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, 2019

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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, par value $0.001 per share	BRY	Nasdaq Global Select Market

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, 2019 80,997,405

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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)

	September 30, 2019	December 31, 2018
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ —	$ 68,680
Accounts receivable, net of allowance for doubtful accounts of $1,377 at September 30, 2019 and $950 at December 31, 2018	63,673	57,379
Derivative instruments	50,029	88,596
Other current assets	16,335	14,367
Total current assets	130,037	229,022
Noncurrent assets:		
Oil and natural gas properties	1,685,269	1,461,993
Accumulated depletion and amortization	(186,578)	(123,217)
Total oil and natural gas properties, net	1,498,691	1,338,776
Other property and equipment	132,066	119,710
Accumulated depreciation	(22,947)	(15,778)
Total other property and equipment, net	109,119	103,932
Derivative instruments	13,663	3,289
Other non-current assets	14,068	17,244
Total assets	$ 1,765,578	$ 1,692,263
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 145,360	$ 144,118
Derivative instruments	3,534	—
Total current liabilities	148,894	144,118
Noncurrent liabilities:		
Long-term debt	402,290	391,786
Deferred income taxes	65,129	45,835
Asset retirement obligation	122,733	89,176
Other noncurrent liabilities	29,188	14,902
Commitments and Contingencies - Note 4		
Equity:		
Common stock ($.001 par value; 750,000,000 shares authorized; and 80,997,405 and 81,202,437 shares outstanding, at September 30, 2019 and December 31, 2018, respectively)	85	82
Additional paid-in-capital	899,421	914,540
Treasury stock, at cost, (3,648,823 shares at September 30, 2019 and 448,661 shares at December 31, 2018)	(39,225)	(24,218)
Retained earnings	137,063	116,042
Total equity	997,344	1,006,446
Total liabilities and equity	$ 1,765,578	$ 1,692,263

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 141,250	$ 147,004	$ 409,259	$ 410,013
Electricity sales	7,460	14,268	22,553	25,691
Gains (losses) on oil derivatives	45,509	(18,994)	7,546	(131,781)
Marketing revenues	413	486	1,657	1,788
Other revenues	40	183	261	500
Total revenues and other	194,672	142,947	441,276	306,211
Expenses and other:				
Lease operating expenses	50,957	51,649	156,765	137,468
Electricity generation expenses	3,781	6,130	14,705	13,855
Transportation expenses	2,067	2,318	5,935	7,640
Marketing expenses	398	437	1,670	1,424
General and administrative expenses	16,434	13,429	46,932	37,896
Depreciation, depletion, and amortization	27,664	21,729	75,904	62,017
Taxes, other than income taxes	9,249	8,317	28,683	25,288
Losses (gains) on natural gas derivatives	3,008	(1,879)	10,342	(1,879)
Other operating (income) expenses	(550)	400	3,814	522
Total expenses and other	113,008	102,530	344,750	284,231
Other income (expenses):				
Interest expense	(8,597)	(9,877)	(26,362)	(26,828)
Other, net	(77)	347	79	135
Total other income (expenses)	(8,674)	(9,530)	(26,283)	(26,693)
Reorganization items, net	(170)	13,781	(426)	23,192
Income before income taxes	72,820	44,668	69,817	18,479
Income tax expense	20,171	7,683	19,294	3,145
Net income	52,649	36,985	50,523	15,334
Series A preferred stock dividends	—	(86,642)	—	(97,942)
Net income (loss) attributable to common stockholders	$ 52,649	$ (49,657)	$ 50,523	$ (82,608)
Net income (loss) per share attributable to common stockholders:				
Basic	$ 0.65	$ (0.70)	$ 0.62	$ (1.70)
Diluted	$ 0.65	$ (0.70)	$ 0.62	$ (1.70)

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, 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 (loss)	—	—	—	—	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 income (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.

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BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Nine-Month Period Ended September 30, 2019					
	Series A Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
	(in thousands)					
December 31, 2018	$ —	$ 82	$ 914,540	$ (24,218)	$ 116,042	$ 1,006,446
Shares withheld for payment of taxes on equity awards and other	—	—	(270)	—	—	(270)
Stock based compensation	—	—	1,498	—	—	1,498
Purchases of treasury stock	—	—	—	(24,375)	—	(24,375)
Purchase of rights to common stock(1)	—	—	(20,265)	20,265	—	—
Common stock issued to settle unsecured claims	—	3	(3)	—	—	—
Dividends declared on common stock, $0.12/share	—	—	—	—	(10,072)	(10,072)
Net income (loss)	—	—	—	—	(34,098)	(34,098)
March 31, 2019	—	85	895,500	(28,328)	71,872	939,129
Shares withheld for payment of taxes on equity awards and other	—	—	(675)	—	—	(675)
Stock based compensation	—	—	2,497	—	—	2,497
Purchases of treasury stock	—	—	—	(10,897)	—	(10,897)
Dividends declared on common stock, $0.12/share	—	—	—	—	(9,710)	(9,710)
Net income (loss)	—	—	—	—	31,972	31,972
June 30, 2019	—	85	897,322	(39,225)	94,134	952,316
Shares withheld for payment of taxes on equity awards and other	—	—	(294)	—	—	(294)
Stock based compensation	—	—	2,393	—	—	2,393
Dividends declared on common stock, $0.12/share	—	—	—	—	(9,720)	(9,720)
Net income (loss)	—	—	—	—	52,649	52,649
September 30, 2019	$ —	$ 85	$ 899,421	$ (39,225)	$ 137,063	$ 997,344

(1) In 2018, we entered into several settlement agreements with general unsecured creditors from our bankruptcy process. We paid approximately $20 million to purchase their claims to our common stock. These claims were settled in February 2019 with no shares issued.

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

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

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in thousands)	
Cash flows from operating activities:		
Net income	$ 50,523	$ 15,334
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	75,904	62,017
Amortization of debt issuance costs	3,786	4,042
Stock-based compensation expense	6,277	3,502
Deferred income taxes	19,294	3,146
Increase (decrease) in allowance for doubtful accounts	427	(20)
Other operating expenses	4,744	522
Reorganization expenses, net (non-cash)	—	(24,199)
Derivative activities:		
Total losses	2,796	129,902
Cash settlements on derivatives	26,731	(47,161)
Cash payments on early-terminated derivatives	—	(126,949)
Changes in assets and liabilities:		
Increase in accounts receivable	(6,690)	(11,546)
Increase in other assets	(10,547)	(774)
(Decrease) increase in accounts payable and accrued expenses	(12,344)	5,574
Decrease in other liabilities	(5,108)	(6,056)
Net cash provided by operating activities	155,793	7,334
Cash flows from investing activities:		
Capital expenditures:		
Development of oil and natural gas properties	(153,420)	(74,447)
Purchases of other property and equipment	(12,394)	(11,305)
Acquisition of properties	(2,819)	—
Proceeds from sale of property and equipment and other	969	3,377
Net cash used in investing activities	(167,664)	(82,375)
Cash flows from financing activities:		
Borrowings under RBL credit facility	252,182	197,210
Repayments on RBL credit facility	(242,182)	(576,210)
Dividends paid on common stock	(29,431)	—
Purchase of treasury stock	(36,139)	(20,265)
Shares withheld for payment of taxes on equity awards and other	(1,239)	(422)
Issuance of 2026 Senior Unsecured Notes	—	400,000
Debt issuance costs	—	(9,173)
IPO proceeds net of issuance costs	—	134,362
Repurchase of common stock	—	(23,712)
Payment to preferred stockholders in conversion	—	(60,273)
Dividends paid on Series A Preferred Stock	—	(11,301)
Net cash (used in) provided by financing activities	(56,809)	30,216
Net decrease in cash, cash equivalents and restricted cash	(68,680)	(44,825)
Cash, cash equivalents and restricted cash:		
Beginning	68,680	68,738
Ending	$ —	$ 23,913

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 is the sole member of Berry Petroleum Company, LLC ("Berry LLC").

As the context may require, the “Company”, “we”, “our” or similar words refer to (i) Berry Corp. and Berry LLC, its consolidated subsidiary, as a whole or (ii) either Berry Corp. or Berry LLC.

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 (the “U.S.”), in California (in the San Joaquin and Ventura basins), Utah (in the Uinta basin), and Colorado (in the Piceance basin).

Principles of Consolidation and Reporting

The condensed consolidated financial statements were prepared in conformity with U.S. generally accepted accounting principles ("GAAP"), which requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. In management’s opinion, the accompanying financial statements contain all normal, recurring adjustments that are necessary to fairly present our interim unaudited condensed consolidated financial statements as of September 30, 2019. We eliminated all significant intercompany transactions and balances 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.

We prepared this report pursuant to the rules and regulations of the U.S. Security and Exchange Commission ("SEC") applicable to interim financial information, which permit the omission of certain disclosures to the extent they have not changed materially since the latest annual financial statements. We believe our disclosures are adequate to make the disclosed information not misleading. The results reported in these unaudited condensed consolidated financial statements may not accurately forecast results for future periods. This Form 10-Q should be read in conjunction with the consolidated financial statements and the notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2018.

Recently Adopted Accounting Standards

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 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. As such, we adopted these rules in the first quarter of 2019 and applied the modified retrospective approach, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. We have performed an analysis of existing contracts and determined adoption did not have a material impact on our condensed consolidated financial statements. In addition, we have evaluated the changes to relevant business practices, accounting policies and control activities and we did not experience a material change in our revenue accounting as a result of the adoption of these rules. Refer to Note 8 for additional disclosure information.

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 are currently identifying our lease population in accordance with the new lease standard. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and we do not expect a material impact on our consolidated results of operations.

Note 2 - Debt

The following table summarizes our outstanding debt:

	September 30, 2019	December 31, 2018	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility[(1)]	$ 10,000	$ —	variable rates 3.8% (2019) and 4.5% (2018), respectively	June 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves and lien on other assets
2026 Senior Unsecured Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	410,000	400,000			
Less: Debt Issuance Costs	(7,710)	(8,214)			
Long-Term Debt, net	$ 402,290	$ 391,786			

(1) As of September 30, 2019 our RBL Facility had $10 million outstanding at a LIBOR rate of 3.8%.

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At September 30, 2019 and December 31, 2018, debt issuance costs for the RBL Facility (as defined below) reported in "other noncurrent assets" on the balance sheet were approximately $12 million and $16 million net of amortization, respectively. The amortization of debt issuance costs is presented in interest expense on the condensed consolidated statements of operations. At September 30, 2019 and December 31, 2018, debt issuance costs, net of amortization, for the 2026 Senior Unsecured Notes were both approximately $8 million.

For the three months ended September 30, 2019 and September 30, 2018, the amortization expense for the RBL Facility and 2026 Senior Unsecured Notes were both approximately $1 million. For the nine months ended September 30, 2019 and September 30, 2018, these amounts were both approximately $4 million.

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 $385 million and $368 million at September 30, 2019 and December 31, 2018, respectively.

The RBL Facility

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 April 2019, we completed a borrowing base redetermination under our RBL Facility that resulted in our borrowing base being set at $750 million and we reaffirmed our elected commitment amount at $400 million. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

We were in compliance with all financial covenants as of September 30, 2019.

As of September 30, 2019, we had approximately $381 million of available borrowing capacity under the RBL Facility.

As of September 30, 2019 and December 31, 2018, we had letters of credit outstanding of approximately $9 million and $7 million, respectively, under our RBL facility. These letters of credit were issued to support ordinary course of business marketing, insurance, regulatory and other matters. As of October 31, 2019 we had letters of credit outstanding of approximately $7 million, under our RBL facility.

Corporate Organization

Berry Corp., as Berry LLC's parent company, has no independent assets or operations. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. Berry Corp. and Berry LLC currently do not have any other subsidiaries. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than under the RBL Facility. The RBL Facility permits Berry LLC to make distributions to Berry Corp. provided certain conditions are met. The conditions are currently met with significant margin. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

Note 3 - Derivatives

We utilize derivatives, such as swaps, puts, and calls to hedge a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices. We target covering our operating expenses and a majority of our fixed charges, including maintenance capital expenditures, interest and dividends, with the oil hedges for a period of up to two years out. We have hedged a portion of our exposure to differentials between ICE Brent oil ("Brent") and NYMEX West Texas Intermediate oil ("WTI"). Additionally, we target fixing the price for a large portion of our natural gas purchases used in our steam operations for up to two years. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations, which we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

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

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 purchased oil puts, we receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For some of our purchased puts we paid a premium at the time the positions were created and for others, the premium payment is deferred until the time of settlement. We have mitigated the exposure to a substantial portion of the deferred premium payments by entering into offsetting put positions. We paid approximately $1 million and $21 million of the net deferred premiums during the three and nine months ended September 30, 2019, which included premiums we received during these periods. As of September 30, 2019 we have offsetting put positions with an outstanding net deferred premium of approximately $1 million, which is reflected in the mark-to-market valuation and will be payable through the first quarter of 2020.

For our sold oil calls, we would make settlement payments for prices above the indicated weighted-average price per barrel of Brent.

For fixed-price gas purchase 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.

We use oil swaps and puts to protect against decreases in the oil price and natural gas swaps to protect against increases in natural gas prices. We do not enter into derivative contracts for speculative trading purposes and have not accounted for our derivatives as cash-flow or fair-value hedges. 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 condensed consolidated statements of operations and (gains) losses on natural gas hedges are presented in the expenses and other section of the condensed consolidated statements of operations.

BERRY PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

As of September 30, 2019, we had the following crude oil production and gas purchases hedges.

	Q4 2019	FY 2020	FY 2021
Fixed Price Oil Swaps (Brent):			—
Hedged volume (MBbls)	1,656	5,856	730
Weighted-average price ($/Bbl)	$ 70.20	$ 64.25	$ 58.50
Fixed Price Oil Swaps (WTI):			
Hedged volume (MBbls)	92	121	—
Weighted-average price ($/Bbl)	$ 61.75	$ 61.75	$ —
Oil basis differential swaps (Brent-WTI basis swaps):			
Hedged volume (MBbls)	46	—	—
Weighted-average price ($/Bbl)	$ (1.29)	$ —	$ —
Sold Oil Calls Options (Brent):			
Hedged volume (MBbls)	92	—	—
Weighted-average price ($/Bbl)	$ 81.00	$ —	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	4,905,000	17,385,000	900,000
Weighted-average price ($/MMBtu)	$ 2.90	$ 2.88	$ 2.50
Fixed Price Gas Purchase Swaps (SoCal Citygate):			
Hedged volume (MMBtu)	460,000	1,525,000	—
Weighted-average price ($/MMBtu)	$ 3.80	$ 3.80	$ —

Our commodity derivatives are measured at fair value using industry-standard models with various inputs including publicly available underlying commodity prices and forward curves, and all are classified as Level 2 in the required fair value hierarchy for the periods presented. These commodity derivatives are subject to counterparty netting. The following tables present the fair values (gross and net) of our outstanding derivatives as of September 30, 2019 and December 31, 2018:

	September 30, 2019			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented on the Balance Sheet
		(in thousands)		
Assets:				
Commodity Contracts	Current assets	$ 59,600	$ (9,571)	$ 50,029
Commodity Contracts	Non-current assets	14,982	(1,319)	13,663
Liabilities:				
Commodity Contracts	Current liabilities	(13,105)	9,571	(3,534)
Commodity Contracts	Non-current liabilities	(1,319)	1,319	—
Total derivatives		$ 60,158	$ —	$ 60,158

	December 31, 2018			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented on the Balance Sheet
		(in thousands)		
Assets:				
Commodity Contracts	Current assets	$ 89,981	$ (1,385)	$ 88,596
Commodity Contracts	Non-current assets	3,289	—	3,289
Liabilities:				
Commodity Contracts	Current liabilities	(1,385)	1,385	—
Total derivatives		$ 91,885	$ —	$ 91,885

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. We do not receive collateral from our counterparties.

We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, our RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from Standards & Poor's or Moody's, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which partially mitigates the counterparty nonperformance risk.

Note 4 - 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.

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, 2019 and December 31, 2018. 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, 2019, we are not aware of material indemnity claims pending or threatened against us.

As of September 30, 2019, we had entered into agreements to replace our Bakersfield, California office lease for approximately $11 million in aggregate over 8 years beginning August 2019. The annual costs under our former office lease, which ended in October 2019, were similar to the costs under the new leases.

Note 5 - Equity

Cash Dividends

Our board of directors approved a $0.12 per share quarterly cash dividend on our common stock each quarter in 2019. We paid the third quarter dividend in October 2019 and declared the fourth quarter dividend in November 2019, which is payable in January 2020.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock they authorized initial repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Petroleum to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. For the three months ended September 30, 2019, we did not repurchase shares under the stock repurchase program. For the nine months ended September 30, 2019, we repurchased 3,200,162 shares at an average price of $11.02 per share for $35 million, which is reflected as treasury stock. The Company has repurchased a total of 3,648,823 shares under the stock repurchase program for $39 million as of September 30, 2019.

Stock-Based Compensation

In March 2019, the Company granted awards of 706,314 shares of restricted stock units ("RSUs"), which will vest annually in equal amounts over three years and 553,902 performance-based restricted stock units ("PSUs"), which will cliff vest at two or three years. The fair value of these awards was approximately $16 million.

The RSUs awarded are service-based awards. The PSUs awarded include a market objective measured against both absolute total stockholder return ("Absolute TSR") and total stockholder return relative ("Relative TSR"), to the Vanguard World Fund - Vanguard Energy ETF index (the "Index") over the performance period, assuming the reinvestment of dividends. Depending on the results achieved during the two or three year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 200% of the Target Shares granted.

The fair value of the PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the Index over the performance periods. The expected volatility of the Company's common stock at the date of grant was estimated based on blended historical average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the current annualized declared dividend. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate two and three year performance measurement period.

Note 6 - Supplemental Disclosures to the Financial Statements

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

	September 30, 2019	December 31, 2018
	(in thousands)	
Prepaid expenses	$ 4,533	$ 4,656
Materials and supplies	8,143	5,461
Oil inventories	3,193	3,786
Other	466	464
Total	$ 16,335	$ 14,367

Other non-current assets at September 30, 2019 and December 31, 2018, included approximately $12 million and $16 million of deferred financing costs, net of amortization, respectively.

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

	September 30, 2019	December 31, 2018
	(in thousands)	
Accounts payable-trade	$ 14,118	$ 13,564
Accrued expenses	59,579	66,417
Royalties payable	20,148	26,189
Taxes other than income tax liability	10,919	10,766
Accrued interest	3,516	10,500
Dividends payable	10,063	9,992
Asset retirement obligation - current portion	26,659	6,372
Other	358	318
Total	$ 145,360	$ 144,118

The increase in the long-term portion of the asset retirement obligation largely reflected revisions to timing and cost estimates of $57 million, $6 million for new wells, and accretion expense of $5 million. A significant portion of the change in estimate was a result of California's new idle well regulations which became effective in the second quarter and accelerated the timing of abandonment of certain long existing idle wells. These increases were partially offset by liabilities settled during the period of $15 million and an increase to the current portion of the asset retirement obligation of $20 million due to the change in timing and estimated costs.

Other non-current liabilities at September 30, 2019 and December 31, 2018 included approximately $29 million and $15 million of greenhouse gas liability, respectively.

Supplemental Information on the Statement of Operations

Other operating (income) expenses mainly consist of excess abandonment costs, as well as gain (loss) on sale of assets.

Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
	2019	2018
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 8,474	$ 1,115
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 30,136	$ 19,199
Income taxes	$ —	$ —
Reorganization items, net	$ —	$ 1,007
Supplemental Disclosures of Investing Activities:		
Decrease in accrued liabilities related to purchases of property and equipment	$ 4,613	$ 8,832

The following table provides a reconciliation of cash, cash equivalents and restricted cash as reported in the condensed consolidated statements of cash flows to the line items within the condensed consolidated balance sheets:

	Nine Months Ended September 30,	
	2019	2018
	(in thousands)	
Beginning of Period		
Cash and cash equivalents	$ 68,680	$ 33,905
Restricted cash	—	34,833
Cash, cash equivalents and restricted cash	$ 68,680	$ 68,738
Ending of Period		
Cash and cash equivalents	$ —	$ 23,856
Restricted cash	—	57
Cash, cash equivalents and restricted cash	$ —	$ 23,913

Restricted cash was associated with cash reserved to settle claims with general unsecured creditors. Cash and cash equivalents consist primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value. As part of our cash management system, we use a controlled disbursement account to fund cash distribution checks presented for payment by the holder. Checks issued but not yet presented to banks may result in overdraft balances for accounting purposes in the accounts payable and accrued expenses account.

Note 7 - Earnings Per Share

We calculate basic earnings (loss) per share by dividing net income (loss) attributable to common stockholders by the weighted-average number of common shares outstanding during the three and nine months ended September 30, 2019 which is approximately 81 million and 82 million shares, respectively. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, are considered common shares outstanding and are included in the computation of net income (loss) per share. Our initial capitalization included the issuance of 32,920,000 shares of common stock and another 7,080,000 shares reserved to settle claims of unsecured creditors, all of which were included in our computation of net income (loss) per share until the claims were settled and the shares issued. At the end of February 2019, we finalized settlement of these claims and issued approximately 2,770,000 shares. In all prior periods presented we retrospectively adjusted the weighted average shares in our earnings per share calculations for the ultimate shares issued.

BERRY PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

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 were included in the diluted EPS calculation for the three and nine months ended September 30, 2019, as all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO of our common stock in July 2018. No Series A Preferred Stock were included in the diluted EPS calculation for the three and nine months ended September 30, 2018 as their effect was anti-dilutive under the "if converted" method. The RSUs are not a participating security as the dividends are forfeitable. We included 69,000 and 145,000 incremental RSU shares in the diluted EPS calculation for the three and nine months ended September 30, 2019. No incremental RSU shares were included in the diluted EPS calculation for the three and nine months ended September 30, 2018, as their effect was anti-dilutive under the "if-converted" method. No PSU's were included in the EPS calculations for any of the periods presented due to their contingent nature.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands except per share amounts)			
Basic EPS calculation				
Net income	$ 52,649	$ 36,985	$ 50,523	15,334
less: Series A Preferred Stock dividends and conversion to common stock	—	(86,642)	—	(97,942)
Net income (loss) attributable to common stockholders	$ 52,649	$ (49,657)	$ 50,523	$ (82,608)
Weighted-average shares of common stock outstanding	80,982	70,940	81,703	48,587
Basic earnings (loss) per share[(2)]	$ 0.65	$ (0.70)	$ 0.62	$ (1.70)
Diluted EPS calculation				
Net income	$ 52,649	$ 36,985	$ 50,523	$ 15,334
less: Series A Preferred Stock dividends and conversion to common stock	—	(86,642)	—	(97,942)
Net income (loss) attributable to common stockholders	$ 52,649	$ (49,657)	$ 50,523	$ (82,608)
Weighted-average shares of common stock outstanding	80,982	70,940	81,703	48,587
Dilutive effect of potentially dilutive securities[(1)]	69	—	145	—
Weighted-average common shares outstanding - diluted	81,051	70,940	81,848	48,587
Diluted earnings (loss) per share[(2)]	$ 0.65	$ (0.70)	$ 0.62	$ (1.70)

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

Note 8 - Revenue Recognition

We account for revenue in accordance with the Accounting Standards Codification 606, Revenue from Contracts with Customers, which we adopted on January 1, 2019, using the modified retrospective method, which was applied to all contracts that were not completed as of that date. Prior period results were not adjusted and continue to be reported under the accounting standards in effect for the prior period. The new standard did not affect the timing of our revenue recognition and did not impact net income; accordingly, we did not record an adjustment to the opening balance of retained earnings.

We adopted the practical expedient related to disclosing the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied at the end of the reporting period. The performance obligations that are unsatisfied at the end of a reporting period relate solely to future volumes that we have yet to sell. As such, these are wholly unsatisfied performance obligations as each unit of product represents a separate performance obligation as well as a wholly unsatisfied promise to transfer a distinct good that forms part of a single performance obligation.

We derive substantially all of our revenue from sales of oil, natural gas and natural gas liquids ("NGL"), with the remaining revenue generated from sales of electricity and marketing activities.

The following is a description of our principal activities from which we generate revenue. Revenues are recognized when a customer obtains control of promised goods or services, in an amount that reflects the consideration we expect to receive in exchange for those goods or services.

Oil, Natural Gas and NGLs

We recognize revenue from the sale of our oil, natural gas and NGLs production when delivery has occurred and control passes to the customer. Our oil and natural gas contracts are short term, typically less than a year and our NGL contracts are both short and long term. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Our commodity sales contracts are indexed to a market price or an average index price. We recognize revenue in the amount that we have a right to invoice once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following invoicing.

Electricity Sales

The electrical output of our cogeneration facilities that is not used in our operations is sold to the California market based on market pricing, which includes capacity payments. The majority of the portion sold from three of our cogeneration facilities is sold under long-term contracts to two California utility companies, based on the market pricing. Revenue is recognized over time when obligations under the terms of a contract with our customer are satisfied; generally, this occurs upon delivery of the electricity. Revenue is measured as the amount of consideration we expect to receive based on average index pricing with payment due the month following delivery. Capacity payments are based on a fixed annual amount per kilowatt hour and monthly rates vary based on seasonality, which is consistent with how we earn the capacity payment. Capacity payments are settled monthly. We consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments. We report electricity revenue as electricity sales on our consolidated statements of operations.

Marketing Revenue

Marketing revenue primarily includes our activities associated with transporting and marketing third-party volumes. These sales are made under the same agreements with the same purchaser as our natural gas sales discussed above. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Revenues are presented excluding costs incurred prior to transferring control of these volumes to the customer, or the costs to purchase these volumes when we are acting as the principal. The revenues and expenses related to the sale and purchase of third-party volumes are presented separately as marketing revenue and marketing expenses on the condensed consolidated statements of operations.

Disaggregated Revenue

As a result of adoption of this standard, we are now required to disclose the following information regarding revenue from contracts with customers on a disaggregated basis.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Oil sales	$ 136,710	$ 138,699	$ 392,325	$ 387,065
Natural gas sales	4,067	6,437	14,867	18,400
Natural gas liquids sales	473	1,868	2,067	4,548
Electricity sales	7,460	14,268	22,553	25,691
Marketing revenues	413	486	1,657	1,788
Revenues from contracts with customers	149,123	161,758	433,469	437,492
Gains (losses) on oil derivatives	45,509	(18,994)	7,546	(131,781)
Other revenues	40	183	261	500
Total revenues and other	$ 194,672	$ 142,947	$ 441,276	$ 306,211

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 our interim unaudited consolidated financial statements and related notes presented in this Quarterly Report on Form 10-Q, as well as our audited consolidated financial statements and related notes thereto contained in our Annual Report on Form 10-K for the year ended December 31, 2018 (the "Annual Report") filed with the Securities and Exchange Commission ("SEC"). When we use the terms "we," "us," "our," the "Company" or similar words in this report, we are referring to Berry Corp. and its subsidiary, Berry LLC.

Our Company

We are a western United States independent upstream energy company with a focus on low risk, long-lived, oil reserves in conventional reservoirs. Most of our assets are in the San Joaquin basin of California. Our long-lived, high-margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive levered free cash flow through commodity price cycles. We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and, to a lesser extent, our Rockies assets including low-cost, oil-rich reservoirs in the Uinta basin of Utah and low geologic risk natural gas resource plays in the Piceance basin in Colorado. Successful execution of our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient, consistent and predictable production growth, as well as the ability to continue returning capital to our stockholders.

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) cash general and administrative expenses; and (e) 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, and amortization; 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 generation 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 derivative settlements (received or paid) for gas purchases. Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. 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. Additionally, we strive to minimize the variability of our fuel gas costs for our steam operations with gas hedges. 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.

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.

Capital Expenditures

For the three and nine months ended September 30, 2019, our capital expenditures were approximately $63 million and $169 million, respectively, on an accrual basis excluding acquisitions. For the three and nine months ended September 30, 2019, approximately 93% and 91%, respectively, of this total was directed to California oil operations.

Our 2019 anticipated capital expenditure budget is approximately $195 to $225 million. Using the mid-point of this range, this represents an increase of approximately 42% over 2018 capital expenditures. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2019 capital development programs while producing positive Levered Free Cash Flow. Our 2019 capital program is focused on growing our oil production in California. We anticipate oil production will be 86% to 88% of total production in 2019, compared to 82% in 2018. We structured our 2019 capital program to result in more drilling in the first half of the year than we expect in the second half. Consistent with our plan, we drilled 292 wells during the nine months ended September 30, 2019, including 82 wells in the third quarter of 2019. For 2019, we expect to drill approximately 360 to 380 gross development wells, almost all of which will be in California for oil production. During the remainder of 2019, we plan to employ up to three drilling rigs in California. We also expect to continue generating growth in the fourth quarter as wells continue to come online and we realize the full effects of steam injection.

The table below sets forth the expected allocation of our 2019 capital expenditure budget by area as compared to the allocation of our 2018 capital expenditures.

	Capital Expenditure by Area	
	2019 Budget	**2018 Actual**
	(in millions)	
California	$ 185-209	$ 126
Rockies	4-9	17
Corporate	6-7	5
Total	$ 195-225	$ 148

The amount and timing of these capital expenditures is within our control and subject to our 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.

2019 Guidance

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

	2019 Guidance	
	Low	High
Average daily production (MBoe/d)	28	31
% Oil	~86%	
Operating expenses ($/Boe)	$18.00	$19.50
Taxes, other than income taxes ($/Boe)	$4.25	$4.75
Adjusted General & Administrative Expenses ($/Boe)	$4.25	$4.75
Capital Expenditures (millions)	$195	$225

Business Environment, Market Conditions and Seasonality

The oil and gas industry is heavily influenced by commodity prices. Average oil prices were lower for the three months ended September 30, 2019 compared to the three months ended June 30, 2019 and the three months ended September 30, 2018. Brent crude oil contract prices ranged from $56.23 per Bbl to $69.02 per Bbl during the third quarter of 2019. In California, the price we pay for fuel gas purchases is generally based on the Kern, Delivered Index which was as low as $1.74 per MMBtu and as high as $4.09 per MMBtu during the third quarter of 2019, while we paid an average of $2.67 in this period. Our revenue, costs, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production and the prices we pay for our natural gas purchases which will continue to be affected by a variety of factors, as discussed in Risk Factors in our Annual Report.

The following table presents the average Brent, WTI, and Kern, Delivered prices for the three months ended September 30, 2019, June 30, 2019 and September 30, 2018 and for the nine months ended September 30, 2019 and September 30, 2018:

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
Brent oil ($/Bbl)	$ 62.03	$ 68.47	$ 75.84	$ 64.75	$ 72.74
WTI oil ($/Bbl)	$ 56.33	$ 59.86	$ 69.60	$ 57.03	$ 66.83
Kern, Delivered natural gas ($/MMBtu)	$ 2.50	$ 2.07	$ 4.12	$ 3.19	$ 3.01

California oil prices are Brent-influenced as California refiners import approximately 70% of the state’s demand by waterborne supply, primarily from the Middle East and South America. There is a closer correlation of prices in California to Brent pricing than to WTI. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, will allow us to continue to realize strong cash margins in California.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for Utah 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, availability of transportation capacity from producing areas and seasonal impacts. We purchase substantially more natural gas for our steamfloods and cogeneration facilities, than we produce and sell. Consequently, higher gas prices have a negative impact on our operating costs. However, we mitigate a portion of this exposure by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. Additionally, we strive to minimize the variability of our fuel gas costs for our steam operations by hedging a portion of such gas purchases and have recently increased the amount of gas purchases we hedge. Also, the negative impact of higher gas prices is partially offset by higher gas sales for the gas we produce. We have negotiated terms of a new power purchase agreement for our 18 MW cogeneration facility which begins in December 2019 for a period of seven years.

Our earnings are also affected by the performance of our natural gas powered 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. We generally receive significantly more revenue from these cogeneration facilities in the summer months, June through September, due to negotiated capacity payments we receive.

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 and rain.

Summary By Area

The following table shows a summary by area of our selected historical financial information and operating data for the periods indicated.

	California (San Joaquin and Ventura basins) Three Months Ended			Rockies (Uinta and Piceance basins) Three Months Ended		
($ in thousands, except prices)	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	June 30, 2019	September 30, 2018
Oil, natural gas and natural gas liquids sales	$ 124,540	$ 120,917	$ 124,007	$ 16,711	$ 15,991	$ 22,998
Operating income[(a)]	$ 49,185	$ 47,809	$ 62,791	$ 1,241	$ 954	$ 7,176
Depreciation, depletion, and amortization (DD&A)	$ 24,360	$ 20,460	$ 17,908	$ 3,303	$ 3,194	$ 3,268
Average daily production (MBoe/d)	23.0	20.8	19.5	6.6	6.6	7.9
Production (oil % of total)	100%	100%	100%	41%	41%	35%
Realized sales prices:						
Oil (per Bbl)	$ 59.00	$ 63.91	$ 69.13	$ 48.82	$ 44.92	$ 57.45
NGLs (per Bbl)	$ —	$ —	$ —	$ 12.10	$ 16.86	$ 37.75
Gas (per Mcf)	$ —	$ —	$ —	$ 2.12	$ 2.16	$ 2.55
Capital expenditures[(b)]	$ 59,076	$ 52,374	$ 35,124	$ 2,064	$ 1,443	$ 2,624

(a) Operating income comprises oil, natural gas and NGL sales, offset by operating expenses, general and administrative expenses, DD&A, and taxes, other than income taxes.

(b) Excludes corporate capital expenditures.

Production and Prices

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

	Three Months Ended		
	September 30, 2019	June 30, 2019	September 30, 2018
Average daily production:(1)(3)			
Oil (MBbl/d)	25.7	23.5	22.3
Natural Gas (MMcf/d)	20.9	20.8	27.4
NGL (MBbl/d)	0.4	0.4	0.5
Total (MBoe/d)(2)	29.6	27.4	27.4
Total Production:(3)			
Oil (MBbl)	2,360	2,142	2,049
Natural gas (MMcf)	1,920	1,894	2,523
NGLs (MBbl)	39	39	49
Total (MBoe)(2)	2,719	2,497	2,520
Weighted-average realized sales prices:			
Oil without hedges ($/Bbl)	$ 57.92	$ 61.69	$ 67.67
Oil with hedges ($/Bbl)	$ 65.23	$ 61.82	$ 67.23
Natural gas ($/Mcf)	$ 2.12	$ 2.16	$ 2.55
NGL ($/Bbl)	$ 12.10	$ 16.86	$ 37.75
Average Benchmark prices:			
Oil (Bbl) – Brent	$ 62.03	$ 68.47	$ 75.84
Oil (Bbl) – WTI	$ 56.33	$ 59.86	$ 69.60
Gas (MMBtu) – Kern, Delivered(4)	$ 2.50	$ 2.07	$ 4.12

(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(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 three months ended September 30, 2019, the average prices of Brent oil and Henry Hub natural gas were $62.03 per Bbl and $2.38 per MMBtu respectively, resulting in an oil-to-gas ratio of approximately 4 to 1 on an energy equivalent basis.

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

(4) Kern, Delivered Index is the relevant index used for gas purchases in California.

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

	Three Months Ended		
	September 30, 2019	June 30, 2019	September 30, 2018
Average daily production (MBoe/d):(1)			
California	23.0	20.8	19.5
Rockies	6.6	6.6	7.1
East Texas(2)	—	—	0.7
Total average daily production	29.6	27.4	27.4

(1) Production represents volumes sold during the period.

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

Average daily production, including sales of inventory, increased 8% for the three months ended September 30, 2019 compared to the three months ended June 30, 2019, due to production response from our development capital focused on California oil. Our California production of 23.0 MBoe/d for the third quarter of 2019 increased 10% from the second quarter of 2019.

Average daily production volumes increased 8% for the three months ended September 30, 2019 as compared to the three months ended September 30, 2018 due to production response from development capital spending throughout 2018 and 2019, which offset the natural decline of our properties as well as the sale of our East Texas properties in November 2018. Production increased 18% in California, where the substantial majority of our development capital was deployed, for the three months ended September 30, 2019 compared to the same period in 2018. This increase strongly demonstrated the ability of our California properties to respond to capital and perform as expected.

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

	Nine Months Ended	
	September 30, 2019	September 30, 2018
Average daily production:(1)(3)		
Oil (MBbl/d)	24.5	21.5
Natural Gas (MMcf/d)	20.4	27.7
NGL (MBbl/d)	0.4	0.6
Total (MBoe/d)(2)	28.3	26.7
Total Production:(3)		
Oil (MBbl)	6,673	5,867
Natural gas (MMcf)	5,565	7,555
NGLs (MBbl)	116	157
Total (MBoe)(2)	7,717	7,284
Weighted-average realized sales prices:		
Oil without hedges ($/Bbl)	$ 58.79	$ 65.97
Oil with hedges ($/Bbl)	$ 63.09	$ 57.96
Natural gas ($/Mcf)	$ 2.67	$ 2.44
NGL ($/Bbl)	$ 17.74	$ 28.93
Average Benchmark prices:		
Oil (Bbl) – Brent	$ 64.75	$ 72.74
Oil (Bbl) – WTI	$ 57.03	$ 66.83
Gas (MMBtu) – Kern, Delivered(4)	$ 3.19	$ 3.01

(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(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 nine months ended September 30, 2019, the average prices of Brent oil and Henry Hub natural gas were $64.75 per Bbl and $2.62 per MMBtu, respectively, resulting in an oil-to-gas ratio of approximately 4 to 1 on an energy equivalent basis.

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

(4) Kern, Delivered Index is the relevant index used for gas purchases in California.

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

	Nine Months Ended	
	September 30, 2019	September 30, 2018
Average daily production (MBoe/d):(1)		
California	21.6	19.0
Rockies	6.7	6.9
East Texas(2)	—	0.8
Total average daily production	28.3	26.7

(1) Production represents volumes sold during the period.

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

Average daily production volumes increased 6% for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018 due to production response from development capital spending throughout 2018 and 2019, which offset the natural decline of our properties as well as the sale of our East Texas properties in November 2018. For the nine months ended September 30, 2019 California production increased 14% compared to the nine months ended September 30, 2018 as the substantial majority of our development capital was deployed throughout our California operations showing the strong ability of our California properties to respond to capital and perform as expected.

Results of Operations

Three Months Ended September 30, 2019 compared to Three Months Ended June 30, 2019.

	Three Months Ended			
	September 30, 2019	June 30, 2019	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 141,250	$ 136,908	$ 4,342	3 %
Electricity sales	7,460	5,364	2,096	39 %
Gain (losses) on oil derivatives	45,509	27,276	18,233	67 %
Marketing and other revenues	453	518	(65)	(13)%
Total revenues and other	$ 194,672	$ 170,066	$ 24,606	14 %

Revenues and Other

Oil, natural gas and NGL sales increased $4 million, or 3%, to approximately $141 million for the three months ended September 30, 2019 compared to the three months ended June 30, 2019. This increase reflected higher oil volumes that were partially offset by lower oil prices.

Electricity sales represent sales to utilities, and increased $2 million, or 39%, to approximately $7 million for the three months ended September 30, 2019 compared to the three months ended June 30, 2019. The increase primarily reflected higher unit sales prices including seasonal capacity payments during the third quarter of 2019 compared to the second quarter.

Gains on oil derivatives were approximately $46 million, including settled gains of $17 million, for the three months ended September 30, 2019 compared to gains of approximately $27 million, primarily consisting of mark-to-market gains, for the three months ended June 30, 2019. Gains for the third quarter of 2019 were the result of lower oil prices relative to the fixed prices of our derivative contracts.

Marketing and other revenues were comparable for the three months ended September 30, 2019 and the three months ended June 30, 2019. Marketing revenues in these periods represented sales of natural gas purchased from third-parties.

	Three Months Ended			
	September 30, 2019	June 30, 2019	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 50,957	$ 47,879	$ 3,078	6 %
Electricity generation expenses	3,781	3,164	617	20 %
Transportation expenses	2,067	1,694	373	22 %
Marketing expenses	398	421	(23)	(5)%
General and administrative expenses	16,434	16,158	276	2 %
Depreciation, depletion and amortization	27,664	23,654	4,010	17 %
Taxes, other than income taxes	9,249	11,348	(2,099)	(18)%
Losses (gains) on natural gas derivatives	3,008	9,449	(6,441)	(68)%
Other operating (income) expenses	(550)	3,119	(3,669)	(118)%
Total expenses and other	113,008	116,886	(3,878)	(3)%
Other income (expenses):				
Interest expense	(8,597)	(8,961)	364	(4)%
Other, net	(77)	—	(77)	(100)%
Reorganization items, net	(170)	(26)	(144)	554 %
Income before income taxes	72,820	44,193	28,627	65 %
Income tax expense	20,171	12,221	7,950	65 %
Net income	$ 52,649	$ 31,972	$ 20,677	65 %
Expenses per Boe:(1)				
Lease operating expenses	$ 18.74	$ 19.18	$ (0.44)	(2)%
Electricity generation expenses	1.39	1.27	0.12	9 %
Electricity sales(1)	(2.74)	(2.15)	(0.59)	27 %
Transportation expenses	0.76	0.68	0.08	12 %
Transportation sales(1)	(0.01)	(0.04)	0.03	(75)%
Marketing expenses	0.15	0.17	(0.02)	(12)%
Marketing revenues(1)	(0.15)	(0.17)	0.02	(12)%
Derivatives settlements paid for gas purchases(1)	0.77	1.44	(0.67)	(47)%
Total operating expenses	$ 18.90	$ 20.38	$ (1.48)	(7)%
Total unhedged operating expenses(2)	$ 18.13	$ 18.94	$ (0.81)	(4)%
General and administrative expenses(3)	$ 6.04	$ 6.47	$ (0.43)	(7)%
Depreciation, depletion and amortization	$ 10.17	$ 9.47	$ 0.70	7 %
Taxes, other than income taxes	$ 3.40	$ 4.54	$ (1.14)	(25)%

(1) 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 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 relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also include the effect of derivative settlements (received or paid) for gas purchases.

(2) Total unhedged operating expenses equals total operating expenses less the derivatives settlements paid for gas purchases.

(3) Includes restructuring and other non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $0.91 per Boe and $1.55 per Boe for the three months ended September 30, 2019 and June 30, 2019, respectively.

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 are used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery.

Operating expenses are defined above in "How We Plan and Evaluate Operations". On an unhedged basis, operating expenses decreased to $18.13 per Boe for the third quarter 2019 compared to $18.94 for the second quarter 2019. The decrease includes $0.47 per Boe impact from electricity sales net of electricity generation expense and $0.44 per Boe lower lease operating expenses. Additionally, operating expenses, including hedge effects, decreased to $18.90 per Boe in the third quarter 2019 from $20.38 in the second quarter due to these same factors and $0.67 per Boe lower settled gas hedge losses period-over-period.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased by approximately $3 million, or 6%, to approximately $51 million for the three months ended September 30, 2019, compared to the three months ended June 30, 2019.

Lease operating expenses per Boe decreased to $18.74 for the three months ended September 30, 2019 compared to $19.18 per Boe for the three months ended June 30, 2019 driven by the increased production quarter-over-quarter. Fuel prices related to our California steam operations increased from the three months ended June 30, 2019. The average fuel cost for the third quarter of 2019 increased 32% to $2.67/MMBtu compared to $2.03/MMBtu for the second quarter of 2019. The increase in fuel costs was partially offset by decreases in facility, well, and lease maintenance costs during the third quarter of 2019. These fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses increased approximately $1 million or 20% to $4 million for the three months ended September 30, 2019 compared to the three months ended June 30, 2019. The increase reflected higher fuel costs and volumes due to decreased downtime for scheduled maintenance during the third quarter of 2019. These fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Losses on natural gas derivatives of $3 million for the three months ended September 30, 2019, consisted of $2 million losses on settled derivative contracts and $1 million mark-to-market valuation losses. The $9 million loss on natural gas derivatives for the three months ended June 30, 2019 resulted from $3 million losses on settled contracts and $6 million mark-to-market valuation losses. These losses were the result of the lower gas prices relative to the fixed prices of our derivative contracts.

Transportation expenses were comparable for the three months ended September 30, 2019 and June 30, 2019.

Marketing expenses were flat for the three months ended September 30, 2019 and June 30, 2019. Marketing expenses in these periods, which exclude the effects of hedging, represented the cost of natural gas purchased from third-parties.

General and administrative expenses increased by $0.3 million, or 2%, to approximately $16 million for the three months ended September 30, 2019 compared to the three months ended June 30, 2019. For the three months ended September 30, 2019 and June 30, 2019, general and administrative expenses included restructuring and other non-recurring costs of approximately $0.2 million and $1.5 million, respectively, and non-cash stock compensation costs of approximately $2.3 million and $2.4 million, respectively.

Adjusted general and administrative expenses, which exclude restructuring and other non-recurring costs and non-cash stock compensation costs, were $14 million or $5.13 per Boe for the third quarter 2019 compared to $12 million or $4.92/Boe for the second quarter 2019. This increase was partially due to higher insurance renewals and true-ups; however, the primary driver was the continuing development and growth of our corporate affairs department and activities whose purpose is to support our efforts and participation in the regulatory, political and legislative process primarily in California. Adjusted general and administrative expenses is a non-GAAP financial measure defined as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense. Please see "—Non-GAAP Financial Measure" for a reconciliation to the GAAP financial measure of general and administrative expenses.

DD&A increased by $4 million or 17% to approximately $28 million for the three months ended September 30, 2019 compared to the three months ended June 30, 2019. The increase was largely driven by higher production quarter-over-quarter.

Taxes, Other Than Income Taxes

	Three Months Ended			
	September 30, 2019	June 30, 2019	$ Change	% Change
	(in thousands)			
Severance taxes	$ 1,831	$ 1,873	$ (42)	(2)%
Ad valorem and property taxes	3,348	3,612	(264)	(7)%
Greenhouse gas allowances	4,070	5,863	(1,793)	(31)%
Total taxes other than income taxes	$ 9,249	$ 11,348	$ (2,099)	(18)%

Taxes, other than income taxes decreased in the three months ended September 30, 2019 by $2 million or 18%, compared to the three months ended June 30, 2019 largely due to decreased market rates for our greenhouse gas allowance requirements in the third quarter. Taxes, other than income taxes decreased to $3.40 per Boe in the third quarter of 2019 from $4.54 per Boe for the second quarter 2019.

Other operating (income) expenses

Other operating income largely consisted of a gain on sale of miscellaneous properties in the three months ended September 30, 2019 while other operating expenses in the quarter ended June 30, 2019 mainly consisted of excess abandonment costs.

Reorganization items, net

Reorganization items, net were not significant for the three months ended September 30, 2019 and June 30, 2019.

Income Tax Expense (Benefit)

Our effective tax rate remained flat at 27.7% for the three months ended September 30, 2019 and June 30, 2019.

Three Months Ended September 30, 2019 compared to Three Months Ended September 30, 2018.

	Three Months Ended September 30,			
	2019	2018	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 141,250	$ 147,004	$ (5,754)	(4)%
Electricity sales	7,460	14,268	(6,808)	(48)%
Gain (losses) on oil derivatives	45,509	(18,994)	64,503	n/a
Marketing and other revenues	453	669	(216)	(32)%
Total revenues and other	$ 194,672	$ 142,947	$ 51,725	36 %

Revenues and Other

Oil, natural gas and NGL sales decreased $6 million or 4% to $141 million for the three months ended September 30, 2019 compared to the three months ended September 30, 2018. Higher oil volumes were more than offset by lower oil, gas and NGL prices between these periods.

Electricity sales, representing sales to utilities, decreased by approximately $7 million, or 48%, to approximately $7 million for the three months ended September 30, 2019 compared to the three months ended September 30, 2018. The decrease was primarily due to the impact from lower natural gas fuel prices on unit sales prices during the third quarter in 2019 compared to 2018. Electricity sales also decreased due to lower unit sales caused by increased downtime during the third quarter in 2019 compared to the same period in 2018.

Gains on oil derivatives were $46 million, which included settled gains of $17 million, for the three months ended September 30, 2019, compared to losses of $19 million, which included settled losses of $1 million, for the three months ended September 30,

2018. Gains for the third quarter of 2019 and 2018 mostly resulted from the mark-to-market effect caused by decreasing oil prices relative to the fixed prices of our derivative contracts.

Marketing and other revenues were comparable for the three months ended September 30, 2019 and 2018. Marketing revenues in these periods represented sales of natural gas purchased from third-parties.

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 50,957	$ 51,649	$ (692)	(1)%
Electricity generation expenses	3,781	6,130	(2,349)	(38)%
Transportation expenses	2,067	2,318	(251)	(11)%
Marketing expenses	398	437	(39)	(9)%
General and administrative expenses	16,434	13,429	3,005	22 %
Depreciation, depletion and amortization	27,664	21,729	5,935	27 %
Taxes, other than income taxes	9,249	8,317	932	11 %
Losses (gains) on natural gas derivatives	3,008	(1,879)	4,887	n/a
Other operating (income) expenses	(550)	400	(950)	(238)%
Total expenses and other	113,008	102,530	10,478	10 %
Other income (expenses):				
Interest expense	(8,597)	(9,877)	1,280	(13)%
Other, net	(77)	347	(424)	(122)%
Reorganization items, net	(170)	13,781	(13,951)	(101)%
Income before income taxes	72,820	44,668	28,152	63 %
Income tax expense	20,171	7,683	12,488	163 %
Net income	52,649	36,985	15,664	42 %
Series A preferred stock dividends	—	(86,642)	86,642	(100)%
Net income (loss) available to common stockholders	$ 52,649	$ (49,657)	$ 102,306	n/a
Expenses per Boe:[1]				
Lease operating expenses	$ 18.74	$ 20.50	$ (1.76)	(9)%
Electricity generation expenses	1.39	2.43	(1.04)	(43)%
Electricity sales[1]	(2.74)	(5.66)	2.92	(52)%
Transportation expenses	0.76	0.92	(0.16)	(17)%
Transportation sales[1]	(0.01)	(0.07)	0.06	(86)%
Marketing expenses	0.15	0.17	(0.02)	(12)%
Marketing revenues[1]	(0.15)	(0.19)	0.04	(21)%
Derivatives settlements paid for gas purchases[1]	0.77	—	0.77	100 %
Total operating expenses	$ 18.90	$ 18.10	$ 0.80	4 %
Total unhedged operating expenses[2]	$ 18.13	$ 18.10	$ 0.03	— %
General and administrative expenses[3]	$ 6.04	$ 5.33	$ 0.71	13 %
Depreciation, depletion and amortization	$ 10.17	$ 8.62	$ 1.55	18 %
Taxes, other than income taxes	$ 3.40	$ 3.30	$ 0.10	3 %

(1) 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 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 relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also include the effect of derivative settlements (received or paid) for gas purchases.

(2) Total unhedged operating expenses equals total operating expenses less the derivatives settlements paid for gas purchases.

(3) Includes restructuring and other non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $0.91 per Boe and $1.08 per Boe for the three months ended September 30, 2019 and September 30, 2018, respectively.

Expenses and Other

Operating expenses, on an unhedged basis were essentially flat for the three months ended September 30, 2019 compared to the three months ended September 30, 2018. Lease operating expenses were $1.76 per Boe lower, offset by $1.88 increase from the net changes in electricity sales and expenses. Additionally, operating expenses, including hedge effects, increased to $18.90 per Boe for the third quarter 2019 from $18.10 per Boe for the third quarter 2018 due to these same factors and $0.77 per Boe of settled gas hedge loss impact. Operating expenses did not include gas hedge settlements for the third quarter 2018.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased approximately $0.7 million, or 1%, to approximately $51 million for the three months ended September 30, 2019, compared to the three months ended September 30, 2018.

Lease operating expenses per Boe were $18.74 for the three months ended September 30, 2019 compared to $20.50 per Boe for the three months ended September 30, 2018. This 9% decrease reflected lower gas costs, partially offset by higher facility processing and well servicing maintenance compared to the three months ended September 30, 2018. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses decreased by $2 million to $4 million for the three months ended September 30, 2019 compared to the same period in 2018. Decreased fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements discussed elsewhere.

Losses on natural gas derivatives of $3 million for the three months ended September 30, 2019, consisted of $2 million in losses on settled derivative contracts and $1 million in mark-to-market valuation losses. We did not have any natural gas derivatives during the three months ended September 30, 2018.

Transportation expenses decreased by less than $0.3 million to approximately $2.1 million for the three months ended September 30, 2019, compared to the three months ended September 30, 2018, mainly due to lower volumes shipped from our Rockies assets and the impact from selling our East Texas asset during the fourth quarter of 2018.

Marketing expenses were comparable for the three months ended September 30, 2019 and September 30, 2018. Marketing expenses in these periods, which exclude the effects of hedging, represented the cost of natural gas purchased from third-parties.

General and administrative expenses increased by approximately $3 million, or 22%, to approximately $16 million for the three months ended September 30, 2019 compared to the three months ended September 30, 2018. For the three months ended September 30, 2019 and September 30, 2018, general and administrative expenses also included restructuring and other non-recurring costs of approximately $0.2 million and $1.6 million, respectively, and non-cash stock compensation costs of approximately $2.3 million and $1.1 million, respectively.

Adjusted general and administrative expenses, which exclude restructuring and other non-recurring costs and non-cash stock compensation costs, were $14 million or $5.13/Boe for the three months ended September 30, 2019 compared to $11 million or $4.25/Boe for the three months ended September 30, 2018. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs related to our public company status, higher insurance renewals and true-ups, and the continuing development and growth of our corporate affairs department and activities whose purpose is to support our efforts and participation in the regulatory, political and legislative process primarily in California.

DD&A increased $6 million, or 27%, to approximately $28 million for the three months ended September 30, 2019 compared to the three months ended September 30, 2018, primarily due to the increased production and higher depreciation and depletion rates for 2019.

Taxes, Other Than Income Taxes

	Three Months Ended September 30,			
	2019	2018	$ Change	% Change
	(in thousands)			
Severance taxes	$ 1,831	$ 2,149	$ (318)	(15)%
Ad valorem and property taxes	3,348	3,165	183	6 %
Greenhouse gas allowances	4,070	3,002	1,068	36 %
Total taxes other than income taxes	$ 9,249	$ 8,317	$ 932	11 %

Taxes, other than income taxes increased for the three months ended September 30, 2019 by $1 million or 11%, compared to the three months ended September 30, 2018 due to higher greenhouse gas cost allowances and ad valorem and property taxes, partially offset by lower severance taxes than in the third quarter 2018. Greenhouse gas costs increased as a result of fewer free allowances from the state of California and higher spot prices for those allowances purchased, both of which increased the average unit cost of emissions incurred. The lower severance taxes in the third quarter of 2019 were the result of increased exemptions. Taxes, other than income taxes increased to $3.40 per Boe in the third quarter of 2019 from $3.30 for the third quarter 2018.

Other operating (income) expenses

Other operating income largely consisted of a gain on sale of properties in the three months ended September 30, 2019.

Interest Expense

Interest expense decreased in the three months ended September 30, 2019 by approximately $1 million or 13%, compared to the three months ended September 30, 2018 due to lower borrowings throughout the third quarter of 2019 compared to 2018.

Reorganization items, net

Reorganization items, net were insignificant for the three months ended September 30, 2019 and comprised $14 million of income for the three months ended September 30, 2018. The gain for the third quarter in 2018 was primarily due to the resolution of certain pre-emergence liabilities, partially offset by legal and other professional fees.

Income Tax Expense (Benefit)

Our effective tax rate was 27.7% for the three months ended September 30, 2019 and 17.2% for the three months ended September 30, 2018. The increase in the effective tax rate was primarily due to the release of our valuation allowance on deferred tax assets in 2018.

Nine Months Ended September 30, 2019 compared to Nine Months Ended September 30, 2018.

	Nine Months Ended September 30,			
	2019	**2018**	**$ Change**	**% Change**
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 409,259	$ 410,013	$ (754)	— %
Electricity sales	22,553	25,691	(3,138)	(12)%
Gain (losses) on oil derivatives	7,546	(131,781)	139,327	(106)%
Marketing and other revenues	1,918	2,288	(370)	(16)%
Total revenues and other	$ 441,276	$ 306,211	$ 135,065	44 %

Revenues and Other

Oil, natural gas and NGL sales were $409 million for the nine months ended September 30, 2019 and comparable to the nine months ended September 30, 2018 as increased oil volumes were mostly offset by decreased oil prices and gas volumes.

Electricity sales represent sales to utilities and decreased by approximately $3 million, or 12%, to approximately $23 million for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018. The decrease was due to lower sales prices, due to the link between sales price and lower natural gas pricing, combined with lower unit sales due to higher downtime in the nine months ended September 30, 2019, than the nine months ended September 30, 2018.

Gains on oil derivatives were $8 million, including settled gains of $29 million and mark-to-market losses of $21 million for the nine months ended September 30, 2019. Losses on oil derivatives were approximately $132 million, net of settled losses of $174 million, including $127 million for early-terminated derivatives for the nine months ended September 30, 2018.

Marketing and other revenues were comparable for the nine months ended September 30, 2019 and 2018. Marketing revenues in these periods represented sales of natural gas purchased from third-parties.

	Nine Months Ended September 30, 2019	2018	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 156,765	$ 137,468	$ 19,297	14 %
Electricity generation expenses	14,705	13,855	850	6 %
Transportation expenses	5,935	7,640	(1,705)	(22)%
Marketing expenses	1,670	1,424	246	17 %
General and administrative expenses	46,932	37,896	9,036	24 %
Depreciation, depletion and amortization	75,904	62,017	13,887	22 %
Taxes, other than income taxes	28,683	25,288	3,395	13 %
Losses (gains) on natural gas derivatives	10,342	(1,879)	12,221	n/a
Other operating expenses	3,814	522	3,292	631 %
Total expenses and other	344,750	284,231	60,519	21 %
Other income (expenses):				
Interest expense	(26,362)	(26,828)	466	(2)%
Other, net	79	135	(56)	(41)%
Reorganization items, net	(426)	23,192	(23,618)	(102)%
Income before income taxes	69,817	18,479	51,338	278 %
Income tax expense	19,294	3,145	16,149	513 %
Net income	50,523	15,334	35,189	229 %
Series A preferred stock dividends	—	(97,942)	97,942	(100)%
Net income (loss) available to common stockholders	$ 50,523	$ (82,608)	$ 133,131	n/a
Expenses per Boe:(1)				
Lease operating expenses	$ 20.31	$ 18.87	$ 1.44	8 %
Electricity generation expenses	1.91	1.90	0.01	1 %
Electricity sales(1)	(2.92)	(3.53)	0.61	(17)%
Transportation expenses	0.77	1.05	(0.28)	(27)%
Transportation sales(1)	(0.03)	(0.07)	0.04	(57)%
Marketing expenses	0.22	0.20	0.02	10 %
Marketing revenues(1)	(0.21)	(0.25)	0.04	(16)%
Derivatives settlements paid for gas purchases(1)	0.25	—	0.25	100 %
Total operating expenses	$ 20.28	$ 18.17	$ 2.11	12 %
Total unhedged operating expenses(2)	$ 20.03	$ 18.17	$ 1.86	10 %
General and administrative expenses(3)	$ 6.08	$ 5.20	$ 0.88	17 %
Depreciation, depletion and amortization	$ 9.84	$ 8.51	$ 1.33	16 %
Taxes, other than income taxes	$ 3.72	$ 3.47	$ 0.25	7 %

(1) 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 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 relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also include the effect of derivative settlements (received or paid) for gas purchases.

(2) Total unhedged operating expenses equals total operating expenses less the derivatives settlements paid for gas purchases.

(3) Includes restructuring and other non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.18 per Boe and $1.22 per Boe for the nine months ended September 30, 2019 and September 30, 2018, respectively.

Expenses and Other

Operating expenses, on an unhedged basis increased to $20.03 per Boe for the nine months ended 2019 from $18.17 per Boe for the nine months in 2018. The increase includes $1.44 per Boe higher lease operating expenses and $0.60 per Boe impact from electricity sales, partially offset by $0.28 per Boe lower transportation expenses. Additionally, operating expenses, including hedge effects, increased to $20.28 per Boe for the nine months ended 2019 from $18.17 for the nine months 2018 due to these same factors and $0.25 per Boe of settled gas hedge loss impact. Operating expenses did not include gas hedge settlements for the nine months ended 2018.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased by approximately $19 million, or 14%, to approximately $157 million for the nine months ended September 30, 2019, compared to the nine months ended September 30, 2018.

Lease operating expenses per Boe were $20.31 for the nine months ended September 30, 2019 compared to $18.87 per Boe for the nine months ended September 30, 2018. The increase for 2019 included $0.57 per Boe for well servicing and maintenance, $0.55 per Boe in higher fuel costs resulting from higher natural gas prices, and $0.49 per Boe in contract labor and services for tank and vessel maintenance, trucking and other costs compared to 2018.

Electricity generation expenses increased approximately $1 million or 6% to $15 million for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018, mostly due to higher natural gas costs during the first quarter 2019. These fuel costs exclude the the effects of natural gas derivative settlements mentioned elsewhere.

Losses on natural gas derivatives of $10 million for the nine months ended September 30, 2019 primarily represented $8 million of mark-to-market valuation losses, compared to gains of $2 million for the nine months ended September 30, 2018.

Transportation expenses decreased approximately $2 million to approximately $6 million for the nine months ended September 30, 2019, compared to the nine months ended September 30, 2018, mainly due to the impact from selling our East Texas asset during the fourth quarter of 2018 and lower volumes shipped from our Rockies assets.

Marketing expenses were comparable for the nine months ended September 30, 2019 and 2018. Marketing expenses in these periods, which exclude the effects of hedging, represented the cost of natural gas purchased from third-parties.

General and administrative expenses increased by approximately $9 million, or 24%, to approximately $47 million for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018. For the nine months ended September 30, 2019 and September 30, 2018, general and administrative expenses included restructuring and other non-recurring costs of approximately $3.1 million and $5.4 million, respectively, and non-cash stock compensation costs of approximately $6.1 million and $3.4 million, respectively.

Adjusted general and administrative expenses, which exclude restructuring and other non-recurring costs and non-cash stock compensation costs, were approximately $38 million or $4.90 per Boe for the nine months ended September 30, 2019 compared to $29 million or $4.00 per Boe for the nine months ended September 30, 2018. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs related to public company status, higher insurance renewals and true-ups, and the continuing development and growth of our corporate affairs department and activities whose purpose is to support our efforts and participation in the regulatory, political and legislative process primarily in California.

DD&A increased by approximately $14 million, or 22%, to approximately $76 million, for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018, primarily due to the increased production and higher depreciation and depletion rates for 2019.

Taxes, Other Than Income Taxes

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	$ Change	% Change
	(in thousands)			
Severance taxes	$ 4,407	$ 7,910	$ (3,503)	(44)%
Ad valorem and property taxes	10,105	9,723	382	4 %
Greenhouse gas allowances	14,171	7,655	6,516	85 %
Total taxes other than income taxes	$ 28,683	$ 25,288	$ 3,395	13 %

Taxes, other than income taxes increased in the nine months ended September 30, 2019 by $3 million or 13%, compared to the nine months ended September 30, 2018 due to higher greenhouse gas allowance costs, partially offset by lower severance taxes than in the nine months ended September 30, 2018. Greenhouse gas allowance costs increased as a result of fewer free allowances from the state of California and higher spot prices for those allowances purchased, both of which increased the average unit cost of emissions incurred. The lower severance taxes in the nine months ended September 30, 2019 were the result of increased exemptions. Taxes, other than income taxes, increased to $3.72 per Boe for the nine months ended 2019 from $3.47 for 2018.

Other operating expenses

Other operating expenses were $4 million in the nine months ended September 30, 2019 and mainly consisted of excess abandonment costs.

Interest Expense

Interest expense was flat for the nine months ended September 30, 2019 and the nine months ended September 30, 2018.

Reorganization items, net

Reorganization items, net consisted of essentially no expense for the nine months ended September 30, 2019, compared to $23 million of income primarily from the return of undistributed funds reserved for settlement of claims of general unsecured creditors for the nine months ended September 30, 2018.

Income Tax Expense (Benefit)

Our effective tax rate was 27.6% for the nine months ended September 30, 2019 and 17.0% for the nine months ended September 30, 2018. The increase in the effective tax rate was primarily due to the release of our valuation allowance on deferred tax assets in 2018.

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.

We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; 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.

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.

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 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 restructuring and other non-recurring 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 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.

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
			(in thousands)		
Adjusted EBITDA reconciliation to net income (loss):					
Net income	$ 52,649	$ 31,972	$ 36,985	$ 50,523	$ 15,334
Add (Subtract):					
Interest expense	8,597	8,961	9,877	26,362	26,828
Income tax expense	20,171	12,221	7,683	19,294	3,145
Depreciation, depletion and amortization	27,664	23,654	21,729	75,904	62,017
Derivative (gains) losses	(42,501)	(17,827)	17,115	2,796	129,902
Net cash received (paid) for scheduled derivative settlements	15,153	(3,326)	(1,052)	26,731	(47,161)
Other operating (income) expenses	(550)	3,119	400	3,814	522
Stock compensation expense	2,360	2,443	1,182	6,277	3,502
Restructuring and other non-recurring costs	219	1,513	1,598	3,061	5,359
Reorganization items, net	170	26	(13,781)	426	(23,192)
Adjusted EBITDA	$ 83,931	$ 62,756	$ 81,736	$ 215,188	$ 176,256

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
			(in thousands)		
Adjusted EBITDA and Levered Free Cash Flow reconciliation to net cash provided by (used in) operating activities:					
Net cash provided by operating activities	$ 65,320	$ 71,362	$ 56,880	$ 155,793	$ 7,334
Add (Subtract):					
Cash interest payments	14,864	1,272	15,902	30,136	19,199
Cash reorganization item (receipts) payments	—	—	(345)	—	1,007
Restructuring and other non-recurring costs	219	1,513	1,598	3,061	5,359
Derivative early termination payment	—	—	—	—	126,949
Other changes in operating assets and liabilities	3,528	(11,391)	7,701	26,198	16,408
Adjusted EBITDA	$ 83,931	$ 62,756	$ 81,736	$ 215,188	$ 176,256
Subtract:					
Capital expenditures - accrual basis	(63,488)	(56,645)	(40,243)	(169,217)	(94,505)
Interest expense	(8,597)	(8,961)	(9,877)	(26,362)	(26,828)
Cash dividends declared	(9,720)	(9,710)	(7,431)	(29,502)	(18,732)
Levered Free Cash Flow[(1)]	$ 2,126	$ (12,560)	$ 24,185	$ (9,893)	$ 36,191

(1) Levered Free Cash Flow, as defined by the Company, includes cash received for scheduled derivative settlements of $15 million in the three months ended September 30, 2019, cash paid for scheduled derivative settlements of $3 million and $1 million for the three months ended June 30, 2019 and September 30, 2018. Levered Free Cash Flow includes cash received for scheduled derivative settlements of $27 million in the nine months ended September 30, 2019 and cash paid for scheduled derivative settlements of $47 million for the nine months ended September 30, 2018.

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).

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
			(in thousands)		
Adjusted Net Income (Loss) reconciliation to net income (loss):					
Net income	$ 52,649	$ 31,972	$ 36,985	$ 50,523	$ 15,334
Add (Subtract):					
(Gains) losses on oil and natural gas derivatives	(42,501)	(17,827)	17,115	2,796	129,902
Net cash received (paid) for scheduled derivative settlements	15,153	(3,326)	(1,052)	26,731	(47,161)
Other operating (income) expenses	(550)	3,119	400	3,814	522
Restructuring and other non-recurring costs	219	1,513	1,598	3,061	5,359
Reorganization items, net	170	26	(13,781)	426	(23,192)
Total (subtractions) additions, net	(27,509)	(16,495)	4,280	36,828	65,430
Income tax benefit (expense) of adjustments at effective tax rate	7,620	4,569	(736)	(10,164)	(11,137)
Adjusted Net Income	$ 32,760	$ 20,046	$ 40,529	$ 77,187	$ 69,627

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.

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
			(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
G&A expenses	$ 16,434	$ 16,158	$ 13,429	$ 46,932	$ 37,896
Subtract:					
Restructuring and other non-recurring costs	(219)	(1,513)	(1,598)	(3,061)	(5,359)
Non-cash stock compensation expense (G&A portion)	(2,275)	(2,368)	(1,125)	(6,067)	(3,404)
Adjusted G&A	$ 13,940	$ 12,277	$ 10,706	$ 37,804	$ 29,133
Adjusted general and administrative expenses ($/MBoe)	$ 5.13	$ 4.92	$ 4.25	$ 4.90	$ 4.00

Liquidity and Capital Resources

Currently, we expect our primary sources of liquidity and capital resources will be Levered Free Cash Flow, and as needed, borrowings under the RBL Facility. Depending upon market conditions and other factors, we have issued and may issue additional equity and debt securities; however, we expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to fund maintenance operations, organic growth, interest, dividends 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.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock they authorized initial repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and we are not obligated to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

For the three months ended September 30, 2019, we did not repurchase shares under the stock repurchase program. For the nine months ended September 30, 2019, we repurchased 3,200,162 shares at an average price of $11.02 per share for $35 million, which is reflected as treasury stock. The Company has repurchased a total of 3,648,823 shares under the stock repurchase program for $39 million as of September 30, 2019.

Cash Dividends

Our board of directors approved $0.12 per share quarterly cash dividend on our common stock each quarter in 2019. We paid the third quarter dividend in October 2019 and declared the fourth quarter dividend in November 2019, which is payable in January 2020. As of October 31, 2019, the Company has paid approximately $47 million in dividends, since the inception of its dividend program.

The RBL Facility

As of September 30, 2019 our borrowing base was $400 million and we had $381 million available for borrowing under the RBL Facility. At September 30, 2019, we were in compliance with the financial covenants under the RBL Facility. In April 2019, we completed a borrowing base redetermination under our RBL Facility that resulted in our borrowing base being set at $750 million and we elected to limit lender commitments to $400 million. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations.

Corporate Organization

Berry Corp., as Berry LLC's parent company, has no independent assets or operations. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. Berry Corp. and Berry LLC currently do not have any other subsidiaries. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than under the RBL Facility. The RBL Facility permits Berry LLC to make distributions to Berry Corp. provided certain conditions are met. The conditions are currently met with significant margin. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

Hedging

We have protected a significant portion of our anticipated cash flows through 2020 and into 2021 using our commodity hedging program, including through fixed-price derivative contracts. We hedge crude oil production to protect against oil price decreases and we also hedge gas purchases to protect against price increases For information regarding risks related to our hedging program, see "Item 1A. Risk Factors—Risks Related to Our Business and Industry" in our Annual Report.

As of September 30, 2019, we had the following crude oil production and gas purchases hedges, with no changes through October 31, 2019.

	Q4 2019	FY 2020	FY 2021
Fixed Price Oil Swaps (Brent):			
Hedged volume (MBbls)	1,656	5,856	730
Weighted average price ($/Bbl)	$ 70.20	$ 64.25	$ 58.50
Fixed Price Oil Swaps (WTI):			
Hedged volume (MBbls)	92	121	—
Weighted average price ($/Bbl)	$ 61.75	$ 61.75	$ —
Oil basis differential swaps (Brent-WTI basis swaps):			
Hedged volume (MBbls)	46	—	—
Weighted average price ($/Bbl)	$ (1.29)	$ —	$ —
Sold Oil Call Options (Brent):			
Hedged volume (MBbls)	92	—	—
Weighted average price ($/Bbl)	$ 81.00	$ —	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	4,905,000	17,385,000	900,000
Weighted average price ($/MMBtu)	$ 2.90	$ 2.88	$ 2.50
Fixed Price Gas Purchase Swaps (SoCal Citygate):			
Hedged volume (MMBtu)	460,000	1,525,000	—
Weighted average price ($/MMBtu)	$ 3.80	$ 3.80	$ —

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

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
Crude Oil (per Bbl):					
Realized sales price, before the effects of derivative settlements	$ 57.92	$ 61.69	$ 67.67	$ 58.79	$ 65.97
Effects of derivative settlements	$ 7.31	$ 0.13	$ (0.44)	$ 4.30	$ (8.01)
Natural Gas (per MMBtu):					
Purchase price, before the effects of derivative settlements	$ 2.67	$ 2.03	$ 3.88	$ 3.17	$ 2.99
Effects of derivative settlements	$ 0.30	$ 0.53	$ —	$ 0.09	$ —

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 and into 2021 as part of our crude oil hedging program. Our generally low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production. Oil derivative settlements increased in the third quarter of 2019 when compared to prior periods in the table above, as a result of a decrease in Brent prices compared to the respective hedge strike prices, as well as increased oil volumes hedged.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Nine Months Ended September 30,	
	2019	2018
	(in thousands)	
Net cash:		
Provided by operating activities	$ 155,793	$ 7,334
Used in investing activities	(167,664)	(82,375)
(Used in) provided by financing activities	(56,809)	30,216
Net decrease in cash, cash equivalents and restricted cash	$ (68,680)	$ (44,825)

Operating Activities

Cash provided by operating activities increased for the nine months ended September 30, 2019 by approximately $148 million when compared to the nine months ended September 30, 2018, primarily due to the early termination of certain hedge contracts paid during the second quarter of 2018, the increase in derivative cash settlements received, offset by the increased operating costs and the semi-annual interest payments on our 2026 Senior Unsecured Notes paid for the first time in August 2018, and other working capital changes.

Investing Activities

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

	Nine Months Ended September 30,	
	2019	2018
	(in thousands)	
Capital expenditures:(1)		
Development of oil and natural gas properties	$ (153,420)	$ (74,447)
Purchase of other property and equipment	(12,394)	(11,305)
Acquisition of properties	(2,819)	—
Proceeds from sale of properties and equipment and other	969	3,377
Cash used in investing activities	$ (167,664)	$ (82,375)

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

Cash used in investing activities increased $85 million for the nine months ended September 30, 2019 when compared to the same period in 2018, primarily due to an increase in capital spending in accordance with the 2019 capital budget.

Financing Activities

Cash used by financing activities was approximately $57 million for the nine months ended September 30, 2019 and was primarily used to purchase treasury stock of $36 million and pay dividends on common stock of approximately $29 million, offset by approximately $10 million of net borrowings under the RBL Facility for monthly working capital fluctuations. 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 Senior Unsecured Notes and net proceeds of $111 million from our IPO in July, offset by $379 million in 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 rights to our common shares from certain claimsholders originating from the bankruptcy process and $11 million cash dividends declared on our Series A Preferred Stock.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2018 to September 30, 2019 are discussed below.

	September 30, 2019	December 31, 2018
	(in thousands)	
Cash and cash equivalents	$ —	$ 68,680
Accounts receivable, net	$ 63,673	$ 57,379
Derivative instruments assets - current and long-term	$ 63,692	$ 91,885
Other current assets	$ 16,335	$ 14,367
Property, plant & equipment, net	$ 1,607,810	$ 1,442,708
Other non-current assets	$ 14,068	$ 17,244
Accounts payable and accrued liabilities	$ 145,360	$ 144,118
Derivative instruments liabilities - current and long-term	$ 3,534	$ —
Long-term debt	$ 402,290	$ 391,786
Asset retirement obligation	$ 122,733	$ 89,176
Other non-current liabilities	$ 29,188	$ 14,902
Equity	$ 997,344	$ 1,006,446

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

The $6 million increase in accounts receivable was driven mostly by higher sales period-over-period, partially offset by lower hedge settlements received.

The $25 million decrease in derivative instruments assets and liabilities reflected the decrease in the mark-to-market values relative to the strike price of the derivatives at the end of each period presented, as well as the change in positions held at the end of each period and the settlements received throughout the period.

The $2 million increase in other current assets includes $3 million for materials inventory related to our capital development program, offset by a decrease in oil inventories of $1 million.

The $165 million increase in property, plant and equipment was largely the result of increased capital investments in oil and gas properties, as well as revisions to timing and cost estimates in our asset retirement obligations noted below, partially offset by increased accumulated depreciation associated with such properties.

The $3 million decrease in other non-current assets was primarily due to amortization of debt issuance costs.

The increase in accounts payable and accrued liabilities included approximately $20 million for the increased current portion of the asset retirement obligation offset by decreased accruals for interest of $7 million, royalties of $6 million, and various capital and operating costs of $6 million.

The nearly $11 million increase in long-term debt represented borrowing and repayment activity from our RBL Facility for monthly working capital fluctuations.

The increase in the long-term portion of the asset retirement obligation largely reflected revisions to timing and cost estimates of $57 million, $6 million for new wells, and accretion expense of $5 million. A significant portion of the change in estimate was a result of California's new idle well regulations which became effective in the second quarter and accelerated the timing of abandonment of certain long existing idle wells. These increases were partially offset by liabilities settled during the period of $15 million and an increase to the current portion of the asset retirement obligation of $20 million due to the change in timing and estimated costs.

The increase in other noncurrent liabilities represented an additional greenhouse gas liability of $14 million for production during the nine months ended September 30, 2019, which is due for payment more than one year from September 30, 2019.

The decrease in equity of $9 million was due to the purchase of treasury stock for $35 million and common stock dividends declared of $30 million. These decreases were offset by net income of $51 million and stock-based incentive awards of $6 million.

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.

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, 2019 and December 31, 2018. 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, 2019, we are not aware of material indemnity claims pending or threatened against us.

In April 2019, we sold our outstanding claims in the Pacific Gas & Electric bankruptcy at an immaterial loss.

Contractual Obligations

As of September 30, 2019, we had entered into agreements to replace our Bakersfield, California office lease for approximately $11 million in aggregate over 8 years beginning August 2019. The annual costs under our former office lease, which ended in October 2019, were similar to the costs under the new leases.

Recently Adopted Accounting and Disclosure Changes

See Note 1, Basis of Presentation, in the Notes to Consolidated Condensed Financial Statements in Part I, Item 1 of this Form 10-Q.

Cautionary Note Regarding Forward-Looking Statements

The information included or incorporated by reference in this prospectus or in any accompanying prospectus supplement includes forward-looking statements involving 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 expenditures, return of capital, improvement of recovery factors 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 us are discussed above in “Risk Factors” in this prospectus, in any applicable prospectus supplement and in the documents incorporated by reference, including our most recent Annual Report on Form 10-K and other filings with the Securities and Exchange Commission.

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

- volatility of oil, natural gas and NGL prices;
- price and availability of natural gas and electricity;
- our ability to use derivative instruments to manage commodity price risk;

- 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;
- 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 ability to replace our reserves through exploration and development activities;
- our ability to obtain timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells;
- changes in tax laws;
- 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;
- ineffectiveness of internal controls;
- concerns about climate change and other air quality issues;
- catastrophic events;
- litigation;
- our ability to retain key members of our senior management and key technical employees; and
- information technology failures or cyber attacks.

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

All forward-looking statements, expressed or implied, included in this prospectus 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, 2019, 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 2018 Annual Report, except as discussed below.

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 to the extent unhedged. In addition, a non-cash write-down of our oil and gas properties may be required if commodity prices experience a significant decline.

We have hedged a large portion of our expected crude oil production and our natural gas purchase requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls and puts to hedge. We do not enter into derivative contracts for speculative trading purposes and we have not accounted for our derivatives as cash-flow or fair-value hedges. We continuously consider the level of our oil production and gas purchases that it is appropriate to hedge based on a variety of factors, including, among other things, current and future expected commodity prices, our overall risk profile, including leverage, size and scale, as well as any requirements for, or restrictions on, levels of hedging contained in any credit facility or other debt instrument applicable at the time. Currently, our hedging program mainly consists of swaps.

We determine the fair value of our oil and natural gas derivatives using valuation techniques which utilize market quotes and pricing analysis. Inputs include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate data provided by third parties by understanding the valuation inputs used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. At September 30, 2019, the fair value of our hedge positions was a net asset of approximately $60 million. A 10% increase in the oil and natural gas index prices above the September 30, 2019 prices would result in a net asset of approximately $27 million, which represents a decrease in the fair value of our derivative position of approximately $34 million; conversely, a 10% decrease in the oil and natural gas index prices below the September 30, 2019 prices would result in a net asset of approximately $110 million, which represents an increase in the fair value of approximately $50 million. For additional information about derivative activity, see Note 3.

Actual gains or losses recognized related to our derivative contracts depend exclusively on the price of the underlying commodities on the specified settlement dates provided by the derivative contracts.

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, they each concluded that our disclosure controls and procedures were effective as of September 30, 2019.

There were no changes in the Company's internal control over financial reporting during the third quarter of 2019 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II – Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 4 to the condensed 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, 2018 included in the Annual Report.

Item 1A. Risk Factors

In addition to factors noted in our most recent Annual Report, additional factors that may curtail, delay or cancel our scheduled drilling projects and ongoing operations, include the following:

- power outages imposed by utilities which provide a portion of our electricity needs in order to avoid fire hazards and inspect lines in connection with seasonal strong winds, have begun to occur this year and may impact our operations;

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

Stock Repurchase Program

On December 13, 2018, our Board of Directors announced it had adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock they authorized initial repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and we are not obligated to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

The Company did not repurchase stock under the stock repurchase program during the three months ended September 30, 2019. As of September 30, 2019 we have repurchased a total of 3,648,823 shares under the stock repurchase program for $39.2 million with approximately $10.9 million of shares that may yet be purchased under the plan.

Item 6. Exhibits

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.2	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Exhibit 3.2 of Form 8-K filed July 30, 2018)
3.3	Second Amended and Restated Bylaws of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.3 of Form 8-K filed July 30, 2018)
3.4	Certificate of Designation of Series A Convertible Preferred Stock of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.4 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.5	Certificate of Amendment to Certificate of Designation (incorporated by reference to Exhibit 3.1 of Form 8-K filed July 30, 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
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

GLOSSARY OF COMMONLY USED 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:

"*Adjusted EBITDA*" is a non-GAAP financial measure defined as earnings before interest expense; income taxes; depreciation, depletion, and amortization; 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 gains and losses on sale of assets, restructuring costs and reorganization items.

"*Adjusted G&A*" or "*Adjusted General and Administrative Expenses*" is a non-GAAP financial measure defined as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense.

"*Adjusted Net Income (Loss)*" is a non-GAAP financial measure defined 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.

"*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.

"*BLM*" means the U.S. Bureau of Land Management.

"*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.

"*Break even*" means the Brent price at which we expect to generate positive Levered Free Cash Flow.

"*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.

"*DD&A*" means depreciation, depletion & amortization.

"*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 7, 2019	*/s/* Cary Baetz
		Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	November 7, 2019	*/s/* M. S. Helm
		Michael S. Helm Chief Accounting Officer (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, A. T. "Trem" 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 7, 2019

/s/ A.T. Smith

A. T. "Trem" Smith

President and Chief 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 7, 2019

/s/ Cary Baetz

Cary Baetz

Executive Vice President and Chief 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, 2019, as filed with the Securities and Exchange Commission on November 7, 2019 (the "Report"), A. T. "Trem" 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 7, 2019

/s/ A. T. Smith

A. T. "Trem" Smith
President and Chief Executive Officer

/s/ Cary Baetz

Cary Baetz
Executive Vice President and
Chief 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.