO after deducting underwriting discounts and offering expenses payable by us, and the proceeds from the sale of the shares for the benefit of our stockholders. See "Use of IPO proceeds" below for additional information.

In connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock was automatically converted into 1.05 shares of our common stock or 39.6 million shares in aggregate and the right to receive a cash payment of $1.75 ("Series A Preferred Stock Conversion"). The cash payment was reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. The additional 1.9 million common shares received by the preferred stockholders in the conversion were assigned a value of $14.00 per share in the IPO. This approximate $27 million value and the $60 million conversion cash payment reduced the income available to common stockholders by approximately $87 million for the three months ended September 30, 2018.

Shares Issued and Outstanding

As of September 30, 2018, there were 81,364,933 shares of common stock issued and outstanding including 210,400 common shares outstanding as a result of awards that have vested as of September 30, 2018 under the Company's Omnibus Incentive Plan. An additional 1,396,000 unvested restricted stock units and performance restricted stock units were outstanding under the Company's Omnibus Incentive Plan as of September 30, 2018. A further 7,080,000 common shares have been reserved for issuance to the general unsecured creditor group pending resolution of disputed claims.

In March 2018, the board of directors approved a cumulative paid-in-kind dividend on the Series A Preferred Stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 per share and approximately 1,825,000 shares in total. Also in March 2018, the board approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018. In May 2018, the board of directors approved a $0.15 per share, or approximately $5.6 million cash dividend, on the Series A Preferred Stock for the quarter ended June 30, 2018. The payment was to stockholders of record as of June 7, 2018. As described above, in July 2018, all shares of our Series A Preferred Stock, approximately 37.7 million in total, were converted to approximately 39.6 million common shares and, as a result, there were no shares of our Series A Preferred Stock outstanding following the IPO.

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

Treasury Stock Purchase

In 2018, we entered into several settlement agreements with general unsecured creditors from our bankruptcy process. As a result, we paid approximately $20 million to purchase their claims to our common stock that we have reflected as treasury stock. The Plan required that we reserve 7,080,000 shares of our common stock to settle claims of unsecured creditors (the "Unsecured Claims"). We do not yet know the final amount of shares we will issue under these provisions. When all Unsecured Claims are settled, we will be able to assign a share count to the treasury stock. See Note 2 under *"Plan of Reorganization"* and Note 11 for further discussion of the common shares set aside to settle claims.

Stock-Based Compensation

In July 2018, we became a public company and our stock began trading on the NASDAQ Global Select Market. As a result, the fair value of our common stock underlying our stock-based compensation awards granted will no longer be based on complex models using inputs and assumptions, but will be based on the price of our stock at the date of grant.

On June 27, 2018, our board of directors adopted the Berry Petroleum Corporation 2017 Omnibus Incentive Plan, as amended and restated (our “Restated Incentive Plan”). This plan constitutes an amendment and restatement of the plan (the "Prior Plan") as in effect immediately prior to the adoption of the Restated Incentive Plan. The Prior Plan constituted an amendment and restatement of the plan originally adopted as of June 15, 2017 (the "2017 Plan"). The Restated Incentive Plan provides for the grant, from time to time, at the discretion of the board of directors or a committee thereof, of stock options, stock appreciation rights ("SARs"), restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards and substitute awards. The maximum number of shares of common stock that may be issued pursuant to an award under the Restated Incentive Plan is 10,000,000 inclusive of the number of shares of common stock previously issued pursuant to awards granted under the Prior Plan or the 2017 Plan. The maximum number of shares remaining that may be issued is approximately 8.4 million as of September 30, 2018.

Included in lease operating expenses and general and administrative expenses is stock-based compensation expense of $0.1 million and $1.1 million, respectively, for the three months ended September 30, 2018, and $0.1 million and $3.4 million, respectively, for the nine months ended September 30, 2018. For the three and nine months ended September 30, 2017, including the successor and predecessor periods, stock compensation expense included in lease operating expenses and general and administrative expenses was none and $0.9 million, respectively. For the nine months ended September 30, 2018, stock-based compensation had an income tax benefit of approximately $0.6 million.

The table below summarizes the activity relating to restricted stock units ("RSUs") issued under the 2017 Plan during the nine months ended September 30, 2018. The RSUs vest ratably over three years. Unrecognized compensation cost associated with the RSUs at September 30, 2018 is approximately $6.2 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares	Weighted-average Grant Date Fair Value
	(shares in thousands)	
December 31, 2017	683	$ 10.12
Granted	217	$ 11.81
Vested	(210)	$ 10.12
Forfeited	(32)	$ 10.35
September 30, 2018	658	$ 10.67

The table below summarizes the activity relating to the performance-based restricted stock units ("PRSUs") issued under the 2017 Plan during the nine months ended September 30, 2018. The PRSUs vest if the Company's stock price reaches certain levels over defined periods of time. Unrecognized compensation cost associated with the PRSUs at September 30, 2018 is approximately $3.4 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares	Weighted-average Grant Date Fair Value
	(shares in thousands)	
December 31, 2017	622	$ 7.09
Granted	132	$ 7.65
Vested	—	$ —
Forfeited	(16)	$ 7.25
September 30, 2018	738	$ 7.19

In October 2018, approximately 454,000 PRSUs under the Restated Incentive Plan vested.

Use of IPO Proceeds

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

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

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

Note 7 - Income Taxes

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

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

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

Note 8 - Supplemental Disclosures to the Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Cash Flows

Other current assets reported on the condensed consolidated balance sheets included the following:

	Berry Corp. (Successor)	
	September 30, 2018	**December 31, 2017**
	(in thousands)	
Prepaid expenses	$ 4,945	$ 6,901
Oil inventories, materials and supplies	7,060	5,938
Other	1,228	1,227
Total	$ 13,233	$ 14,066

The major classes of inventory were not material and therefore not stated separately. Other non-current assets at September 30, 2018 and December 31, 2017, included approximately $17 million and $20 million of deferred financing costs, net of amortization, respectively.

Accounts payable and accrued expenses on the condensed consolidated balance sheets included the following:

	Berry Corp. (Successor)	
	September 30, 2018	December 31, 2017
	(in thousands)	
Accounts payable-trade	$ 10,483	$ 15,469
Accrued expenses	54,969	34,359
Royalties payable	26,004	25,793
Greenhouse gas liability	4,364	10,446
Taxes other than income tax liability	11,021	8,437
Accrued interest	3,529	—
Dividends payable	7,431	—
Other	—	3,373
Total	$ 117,801	$ 97,877

Other non-current liabilities at September 30, 2018 included approximately $12 million of greenhouse gas liability.

Supplemental Cash Flow Information

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)		
Supplemental Disclosures of Significant Non-Cash Investing Activities:			
(Decrease) increase in accrued liabilities related to purchases of property and equipment	$ 8,832	$ 1,008	$ 2,249
Supplemental Disclosures of Cash Payments/(Receipts):			
Interest	$ 19,199	$ 9,987	$ 8,057
Income taxes	$ —	$ 1,994	$ —
Reorganization items, net	$ 1,007	$ (375)	$ 11,838

The following table provides a reconciliation of Cash, Cash Equivalents and Restricted Cash as reported in the Consolidated Statements of Cash Flows to the line items within the Consolidated Balance Sheets:

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine months ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
		(in thousands)	
Beginning of Period			
Cash and cash equivalents	$ 33,905	$ 32,049	$ 30,483
Restricted cash	34,833	52,860	197,793
Restricted cash in other noncurrent assets	—	125	128
Cash, cash equivalents and restricted cash	$ 68,738	$ 85,034	$ 228,404
Ending of Period			
Cash and cash equivalents	$ 23,856	$ 2,927	$ 32,049
Restricted cash	57	35,000	52,860
Restricted cash in other noncurrent assets	—	—	125
Cash, cash equivalents and restricted cash	$ 23,913	$ 37,927	$ 85,034

Restricted cash is associated with cash reserved to settle claims with general unsecured creditors resulting from implementation of the Plan. Cash and cash equivalents consists primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value.

Note 9 - Certain Relationships and Related Party Transactions

In connection with our emergence from bankruptcy, we entered into agreements with certain of our affiliates and with parties who received shares of our common stock and Series A Preferred Stock in exchange for their claims. See Note 6 - Equity for further details.

Transition Services and Separation Agreement (“TSSA”)

On the Effective Date, Berry LLC entered into the TSSA with Linn Energy and certain of its subsidiaries to facilitate the separation of Berry LLC’s operations from Linn Energy’s operations. Under the TSSA, Berry LLC reimbursed Linn Energy for third-party out-of-pocket costs and expenses actually incurred by Linn Energy in connection with providing certain transition services. Additionally, Berry LLC paid to Linn Energy a management fee equal to $6 million per month, prorated for partial months, during the period from the Effective Date through the last day of the second full calendar month after the Effective Date (the “Transition Period”) and $2.7 million per month, prorated for partial months, from the first day following the Transition Period through the last day of the second full calendar month thereafter (the “Accounting Period”). During the Accounting Period, the scope of the transition services was reduced to specified accounting and administrative services. The Transition Period under the TSSA ended April 30, 2017, and the Accounting Period ended June 30, 2017. For the seven months ended September 30, 2017, we incurred management fee expenses of approximately $17 million under the TSSA. Since the agreement commenced on the Effective Date, no expenses were incurred for the period ended February 28, 2017.

Note 10 - Acquisitions and Divestitures

Chevron North Midway-Sunset Acquisition

In April 2018, we acquired two leases from a third party on an aggregate of 214 acres and a lease option on 490 acres (the "Chevron North Midway-Sunset Acquisition") of land owned by Chevron U.S.A. in the north Midway-Sunset field immediately adjacent to assets we currently operate. We assumed a drilling commitment of approximately $34.5 million to drill 115 wells on or before April 1, 2020. We have not drilled any of these wells as of September 30, 2018. We extended the commitment to April

1, 2022. We would assume an additional 40 well drilling commitment if we exercise our option on the 490 acres. We paid no other consideration for the acquisition. Our drilling commitment will be tolled for a month for each consecutive 30-day period for which the posted price of WTI is less than $45 per barrel. This transaction is consistent with our business strategy to investigate areas beyond our known productive areas.

Disposition of East Texas Properties

On October 17, 2018, we signed an agreement to sell our non-core oil and gas properties and related assets located in the East Texas Basin for approximately $7 million. Production comprised approximately 0.7 MBoe per day of natural gas in the third quarter of 2018. We anticipate closing this sale in the fourth quarter of 2018.

Note 11 - Earnings Per Share

The Predecessor was organized as a limited liability company and, as such, did not issue any stock. Accordingly, we have not presented earnings per share calculations for the predecessor company periods.

We calculate basic earnings (loss) per share by dividing net income (loss) available to common stockholders by the weighted-average number of common shares outstanding during each period. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, such as those shares contemplated by the Plan, are considered common shares outstanding and are included in the computation of net income (loss) per share. Accordingly, the 40 million shares of common stock contemplated by the Plan, without regard to actual issuance dates, were included in the computation of net income (loss) per share for the three and nine months ended September 30, 2018, and the three and seven months ended September 30, 2017. The Plan required that we reserve 7,080,000 shares of our common stock to settle claims of unsecured creditors. The final amount of shares we will issue under these provisions cannot be known until all claims are settled, adjustments have been made based on the stock to be received by Unsecured Claims including those of holders of Unsecured Notes. However, while we do not yet know the final amount of shares that we will issue to third parties, we entered into agreements in 2018 that have materially reduced that number. The 40 million shares above will be reduced to the extent we issue fewer than 7,080,000 shares.

The Series A Preferred Stock was not a participating security, therefore, we calculated diluted EPS using the “if-converted" method under which the preferred dividends are added back to the numerator and the convertible preferred stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock or RSUs were included in the diluted EPS calculation for the three and nine months ended September 30, 2018, nor the three months ended September 30, 2017 as their effect was anti-dilutive under the “if-converted” method. No PRSU's were included in the EPS calculations for any of the periods presented due to their contingent nature.

In July 2018, all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO of our common stock (see Note 6). The conversion was characterized as an induced conversion that required a deduction in our EPS calculation, from net income, of approximately $87 million in determining income available to common stockholders. This deduction represents the excess of fair value of the total consideration given to preferred stockholders in the transaction over the fair value of the common stock issuable under the original conversion terms. Included in the $87 million is a $60 million cash payment and approximately $27 million of value from the 1.9 million additional common shares received by preferred stockholders as a result of the automatic conversion that occurred in conjunction with our IPO.

	Berry Corp. (Successor)				Berry LLC (Predecessor)
	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands except per share amounts)				
Basic EPS calculation					
Net income (loss)	$ 36,985	$ (9,684)	$ 15,334	13,812	n/a
less: Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(97,942)	(12,681)	n/a
Net income (loss) available to common stockholders	$ (49,657)	$ (15,169)	$ (82,608)	$ 1,131	n/a
Weighted-average shares of common stock outstanding	68,131	32,920	44,820	32,920	n/a
Shares of common stock distributable to holders of Unsecured Claims	7,080	7,080	7,080	7,080	n/a
Weighted-average common shares outstanding-basic	75,211	40,000	51,900	40,000	n/a
Basic Earnings (loss) per share [(2)]	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a
Diluted EPS calculation					
Net income (loss)	$ 36,985	$ (9,684)	$ 15,334	$ 13,812	n/a
less: Series A preferred stock dividends and conversion to common stock	(86,642)	(5,485)	(97,942)	(12,681)	n/a
Net income (loss) available to common stockholders	$ (49,657)	$ (15,169)	$ (82,608)	$ 1,131	n/a
Weighted-average shares of common stock outstanding	68,131	32,920	44,820	32,920	n/a
Shares of common stock distributable to holders of Unsecured Claims	7,080	7,080	7,080	7,080	n/a
Weighted-average common shares outstanding-basic	75,211	40,000	51,900	40,000	n/a
Dilutive effect of potentially dilutive securities [(1)]	$ —	$ —	$ —	$ 602	n/a
Weighted-average common shares outstanding-diluted	75,211	40,000	51,900	40,602	n/a
Diluted Earnings (loss) per share [(2)]	$ (0.66)	$ (0.38)	$ (1.59)	$ 0.03	n/a

(1) No potentially dilutive securities were included in computing earnings (loss) per share for the three and nine months ended September 30, 2018 and for the three months ended September 30, 2017 because the effect of inclusion would have been anti-dilutive.

(2) Per share amounts are stated net of tax.

Item 2.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes presented in this Quarterly Report on form 10-Q, as well as our audited consolidated financial statements for the year ended December 31, 2017 included in the prospectus. When we use the terms "we," "us," "our," the "Company" or similar words, unless the context otherwise requires, on or prior to the Effective Date (see below), we are referring to Berry LLC, our predecessor company and following February 28, 2017, the effective date ("Effective Date") of the Amended Joint Chapter 11 Plan of Linn Acquisition Company, LLC and us, we are referring to Berry Corp. and its subsidiary, Berry LLC, together, the successor company, as applicable.

Our Company

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

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

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

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

In California, we focus on conventional, shallow reservoirs, the drilling and completion of which are relatively low-cost in contrast to modern unconventional resource plays. Our decades-old proven completion techniques in these reservoirs include steamflood and low-volume fracture stimulation.

We own additional assets in the Uinta basin in Utah, a stacked, multi-bench, light-oil-prone play with significant undeveloped resources where we have high operational control and additional behind pipe potential, as well as in the Piceance basin in Colorado, a prolific low geologic risk natural gas play where we produce from a conventional, tight sandstone reservoir using proven slick water fracture stimulation techniques to increase recoveries.

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

How We Plan and Evaluate Operations

We use levered free cash flow to plan our capital allocation for maintenance and internal growth opportunities as well as hedging needs. We define levered free cash flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

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

Adjusted EBITDA

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

Operating expenses

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

Environmental, health & safety

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

Taxes, other than income taxes

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

General and administrative expenses

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

Production

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

Emergence from Chapter 11 Bankruptcy

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

Non-GAAP Financial Measures

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

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

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

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

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

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

Adjusted General and Administrative Expenses

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

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

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

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

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

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

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

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

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

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

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

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

Basis of Presentation and Fresh-Start Accounting

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

Unless otherwise noted or suggested by context, all financial information and data and accompanying financial statements and corresponding notes, as contained in this Quarterly Report on Form 10-Q, on or prior to the Effective Date, reflect the actual historical results of operations and financial condition of our predecessor company for the periods presented and do not give effect to the Plan or any of the transactions contemplated thereby or the adoption of fresh-start accounting. Following the Effective Date, they reflect the actual historical results of operations and financial condition of Berry Corp. on a consolidated basis and give effect to the Plan and any of the transactions contemplated thereby and the adoption of fresh-start accounting. Thus, the financial information presented herein on or prior to the Effective Date is not comparable to Berry Corp.'s performance or financial condition after the Effective Date. As a result, "black-line" financial statements are presented to distinguish between Berry LLC as the predecessor and Berry Corp. as the successor.

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

The main actions we took affecting comparability between periods presented include the reorganization of Berry LLC through bankruptcy, entry into the RBL Facility, issuance of the 2026 Notes, dividends on and conversion of Series A Preferred Stock and completion of the IPO. These actions are described above under "Emergence from Chapter 11 Bankruptcy" and below in "Liquidity and Capital Resources."

Capital Expenditures

For the three and nine months ended September 30, 2018, our capital expenditures were approximately $40 million and $95 million, respectively, on an accrual basis excluding acquisitions.

Following Berry LLC's emergence from bankruptcy and separation from the Linn Entities, we increased our pace of development and have continued to do so in 2018. Our 2018 anticipated capital expenditure budget of approximately $140 to $160 million represents an increase of approximately 107% over our 2017 capital expenditures, including the successor and predecessor periods, of approximately $73 million. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2018 capital program exclusively with our levered free cash flow. We expect to:

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

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

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

2019 Guidance

The table below sets forth our 2019 Guidance for certain metrics.

	2019 Guidance	
	Low	High
Average daily production (MBoe/d)	29	32
% Oil	~86%	
Operating expenses ($/Boe)	$17.00	$18.50
Taxes, other than income taxes ($/Boe)	$4.25	$4.75
Adjusted General & Administrative Expenses ($/Boe)	$4.00	$4.50
Capital Expenditures ($mm)	$230	$260

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGLs, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and materially affect our business, financial condition and results of operations.

Chevron North Midway-Sunset Acquisition

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

Disposition of East Texas Properties

On October 17, 2018, we signed an agreement to sell our non-core oil and gas properties and related assets located in the East Texas Basin for approximately $7 million. Production comprised approximately 0.7 MBoe per day of natural gas in the third quarter of 2018. We anticipate closing this sale in the fourth quarter of 2018.

Commodity Derivatives

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

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

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

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

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

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

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

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

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

Income Taxes

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

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

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

Business Environment and Market Conditions

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

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

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

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

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

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

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

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

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

Seasonality

Seasonal weather conditions can impact a portion of our drilling and production activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires.

Natural gas prices can fluctuate based on seasonal impacts. We purchase gas, significantly more than we sell, to generate steam in our cogeneration facilities for our producing activities. As a result, our key exposure to gas prices is in our costs. We effectively mitigate this exposure by selling excess electricity from our cogeneration operations to third parties. The prices of these electricity sales are closely tied to the purchase price of natural gas.

Production, Prices and Costs

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

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

(1) Production represents volumes sold during the period.

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

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

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

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

	Berry Corp. (Successor)		
	Three Months Ended		
	September 30, 2018	June 30, 2018	September 30, 2017
Average daily production (MBoe/d)[(1)]:			
California (San Joaquin)[(2)]	19.5	18.8	18.8
Hugoton basin[(3)]	—	—	3.2
Uinta basin	5.1	5.3	5.0
Piceance basin	2.0	1.6	1.1
East Texas	0.7	0.8	1.1
Total average daily production	27.4	26.5	29.2

(1) Production represents volumes sold during the period.

(2) On July 31, 2017, we purchased the remaining approximately 84% working interest of our South Belridge Hill property, located in Kern County, California.

(3) On July 31, 2017, we sold our 78% working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle. Our Hugoton assets represented approximately 24% of our average net daily production for the year ended December 31, 2016.

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

Average daily production volumes decreased 6% to approximately 27.4 MBoe/d for the three months ended September 30, 2018 from approximately 29.2 MBoe/d for the three months ended September 30, 2017. The decrease primarily reflected the decreased natural gas and NGL volumes from the sale of an approximately 78% non-operating, working interest in the Hugoton natural gas field (the "Hugoton Disposition") in July 2017, partially offset by the additional oil volumes from the acquisition of an approximately 84% non-operating, working interest in a South Belridge Hill property, (the "Hill Acquisition") in July 2017. Partially offsetting this overall Boe decrease was an increase in oil production, mainly in California, as a result of our increased capital spending and development program in 2018 compared to 2017, and to a lesser degree, the sales of oil inventory in the quarter ended September 30, 2018. The Hill Acquisition and Hugoton Disposition resulted in an increase in oil production to 81% of total production in the three months ended September 30, 2018 from 73% of total production for the three months ended September 30, 2017.

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

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

(1) Production represents volumes sold during the period.

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

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

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
Average daily production (MBoe/d)[1]:			
California (San Joaquin)[2]	19.0	17.3	17.0
Hugoton basin[3]	—	6.5	10.8
Uinta basin	5.2	5.4	5.4
Piceance basin	1.7	1.9	2.4
East Texas	0.8	1.0	1.1
Total average daily production	26.7	32.1	36.7

(1) Production represents volumes sold during the period.

(2) On July 31, 2017, we purchased the remaining approximately 84% working interest of our South Belridge Hill property, located in Kern County, California.

(3) On July 31, 2017, we sold our 78% working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle. Our Hugoton assets represented approximately 24% of our average net daily production for the year ended December 31, 2016.

Average daily production volumes decreased to approximately 26.7 MBoe/d for the nine months ended September 30, 2018 from approximately 33.1 MBoe/d for the nine months ended September 30, 2017, including the successor and predecessor periods. The decrease primarily reflected the decreased natural gas and NGL volumes from the sale of the approximately 78% non-operating, working interest in the Hugoton natural gas field in July 2017, partially offset by the additional oil volumes from the Hill Acquisition. Partially offsetting the overall Boe decrease was an increase in oil production, mainly in California, as a result of our increased capital spending and development program in 2018 compared to 2017. The Hill Acquisition and Hugoton Disposition resulted in an increase in oil production to 81% of total production for the nine months ended September 30, 2018 from 60% for the nine months ended September 30, 2017.

Balance Sheet Analysis

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

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

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

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

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

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

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

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

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

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

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

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

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

Results of Operations

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

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

Revenues and Other

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

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

Losses on oil and natural gas derivatives were approximately $19 million for the three months ended September 30, 2018 compared to losses of approximately $78 million for the three months ended June 30, 2018. The improvement reflects the May

2018 transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with market pricing at the time.

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

Expenses and other

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

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

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

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

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

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

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

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

Taxes, Other Than Income Taxes

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

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

Other income (expenses)

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

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

Reorganization items

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

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

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

Income taxes

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

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

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

Revenues and Other

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

Electricity sales represent sales to utilities and increased by approximately $5 million, or 60%, to approximately $14 million for the three months ended September 30, 2018 compared to the three months ended September 30, 2017. The increase was primarily due to higher fuel prices in the three months ended September 30, 2018 than the three months ended September 30, 2017.

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

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

Expenses and Other

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

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

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

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

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

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

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

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

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

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

Taxes, Other Than Income Taxes

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

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

Other income (expenses)

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

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

Reorganization items

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

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

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

Income taxes

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

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

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

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

Revenues and Other

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

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

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

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

Expenses and other

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

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

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

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

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

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

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

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

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

Taxes, Other Than Income Taxes

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

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

Other income (expenses)

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

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

Reorganization items

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

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

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

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

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

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

Liquidity and Capital Resources

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

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

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

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

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

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

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

In connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock was automatically converted into 1.05 shares of our common stock or 39.6 million shares in aggregate and the right to receive a cash payment of $1.75 ("Series A Preferred Stock Conversion"). The cash payment was reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. The additional 1.9 million common shares received by the preferred stockholders in the conversion were assigned a value of $14.00 per share in the IPO. This approximate $27 million value and the $60 million conversion cash payment reduced the income available to common stockholders by approximately $87 million for the three months ended September 30, 2018.

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

The RBL Facility contains certain financial covenants, including the maintenance of (i) a Leverage Ratio (as defined in the RBL Facility) not to exceed 4.00:1.00 and (ii) a Current Ratio (as defined in the RBL Facility) not to be less than 1.00:1.00. As of September 30, 2018, our Leverage Ratio and Current Ratio were 1.85:1.00 and 4.21:1.00, respectively. As of September 30, 2018 our borrowing base was approximately $400 million and we had $393 million available for borrowing under the RBL Facility. At September 30, 2018, we were in compliance with the financial covenants under the RBL Facility. In connection with the issuance of the 2026 Notes, the RBL Facility borrowing base was set at $400 million, which incorporated a $100 million reduction, or 25%, of the face value of the 2026 Notes. In March 2018, we completed a borrowing base redetermination that reaffirmed our borrowing base at $400 million with an elected commitment feature that allows us to increase the borrowing base to $575 million with lender approval. Borrowing base redeterminations become effective on, or about, each May 1 and November 1, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations.

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

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

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

See "Capital Expenditures and Capital Budget" for a description of our 2018 capital expenditure budget.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)		
Net cash:			
Provided by (used in) operating activities	$ 7,334	$ 70,505	$ 22,431
Used in investing activities	(82,375)	(74,563)	(3,133)
Provided by (used in) financing activities	30,216	(43,049)	(162,668)
Net decrease in cash, cash equivalents and restricted cash	$ (44,825)	$ (47,107)	$ (143,370)

Operating Activities

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

Investing Activities

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Nine Months Ended September 30, 2018	Seven Months Ended September 30, 2017	Two Months Ended February 28, 2017
	(in thousands)		
Capital expenditures (1)			
Development of oil and natural gas properties	(74,447)	(38,445)	(859)
Purchase of other property and equipment	(11,305)	(11,497)	(2,299)
Proceeds from sale of properties and equipment and other	3,377	234,823	25
Acquisition of properties	—	(259,444)	—
Cash used in investing activities:	$ (82,375)	$ (74,563)	$ (3,133)

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

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

Financing Activities

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

Debt

2026 Notes Offering

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

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

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

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

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

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

The RBL Facility

On July 31, 2017, Berry LLC, as borrower, entered into the RBL Facility. The RBL Facility provides for a revolving loan with up to $1.5 billion of commitments, subject to a reserve borrowing base, and provided an initial commitment of $500 million. The RBL Facility also provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. Borrowing base redeterminations become effective on or about each May 1 and November 1, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. In connection with the issuance of the 2026 Notes, the RBL Facility borrowing base was set at $400 million, which incorporated a $100 million reduction, or 25%, of the face value of the 2026 Notes. In March 2018, we completed a borrowing base redetermination that reaffirmed our borrowing base at $400 million with an elected commitment feature that allows us to increase the borrowing base to $575 million with lender approval. As of September 30, 2018, we had approximately $7 million in letters of credit outstanding and borrowing availability of $393 million under the RBL Facility. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

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

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

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

- incur or guarantee additional indebtedness;
- transfer, sell or dispose of assets;
- make loans to others;
- make investments;
- merge with another entity;
- make or declare dividends;
- hedge future production or interest rates;
- enter into transactions with affiliates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

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

Lawsuits, Claims, Commitments, and Contingencies

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

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

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at September 30, 2018 and December 31, 2017. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters.

We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

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

Contractual Obligations

During the nine months ended September 30, 2018, there were no significant changes in our consolidated contractual obligations from those reported in the prospectus.

Recently Adopted Accounting and Disclosure Changes

See Note 1, Accounting and Disclosure Changes, in the Notes to Consolidated Condensed Financial Statements in Part I, Item 1 of this Form 10-Q.

Safe Harbor Statement Regarding Outlook and Forward-Looking Information

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

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

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

- concerns about climate change and other air quality issues;
- catastrophic events;
- litigation;
- our ability to retain key members of our senior management and key technical employees;
- information technology failures or cyber attacks.

We undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three months ended September 30, 2018, there were no material changes in the information required to be provided under Item 305 of Regulation S-K included under the caption *Management's Discussion and Analysis of Financial Condition and Results of Operations (Incorporating Item 7A)-Quantitative and Qualitative Disclosures About Market Risk*, in the prospectus.

Price Risk

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

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

Counterparty Credit Risk

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

Interest Rate Risk

Our RBL Facility has a variable interest rate on outstanding balances. As of September 30, 2018, there were no borrowings under our RBL Facility and thus we were not exposed to interest rate risk on this facility. See Note 3 for additional information regarding interest rates on outstanding debt. The 2026 Notes have a fixed interest rate and thus we are not exposed to interest rate risk on these.

Item 4. Controls and Procedures

Our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer supervised and participated in our evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2018.

Part II – Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 5 to the consolidated financial statements in Part I of this Form 10-Q and Note 7 to our consolidated financial statements for the year ended December 31, 2017 included in the prospectus.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. A discussion of such risks and uncertainties may be found under the heading Risk Factors in the prospectus.

Item 2. Unregistered Sales of Equity Securities

Series A Preferred Stock

In July 2018, in connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock was automatically converted into 1.05 shares of our common stock or 39.6 million shares in aggregate and the right to receive a cash payment of $1.75. The cash payment was reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. As a result, there were no shares of our Series A Preferred Stock outstanding following the IPO.

Item 5. Other Disclosures

Annual Meeting of Stockholders

The Company's board of directors (the "Board") has determined that it intends to hold the Company's Annual Meeting of Stockholders (the "2019 Annual Meeting") on May 14, 2019, at a time and location to be specified in the Company's proxy statement for the 2019 Annual Meeting (the "Proxy Statement"). The record date for determining stockholders eligible for notice of, and to vote at, the 2019 Annual Meeting will be March 18, 2019.

Because the 2019 Annual Meeting will be the Company's first annual meeting as a public company, pursuant to Rule 14a-8 ("Rule 14a-8") under the Exchange Act, stockholders of the Company who wish to have a proposal considered for inclusion in the Company's proxy materials for the 2019 Annual Meeting pursuant to Rule 14a-8 must ensure that their proposal is received by the Secretary of the Company at 16000 North Dallas Parkway, Suite 500, Dallas, Texas by December 8, 2018, which the Company has determined to be a reasonable time before it expects to begin to print and send its proxy materials. Rule 14a-8 proposals must also comply with the requirements of Rule 14a-8 and other applicable laws in order to be eligible for inclusion in the Company's proxy materials for the 2019 Annual Meeting. The December 8, 2018 deadline will also apply in determining whether notice of a stockholder proposal is timely for purposes of exercising discretionary voting authority with respect to proxies under Rule 14a-4(c) under the Exchange Act.

In addition, in accordance with the requirements contained in the Company's Amended and Restated Bylaws (the "Bylaws"), stockholders who wish to bring business before the 2019 Annual Meeting outside of Rule 14a-8 or to nominate a person for election as a director must ensure that written notice of such proposal (including all of the information specified in the Bylaws) is received by the Secretary of the Company at the address specified above no later than the close of business on November 18, 2018. Any such proposal must meet the requirements set forth in the Bylaws in order to be brought before the 2019 Annual Meeting.

Item 6. Exhibits

Exhibit Number	Description
10.1	Stock Purchase Agreement by and between Berry Petroleum Corporation, Oaktree Value Opportunities Fund Holdings, L.P. and Oaktree Opportunities X Fund Holdings (Delaware), L.P. dated July 17, 2018 (incorporated by reference to Exhibit 10.2 of Form 8-K filed July 30, 2018)
10.2	Stock Purchase Agreement by and between Berry Petroleum Corporation and certain funds affiliated with Benefit Street Partners named in Schedule I thereto, dated July 17, 2018 (incorporated by reference to Exhibit 10.3 of Form 8-K filed July 30, 2018)
10.3	Amended and Restated Employment Agreement, Arthur T. Smith dated August 22, 2018 (incorporated by reference to Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, filed August 23, 2018)
10.4	Amended and Restated Employment Agreement, Cary D. Baetz dated August 22, 2018 (incorporated by reference to Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, filed August 23, 2018)
10.5	Amended and Restated Employment Agreement, Gary A. Grove dated August 22, 2018 (incorporated by reference to Exhibit 10.16 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, filed August 23, 2018)
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 and Chief Financial Officer

* Filed herewith.

** Furnished herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms that may be used in this report, which are commonly used in the oil and natural gas industry:

"*API*" gravity means the relative density, expressed in degrees, of petroleum liquids based on a specific gravity scale developed by the American Petroleum Institute.

"*basin*" means a large area with a relatively thick accumulation of sedimentary rocks.

"*Bbl*" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"*Bcf*" means one billion cubic feet, which is a unit of measurement of volume for natural gas.

"*Boe*" means barrel of oil equivalent, determined using the ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas.

"*Boe/d*" means Boe per day.

"*Brent*" means the reference price paid in U.S. dollars for a barrel of light sweet crude oil produced from the Brent field in the UK sector of the North Sea.

"*Btu*" means one British thermal unit-a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"*Completion*" means the installation of permanent equipment for the production of oil or natural gas.

"*Condensate*" means a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"*Development drilling or Development well*" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"*Diatomite*" means a sedimentary rock composed primarily of siliceous, diatom shells.

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

"*Downspacing*" means additional wells drilled between known producing wells to better develop the reservoir.

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

"*EOR*" means enhanced oil recovery.

"*Estimated ultimate recovery*" or "*EUR*" means the sum of reserves remaining as of a given date and cumulative production as of that date. EUR is shown on a combined basis for oil and natural gas.

"*Exploration activities*" means the initial phase of oil and natural gas operations that includes the generation of a prospect or play and the drilling of an exploration well.

"*Field*" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

"*Formation*" means a layer of rock which has distinct characteristics that differ from those of nearby rock.

"*Fracturing*" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks by connecting pores together.

"*Gas*" or "*Natural gas*" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"*Gross Acres*" or "*Gross Wells*" means the total acres or wells, as the case may be, in which we have a working interest.

"*Held by production*" means acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.

"*Henry Hub*" is a distribution hub on the natural gas pipeline system in Erath, Louisiana.

"*Hydraulic fracturing*" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability.

"*Horizontal drilling*" means a wellbore that is drilled laterally.

"*ICE*" means Intercontinental Exchange.

"*Infill drilling*" means drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.

"*Injection Well*" means a well in which water, gas or steam is injected, the primary objective typically being to maintain reservoir pressure and/or improve hydrocarbon recovery.

"*IOR*" means improved oil recovery.

"*Leases*" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"*MBbl*" means one thousand barrels of oil, condensate or NGLs.

"*MBoe*" means one thousand barrels of oil equivalent.

"*MBoe/d*" means MBoe per day.

"*Mcf*" means one thousand cubic feet, which is a unit of measurement of volume for natural gas.

"*MMBbl*" means one million barrels of oil, condensate or NGLs.

"*MMBoe*" means one million barrels of oil equivalent.

"*MMBtu*" means one million Btus.

"*MMcf*" means one million cubic feet, which is a unit of measurement of volume for natural gas.

"*MMcf/d*" means MMcf per day.

"*MW*" means megawatt.

"*Net Acres*" or "*Net Wells*" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"*Net revenue interest*" means all of the working interests, less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"*NGL*" means natural gas liquids, which are the hydrocarbon liquids contained within natural gas.

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

"*Operator*" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"*PDNP*" is an abbreviation for proved developed non-producing.

"*PDP*" is an abbreviation for proved developed producing.

"*Permeability*" means the ability, or measurement of a rock's ability, to transmit fluids.

"*Play*" means a regionally distributed oil and natural gas accumulation. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations.

"*Porosity*" means the total pore volume per unit volume of rock.

"*PPA*" is an abbreviation for power purchase agreement.

"*Production costs*" means costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).

"*Productive well*" means a well that is producing oil, natural gas or NGLs or that is capable of production.

"*Proppant*" means sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.

"*Prospect*" means a specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

"*Proved developed reserves*" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved developed producing reserves*" means reserves that are being recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*" means the estimated quantities of oil, gas and gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"*Proved undeveloped drilling location*" means a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*" means proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"*PV-10*" is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC-prescribed pricing assumptions for the period. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the company on a comparative basis to other companies and from period to period.

"*Realized price*" means the cash market price less all expected quality, transportation and demand adjustments.

"*Reasonable certainty*" means a high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

"*Recompletion*" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

"*Reserves*" means estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

"*Resources*" means quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

"*Royalty*" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"*Royalty interest*" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"*SEC Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules based on the unweighted arithmetic average of oil and natural gas prices as of the first day of each of the 12 months ended on the given date.

"*Seismic Data*" means data produced by an exploration method of sending energy waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

"*Spacing*" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Steamflood*" means cyclic or continuous steam injection.

"*Standardized measure*" means discounted future net cash flows estimated by applying year-end prices to the estimated future production of proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Strip Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules with the exception of pricing that is based on average annual forward-month ICE (Brent) oil and NYMEX Henry Hub natural gas contract pricing in effect on a given date to reflect the market expectations as of that date.

"*Undeveloped acreage*" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

"*Unit*" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Unproved reserves*" means reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

"*Wellbore*" means the hole drilled by the bit that is equipped for natural resource production on a completed well. Also called well or borehole.

"*Working interest*" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"*Workover*" means maintenance on a producing well to restore or increase production.

"*WTI*" means West Texas Intermediate.

SIGNATURES

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

		BERRY PETROLEUM CORPORATION
		(Registrant)
Date:	November 8, 2018	*/s/ Cary Baetz*
		Cary Baetz
		Executive Vice President and Chief Financial Officer
		(Principal Financial Officer)
Date:	November 8, 2018	*/s/ Michael S. Helm*
		Michael S. Helm
		Chief Accounting Officer
		(Duly Authorized Officer and Principal Accounting Officer)

EXHIBIT 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Arthur T. Smith, certify that:

1. I have reviewed this quarterly report of Berry Petroleum Corporation (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 8, 2018	*/s/ Arthur T. Smith*
	Arthur T. Smith
	President and Chief Executive Officer (Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Cary Baetz, certify that:

1. I have reviewed this quarterly report of Berry Petroleum Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2018	*/s/ Cary Baetz*
	Cary Baetz
	Executive Vice President and Chief Financial Officer
	(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO
PURSUANT TO SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the quarterly report of Berry Petroleum Corporation (the “Company”) for the fiscal period ended September 30, 2018, as filed with the Securities and Exchange Commission on November 8, 2018 (the “Report”), Arthur T. Smith, as Chief Executive Officer of the Company, and Cary Baetz, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge, respectively:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 8, 2018

/s/ Arthur T. Smith
Arthur T. Smith
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Cary Baetz
Cary Baetz
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

A signed original of this written statement required by Section 906 has been provided to Berry Petroleum Corporation and will be retained by Berry Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

The certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.